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March 22, 2019

Via Hand Delivery
Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief*
Council Docket No. UD-18-07

Dear Ms. Johnson:

On behalf of Entergy New Orleans, LLC ("ENO" or the "Company"), please find enclosed for your further handling an original and three copies of the Rebuttal Testimony (and exhibits) of Joshua B. Thomas; Rebuttal Testimony (and exhibits) of Robert B. Hevert; the Adopting Direct and Rebuttal Testimony (and exhibits) of Matthew S. Klucher; Rebuttal Testimony (and exhibits) of Myra L. Talkington; Rebuttal Testimony (and exhibits) of D. Andrew Owens; Rebuttal Testimony (and exhibits) of Ahmad Faruqui; Rebuttal Testimony (and exhibits) of Michelle P. Bourg; Rebuttal Testimony of Raiford L. Smith; Rebuttal Testimony (and exhibits) of Donald J. Clayton; Rebuttal Testimony (and exhibits) of Robert Breedlove; Rebuttal Testimony (and exhibits) Rory L. Roberts; Rebuttal Testimony (and exhibits) of Kenneth F. Gallagher; and the Adopting Testimony of Laura K. Beauchamp (which adopts the Revised Direct Testimony filed by Orlando Todd on September 21, 2018 in this proceeding). Please file an original and two copies into the record in the above referenced matter and return a date-stamped copy to our courier.

Please note that certain of the exhibits and/or work papers of the witnesses contain Highly Sensitive Protected Materials and are being provided this date to appropriate reviewing representatives generally in accordance with the terms of the Council's Official Protective Order set forth in Resolution R-07-432 via electronic means.

Should you have any questions regarding the above/attached, please do not hesitate to contact me.

With kindest regards, I remain

Sincerely,

Alyssa Maurice-Anderson

AMA/amb
Enclosures
cc: Official Service List (*via email* only)

CERTIFICATE OF SERVICE

I hereby certify that I have this 22nd day of March, 2019, served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual, by: ☒ electronic mail, ☐ facsimile, ☒ hand delivery, and/or by depositing same with ☒ overnight mail carrier, or ☐ the United States Postal Service, postage prepaid.

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Alyssa Maurice-Anderson

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	**DOCKET NO. UD-18-07**
GAS RATES PURSUANT TO COUNCIL	**)**	
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

JOSHUA B. THOMAS

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joshua B. Thomas. My business address is 639 Loyola Avenue, New Orleans, Louisiana, 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans ("Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. ARE YOU THE SAME JOSHUA B. THOMAS WHO FILED REVISED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF ENO?

A. Yes.

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has a several purposes, including providing a high-level overview of the Company's rebuttal testimony by introducing ENO's rebuttal witnesses, as well as addressing various policy issues identified in the direct testimony of the Council's Advisors ("Advisors"), Messrs. Baron, Baudino and Kollen on behalf of the Crescent City Power Users' Group ("CCPUG"), Messrs. Brubaker and Walters on behalf of Air Products and Chemicals, Inc. ("APC"), Mr. Barnes and Ms. Morgan on behalf of the Alliance for Affordable Energy ("AAE"). In particular, I address policy issues with respect to the following: ENO's proposed electric and gas formula rate plans and the treatment of certain costs (*e.g.*, New Orleans Power Station) under that framework; the Algiers residential rate transition plan; the allocation of purchase power agreement ("PPA") capacity expenses; the Reliability Incentive Mechanism Plan; ENO's capitalization (including the use and the treatment of short-term debt); ENO's proposed riders – Electric and Gas Advanced Metering Infrastructure ("AMI") Charge Riders, the Distribution Grid Modernization ("DGM") Rider, the Demand-Side Management Cost Recovery Rider ("DSMCR"), and the Gas Infrastructure Replacement Program ("GIRP") Rider – and certain existing riders – the Purchased Power and Capacity Acquisition Cost Recovery ("PPCACR") Rider and the Securitized Storm Cost Offset ("SSCO") Rider; and the ratemaking treatment of certain items such as, the Accumulated Deferred Income Tax ("ADIT") associated with retired legacy electric and gas meters (*i.e.*, stranded meters); prepaid pension asset, restricted stock incentive plan, storm restoration capital costs, and the amortization of certain proposed regulatory assets.

III. OVERVIEW OF REBUTTAL FILING

Q5. WHAT IS THE COMPANY'S OVERALL RESPONSE TO THE DIRECT TESTIMONY OF THE OTHER PARTIES?

A. As was stated in the Revised Application, ENO is seeking the establishment of reasonable initial rates and rate structures from this proceeding that will facilitate ENO maintaining its financial condition to support making investments to deliver significant advances in technology designed to increase the level of service experiences by customers and required by the Council's policies. The Company believes that the other parties' Direct Testimony is informative regarding their concerns on that subject and demonstrates the need for collaboration in certain areas to convert positions into detailed, vetted action items so that the Council may issue a decision that produces just and reasonable rates and balances all stakeholders' interests.

The Company's believes that the Advisors' Direct Testimony is constructive in proposing a formula rate plan ("FRP") framework that, in most respects, attempts to address the Company's concerns regarding regulatory lag in this period of significant investment for the benefit of customers. However, the Advisors recommend an unreasonably low authorized return on equity ("ROE"), and the recommendation wholly erodes any opportunity for progress through the FRP structure. In addition, some of the Advisors' recommendations regarding the FRP procedures present significant obstacles to achieving the regulatory and administrative efficiencies that an FRP is designed to provide. ENO also believes that an opportunity exists for greater progress as it relates to implementation of demand-side management to ensure that it is placed on a level playing field with supply-side resources, as the Council indicated in Resolution R-07-600. Notwithstanding these issues, from the Company's perspective, the Advisors' recommendations present otherwise common ground to support further collaboration in establishing just and reasonable rates.

The Direct Testimony on behalf of the AAE, especially aided with understanding gained from the deposition of Pamela G. Morgan, indicates the potential to find common ground in the relationship between decoupling and changes in the cost of service. The

Direct Testimony on behalf of APC, a large industrial customer, showed common ground in the area of revenue allocation by acknowledging the Council's previous allocation of the capacity costs associated with the PPAs sourced from the unregulated portion of River Bend Station ("River Bend 30%") and the wholesale baseload resources of Entergy Arkansas, LLC ("EAL WBL").

Q6. PLEASE IDENTIFY THE OTHER WITNESSES FILING REBUTTAL TESTIMONY ON BEHALF OF ENO.

A. Below is a listing of the witnesses filing Rebuttal Testimony and the main areas covered by each's testimony. Please note that new witnesses are included in this list, some of whom are adopting the previously filed Revised Direct Testimony of certain former witnesses.

- Robert B. Hevert – Mr. Hevert responds to the Advisors', CCPUG's, and APC's return on equity recommendations.
- Matthew S. Klucher – Mr. Klucher responds to the Advisors' recommendations regarding cost of service and allocation factor development. Mr. Klucher also adopts substantially all of the Direct Testimony of Phillip B. Gillam.
- Myra L. Talkington – Ms. Talkington responds to the Advisors', CCPUG's, and the AAE's recommendations regarding cost allocation, rate design, and the level of the electric residential customer charge.

- D. Andrew Owens – Mr. Owens responds to the Advisors' and the AAE's recommendations regarding decoupling, Energy Smart cost recovery, community solar, electric vehicle charging infrastructure investments, and BSI's proposed Customer Lowered Electricity Price.
- Dr. Ahmad Faruqui – Dr. Faruqui responds to the Advisors' and the AAE's recommendations regarding demand-side management cost recovery and the level of the electric residential customer charge.
- Michelle P. Bourg – Ms. Bourg's testimony addresses recommendations regarding the GIRP Rider and the treatment of non-jurisdictional customers.
- Raiford L. Smith – Mr. Smith responds to the Advisors' recommendations regarding the proposed Fixed Bill Option and the ratemaking treatment of pre-pay balances in future base rate proceedings.
- Donald J. Clayton – Mr. Clayton's testimony responds to CCPUG's recommendations with respect to the service life and net salvage related to the Union Power Block 1 and the amortization period for the general plant deficiency.
- Robert A. Breedlove – Mr. Breedlove's testimony responds to CCPUG's recommendation to extend the service life of Union Power Block 1 for depreciation purposes.
- Rory L. Roberts – Mr. Roberts's testimony addresses income tax-related recommendations from the Advisors and CCPUG.

- Kenneth F. Gallagher – Mr. Gallagher responds to CCPUG's recommendation to include dividends in the calculation of the cash working capital adjustment.
- Ms. Laura K. Beauchamp – adopts the Direct Testimony of Orlando Todd.

Additionally, I note that the Company has not submitted rebuttal testimony regarding the Fuel Adjustment Clause ("FAC") Rider Schedule. There are no substantive disputes regarding the schedule. The only outstanding issue concerns which over and under collections, if any, should be included in the rider, which is dependent on the final resolution of allocation issues. ENO proposes that this component of the rider be addressed in the compliance filing process.

IV. ELECTRIC AND GAS FORMULA RATE PLANS

Q7. WHICH WITNESSES HAVE FILED DIRECT TESTIMONY ADDRESSING ENO'S PROPOSED ELECTRIC AND GAS FRPS?

A. Advisors witnesses Messrs. Rogers and Prep address the proposed Electric and Gas FRPs. Also, CCPUG witness Mr. Kollen addresses the proposed Electric and Gas FRPs. AAE witness Ms. Morgan addresses the Electric FRP as it relates to decoupling. Company witness Mr. Owens responds to Ms. Morgan's testimony in his Rebuttal Testimony.

Q8. PLEASE SUMMARIZE THE PROPOSED ELECTRIC AND GAS FRPS PRESENTED IN ENO'S REVISED DIRECT TESTIMONY.

A. ENO's proposed electric and gas FRP riders are based largely on the FRPs for the respective product lines (Electric and Gas) previously approved by the Council. As set forth in the Revised Direct Testimony of former Company witness Phillip B. Gillam (later adopted by Mr. Klucher), ENO's FRPs include, among others, the following features:

- use of the previous calendar year as the Evaluation Period (*i.e.*, historic test year);
- use of the authorized return on equity set in this proceeding as the target Evaluation Period Cost of Equity ("EPCOE");[1]
- a dead band of plus or minus 50 basis points centered on the EPCOE, in which there would be no change in rates;
- a formula that adjusts the FRP revenue level for the Evaluation Period to prospectively earn the EPCOE, commonly referred to as "resetting to the midpoint," if the Earned Rate of Return on Equity ("EROE") is above or below the dead band;
- a seventy-five day review period;
- a specified dispute resolution procedure; and
- a three-year term.

[1] ENO has proposed that the initial EPCOE for electric operations would be set to 10.5% (in connection with the proposed Reliability Incentive Mechanism described in my Revised Direct Testimony filed in this proceeding) and 10.75% for gas operations.

ENO's proposed FRP for electric operations also includes a new provision for a decoupling pilot program consistent with Council Resolution R-16-103 and a provision to facilitate the recovery of the estimated annual non-fuel revenue requirement of the New Orleans Power Station.

Q9. THE ADVISORS ASSERT THAT ENO'S PROPOSED FRPS COULD BE MODIFIED SO AS TO MAKE CERTAIN PROPOSED RIDERS UNNECESSARY. WHAT IS YOUR RESPONSE?

A. Incorporating forward-looking pro forma adjustments to account for known and measurable costs (and attendant revenue changes) in the calendar year following the FRP evaluation period in a properly structured FRP would address the Company's concerns regarding regulatory lag to a great degree. I am encouraged by the Advisors' recognition that circumstances indicate that regulatory lag should be mitigated and the following testimony from Mr. Rogers's in that regard:

> To mitigate concerns related to regulatory lag, witness Prep recommends that the Council approve an annual Electric utility FRP and annual Gas utility FRP for a period of three years. As proposed, the FRP would provide for an annual adjustment to ENO electric and Gas Rates to reduce the time between regulatory base rate actions and mitigate regulatory lag. Additionally, and to further mitigate regulatory lag, Witness Prep recommends that ENO be allowed to include prospective proforma adjustments for known and measurable capital additions budgeted for the 12-month period immediately following the FRP test year.[2]

[2] Direct Testimony Joseph W. Rogers, P.E. at 21-22; Direct Testimony of Victor Prep at 78 ("The additional provision for FRP adjustments would state: 'ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period.'"); Deposition of Victor M. Prep on March 14, 2019 at 54. The portions of the deposition cited herein are included in Exhibit JBT-11 *in globo*.

Q10. DOES ENO AGREE THAT SUCH A PROSPECTIVE ADJUSTMENT IN THE FRPS WOULD MAKE SOME OF ENO'S PROPOSED RIDERS UNNECESSARY?

A. Yes, at least for the term of the FRPs. The Advisors proposed prospective treatment of known and measurable costs and attendant revenue changes would mitigate the need for the Electric and Gas AMI Charge Rider[3] and the DGM Rider. In addition, there would need to be a provision made to implement riders should the FRPs terminate after the initial term.

Q11. WHY WOULD THE OTHER RIDERS REMAIN NECESSARY DESPITE FORWARD-LOOKING ADJUSTMENTS IN THE FRPS?

A. The GIRP Rider would remain necessary due to the nature and timing of the GIRP, which is expected to take place over ten years – a period significantly longer than the proposed term of the Gas FRP.[4] The GIRP Rider would provide the regulatory certainty that 1) is needed to assure investors that ENO will have a mechanism in place to provide ENO an opportunity to recover its significant, prudently incurred investment in this project and 2) facilitates the Company's ability to maintain qualified contractors throughout the duration of the project at a time when there is robust demand and competition for these resources.

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[3] It should be noted, however, that the AMI Charge Riders also served the purpose of providing for a specific cost allocation approach that the Council may want to continue to consider with respect to those costs if they are to be recovered through base rates instead of a customer-specific charge. I provided further rationale for this allocation methodology in my Direct Testimony.

[4] If the Council does not approve the GIRP Rider, then the Council should include in the gas revenue requirement $2.0 million associated with Underground Conflicts Expense, which is now budgeted to occur in 2019.

Additionally, the PPCACR Rider would remain necessary due to similar timing considerations. The PPCACR Rider provides for recovery of non-fuel costs of new, Council-approved resources when there is no Electric FRP in effect. Currently, there is no ongoing project that ENO would seek to recover through the PPCACR Rider, given no opposition to the recovery of the non-fuel costs associated with the New Orleans Power Station ("NOPS") through the proposed Electric FRP. However, the Company believes that this rider should continue with its proposed scope because it could serve as a recovery mechanism for Company investments in solar photovoltaic ("PV") resources, including the 90 megawatt investment in solar that ENO has proposed to the Council or other emerging technology to meet renewable resource needs the Council has and will continue to identify in the coming years.

Although the Advisors and CCPUG have argued that the PPCACR Rider operates automatically, Paragraph I of the proposed PPCACR Rider states that the only non-fuel costs that may be recovered through the rider are those associated with a new resource authorized by the Council. Therefore, there is no harm to customers from the Council adopting the proposed scope of the PPCACR Rider.

Q12. ARE THERE OTHER FRP-RELATED ADVISOR RECOMMENDATIONS WITH WHICH THE COMPANY DISAGREES?

A. Yes. ENO would not be able to agree to an FRP that includes an ROE at the level that the Advisors and other parties proposed, as these recommendations are unreasonably low and would result in one of the lowest ROEs implemented for any utility with generation, transmission, distribution, and customer service obligations, and by far the lowest ROE among the Entergy Operating Companies, including those with forward test year formula rate plans. The ROE recommendation is especially egregious given ENO's operating and risk profile. As I explained in my Revised Direct Testimony, a utility must invest capital in order to make improvements needed to serve customers, which is sourced from equity and debt. It is neither possible nor practical to force a utility to fund investment with the expectation of earning an unreasonably low return, nor is it reasonable or prudent to fund that investment using a disproportionate level of debt due to underfunded equity capital. As a result, a low ROE determination can prohibit the timely deployment and realization of corresponding benefits of projects like AMI, Grid Modernization, Smart Cities, and other substantial investments. Company witness Mr. Hevert addresses the parties' proposed ROE recommendations and emphasizes why the Advisors' recommendation is an extreme outlier.

The Council has expressed aggressive goals with respect to Demand Side Management ("DSM") savings targets for customers, and ENO has a desire to work with the Council and other parties to assess and pursue those goals. ENO believes that the known and measurable changes to the FRP should include revenue adjustments for Lost Contribution to Fixed Costs ("LCFC") using the Council-approved formula for calculating such adjustments established in Resolution R-09-136. If these changes are implemented, recovery of LCFC may not need to be included in Rider DSMCR, or another mechanism the Council may approve for the recovery of DSM investments. Mr. Owens discusses this further with respect to the application of Rider DSMCR.

Additionally, while the Advisors and ENO share a common goal on how a decoupling mechanism pursuant to Resolution R-16-103 should be incorporated into the Electric FRP, Mr. Klucher addresses certain concerns the Company has in achieving that end.

Also, as I discuss in greater detail later, the Company has concerns with the Advisors' approach to addressing the rate disparity between the Legacy ENO and the Algiers residential customers.

Q13. MR. KOLLEN ARGUES THAT PROPOSED FORMULA RATE PLANS SHOULD NOT USE CALENDAR YEAR 2019 AS THE FIRST EVALUATION PERIOD. DO YOU AGREE?

A. No. The Council previously has used the calendar year when new base rates go into effect as the first evaluation period for multi-year FRPs. This occurred with respect to the 2003 evaluation period under ENO's first FRPs pursuant to Resolution R-03-272 and the 2009 evaluation period under ENO's second FRPs pursuant to Resolution R-09-136. This same approach was used by the Louisiana Public Service Commission following Entergy Louisiana, LLC's ("ELL") last base rate case, which ELL, like ENO here, also sought a three-year FRP. Despite Mr. Kollen's claims to the contrary, the proposed Electric and Gas FRPs' structure is consistent with reviewing and adjusting rates prospectively, if necessary, based on a historic 2019 calendar year Evaluation Period.

Q14. CCPUG WITNESS MR. BAUDINO ARGUES THAT THE PROPOSED FORMULA RATE PLANS, EXHIBITS PBG-7 AND PBG-9, SUFFICIENTLY REDUCE REGULATORY LAG AND THE DGM AND GIRP RIDERS ARE UNNECESSARY. DO YOU AGREE?

A. No. As I explained in my Revised Direct Testimony, regulatory lag, especially in the context of ENO's plan to invest heavily in its infrastructure to bring benefits to customers, reduces cash flow, weakens financial integrity, and, thus, harms customers through increased capital costs. Mr. Baudino's testimony includes no analysis of ENO's investment plans and the implications of regulatory lag in the near future, which I illustrated in Exhibit JBT-8, and the Council should reject this argument.

V. ALGIERS RESIDENTIAL RATE TRANSITION PLAN

Q15. PLEASE SUMMARIZE THE POSITIONS OF THE PARTIES OPPOSING THE COMPANY'S PROPOSED ALGIERS RESIDENTIAL RATE TRANSITION ("ARRT") PLAN.

A. The Advisors oppose the ARRT Plan and outline their own plan for Algiers residential customers. CCPUG criticizes the ARRT Plan but will not oppose the ARRT Plan if the first $3.325 million of any reduction in ENO's proposed base rate revenue requirement increase are allocated to the rate classes – Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes – that bear re-allocated costs under the ARRT Plan.

Q16. IS THERE ANY DISPUTE REGARDING THE FACTS RECOUNTED IN YOUR REVISED DIRECT TESTIMONY THAT LED TO THE DISPARITY IN THE RATES OF ALGIERS RESIDENTIAL CUSTOMERS AND LEGACY ENO CUSTOMERS?

A. No.

Q17. DOES THE COMPANY OPPOSE THE ADVISORS' PROPOSED PLAN?

A. The Company has several concerns with the Advisors' proposed plan and respectfully cannot support it without some modifications.

The ARRT Plan proposed by ENO provided for definitive rate changes to occur in the future that start the transition to a single, uniform residential rate structure, which are set forth in Table 1 of my Revised Direct Testimony. ENO proposes that these rate changes occur regardless of other rate changes because Algiers residential customers are not bearing a proportionate share of the costs of service as compared to that allocated to all other ENO residential customers. By contrast, while the ARRT Plan proposes that all residential customers be treated the same with respect to all future rate changes, which includes changes pursuant to the Electric FRP, including the interim rate adjustment associated with the NOPS, the Advisors' plan does not provide such a path recommended to achieve rate parity for Algiers residential customers. Rather, the Advisors suggest, only generally, that the movement towards parity could occur through the FRP Rate Adjustment or a rider but do not specify what components would be taken into account in calculating that difference in future FRP proceedings. The testimony also suggests there be a limit of 4% on revenue adjustments for Algiers residential customers, but it is not clear how that limit would be calculated.[5] In addition, the Advisors' proposed plan seems likely to increase the disparity in residential rates among the Algiers and Legacy ENO residential customers, a result that conflicts with the Council's direction in Resolutions R-15-194 and R-17-504 to begin moving toward a single set of rates for all residential customers and is unsupported by any cost basis. In other words, there appears to be no valid reason to have different rates for Algiers and Legacy ENO residential customers indefinitely.

Q18. WHY DO YOU SAY THE ADVISORS' PROPOSED PLAN SEEMS LIKELY TO INCREASE THE DISPARITY?

A. The Advisors intend to apply a 4% cap on the future annual Algiers residential customers' FRP Rate Adjustment, as opposed to using the 4% cap only to address the current disparity in Algiers and Legacy ENO residential rates, as shown in the excerpts of the deposition transcript of Victor Prep, attached as Exhibit JBT-11. In other words, should an FRP Rate Adjustment call for a 5% increase in revenue from the entire residential class as a result of ENO incurring additional costs to provide and improve service, the Algiers residential customers would only receive a 4% increase and ENO Legacy residential customers would bear the 1% not borne by the Algiers residential customers in addition to their share of the 5% increase in revenue. The only exception the Advisors would permit for the cap is interim rate adjustment associated with the

[5] Direct Testimony of Victor Prep at 80-82.

NOPS non-fuel revenue requirement.[6] The Advisors do not explain why Algiers residential customers should receive the benefits of ENO's investment while being insulated from future cost increases in this manner, which would only serve to increase the disparity between Legacy ENO and Algiers residential customers, as opposed to narrowing the differential by mitigating only the base rate and assuming all future increases are applied equally to Legacy ENO and Algiers residential customers, as proposed by ENO. And, as I stated above, ENO is aware of no reason for treating the Algiers residential customers differently than the Legacy ENO customers on a forward-looking basis.

Q19. CCPUG WITNESS MR. BARON ARGUES THAT THE ARRT PLAN IS NOT REASONABLE BECAUSE IT "EXACERBATES THE SUBSIDIES PAID BY NON-RESIDENTIAL CUSTOMERS." DO YOU AGREE?

A. No, the ARRT Plan is reasonable and the exacerbation claim is not supported. Mr. Baron's analyses focus only on the base rate changes and ignores that the FAC and PPCACR Rider rates will be lower in the future because of the realignment of costs to base rates from the FAC and PPCACR Rider. In contrast, in Table 1 of my Revised Direct Testimony, I show that the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes are receiving substantial overall rate decreases when both base rate and rider changes are considered. Eventually, in his testimony, Mr. Baron admits that with the ARRT Plan there is gradual "movement"

6 *See* Exhibit JBT-11 at 16-20.

towards cost-based rates.[7] In fact, the AART plan is designed to move the overall revenue requirement of all classes, including the residential class, toward the cost of service, while observing the principle of gradualism to achieve that end.

VI. ALLOCATION OF PPA CAPACITY EXPENSES

Q20. MR. BARON COMPLAINS THAT THE RATIONALE SUPPORTING THE ENERGY ALLOCATION OF THE EAI WBL AND RIVER BEND 30% PPAS IS NO LONGER SUPPORTABLE BECAUSE OF THE SIGNIFICANT DECLINES IN NATURAL GAS PRICES. DO YOU AGREE?

A. No. Mr. Baron is trying to renegotiate a 2003 settlement approving a transaction that he believes is no longer as beneficial to his clients, large energy users. From 2003 until the end of 2008, large energy users captured a large portion of the energy savings resulting from these PPAs relative to then-current natural gas prices. A decline in natural gas prices does not invalidate the allocation methodology that was agreed upon at the time of the execution of those PPAs. Other factors that led to the Council's determination of the current cost allocation for those PPAs remain valid, and as such, it may not be in customers' interest to shift the capacity expenses associated with those PPAs to other customers as proposed by Mr. Baron.

[7] Direct Testimony of Stephen J. Baron at 21.

Q21. COULD ENO PURCHASE ENERGY IN THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO") ENERGY MARKET WITHOUT INCURRING CAPACITY EXPENSES AS MR. BARON SUGGESTS IN HIS TABLE 5?

A. No. These life-of-unit PPAs were executed in order to provide long-term capacity and energy to ENO customers. The MISO energy market is not intended, and should not be used, for this purpose. Load-serving entities, such as ENO, cannot participate in the MISO energy market without the existence of sufficient capacity to meet their expected peak load plus a reserve margin. As I understand it, the existence of sufficient capacity relies upon the undertaking of reasonable long-term resource planning by load serving entities. To meet their requirements, load-serving entities have to incur capacity costs associated with owned or controlled (PPA) generation capacity to prudently meet customers' capacity and energy needs over the long-term. Thus, Mr. Baron's comparison of local marginal price to fixed (capacity) and variable (fuel) PPA expenses is not meaningful, and the Council should disregard it.

Q22. THE ADVISORS HAVE RECOMMENDED THAT THE OVER- AND UNDER-COLLECTIONS ASSOCIATED WITH THE EAI WBL AND RIVER BEND 30% PPAS BE RECOVERED THROUGH THEIR PROPOSED PPCR RIDER RATHER THAN THE FAC. DOES THE COMPANY OPPOSE THAT RECOMMENDATION?

A. The Company's position is that the allocation of over- or under-collections of these capacity expenses should be consistent with the allocation of these capacity expenses in base rates. In a recent deposition, Advisors' witness, Mr. Prep seemed to concur in the general proposition that the method used to allocate costs among the classes in establishing base rates should be followed in riders that allocate those same categories of costs.[8] Accordingly, if the Council adopts ENO's proposed revenue allocation of these PPA capacity expenses based on energy, the over- and under-collections associated with these PPA capacity expenses should be included in the Fuel Adjustment Clause.

VII. RELIABILITY INCENTIVE MECHANISM PLAN

Q23. DID OTHER PARTIES OPPOSE THE RELIABILITY INCENTIVE MECHANISM ("RIM") PLAN?

A. Yes, multiple parties opposed the RIM Plan, including the Advisors. Nevertheless, ENO continues to recommend adoption of the RIM Plan. This 10.50% ROE corresponds to the recommended ROE of 10.75% discussed by Mr. Hevert, with an adjustment to calculate the electric base rate revenue requirement using a 10.50% ROE, for the reasons set forth in Ms. Stewart's and my Revised Direct Testimonies.

Q24. ADVISORS WITNESS MR. ROGERS MENTIONS THAT THE COUNCIL INTENDS TO ESTABLISH MINIMUM RELIABILITY PERFORMANCE STANDARDS IN DOCKET NO. UD-17-04. COULD THAT DOCKET SERVE AS AN ALTERNATIVE PROCEEDING IN WHICH TO ADDRESS THE PROPOSED RIM PLAN?

A. Yes, it could. ENO would be amenable to the Council setting ENO's electric ROE at 10.50% in this proceeding and directing that the details of a balanced financial incentive

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8 See Exhibit JBT-11 at 73-74.

and penalty mechanism that would permit ENO's ROE to adjust above 10.50% be determined in Docket No. UD-17-04, which ENO anticipates would be resolved prior to the resetting of rates through the FRP.

Q25. SOME PARTIES HAVE ARGUED THAT THERE SHOULD ONLY BE FINANCIAL PENALTIES FOR FAILING TO MEET MINIMUM RELIABILITY STANDARDS AND NO INCENTIVES FOR IMPROVING RELIABILITY. WHAT IS THE COMPANY'S POSITION?

A. The Company's position is that a mechanism tying reliability performance to a financial outcome should be symmetrical, that is, it should include both rewards and penalties, for the reasons stated in response to Q35 of my Revised Direct Testimony. Certainly, there should be a reasonable range representing the expected level of reliability performance, and if results fall within that range, no adjustment to rates is warranted. This range should consider the reliability performance of similarly-sized utilities within the same geographic region as ENO so as to be representative of the performance that ENO should be expected to achieve. If, however, parties feel that performance below the expected range should result in a penalty, then a financial value is being ascribed to reliability. Under that policy, reliability performance exceeding the expected range similarly has a value to customers, and the Company should be rewarded for achieving such reliability.

One policy issue to carefully consider is that any incentive mechanism, positive and negative, should be measured as to not encourage a focus on reliability spending that is misaligned with the overall goals of the Council. Furthermore, the mechanism should not produce equity returns below or above the range recommended by Mr. Hevert, but the range of equity returns produced should be determined based on additional factors so that reliability spending is not misaligned with the overall goals of the Council, as discussed in the response to Q34 of my Revised Direct Testimony.

VIII. CAPITAL STRUCTURE

Q26. WHAT WAS THE EQUITY RATIO THAT ENO INCLUDED IN ITS WEIGHTED AVERAGE COST OF CAPITAL CALCULATION IN THE INSTANT PROCEEDING?

A. As described in the Revised Direct Testimony of Mr. Orlando Todd, as now adopted by Ms. Beauchamp, ENO's equity ratio utilized to calculate its weighted-average cost of capital ("WACC") was 52.2%. This ratio was based on a projection of the capital structure at the end of 2018.

Q27. WHAT DOES THE ADVISORS' WITNESS, MR. WATSON, RECOMMEND WITH RESPECT TO ENO'S EQUITY RATIO?

A. Mr. Watson makes three recommendations with respect to ENO's equity ratio. My understanding of his recommendation is that, for the current cost of service revenue requirement, the WACC be based on "the lesser of: (a) ENO's actual equity ratio, and (b) 50%."[9] Additionally, Mr. Watson separately recommends that, for the purpose of "setting rates as a part of any FRP evaluations the Council may approve in the instant proceeding, the Council employ an equity ratio equal to the lesser of (a) ENO's then

[9] Direct Testimony of Byron S. Watson, CFA, CRRA at 55.

actual equity ratio properly excluding the effects of securitization bonds and cash, and (b) 50%."[10] Finally, Mr. Watson recommends "that in future base rate actions following the conclusion of any FRP the Council may approve in the instant proceeding, the Council consider whether Entergy Corp.'s equity ratio is probative considering Entergy Corp.'s then business characteristics (*i.e.*, considering the status of Entergy Corp.'s expected exit from merchant generation)."[11]

Q28. WHAT ARE THE REASONS HE PROVIDES IN SUPPORT OF THESE RECOMMENDATIONS WITH RESPECT TO ENO'S EQUITY RATIO?

A. Mr. Watson provides three reasons in support of his recommendation:

1) "[I]n past rate actions and investment proposals, a 50% equity ratio was accepted as reasonable and employed by ENO for cost forecasting purposes."

2) "ENO's actual December 31, 2018 equity ratio constitutes inappropriate double leverage."

3) "ENO's equity ratio is greater than that of the average of the other EOC's." [12]

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[10] *Id*. at 55-56.

[11] *Id*. at 56.

[12] *Id*. at 55.

Q29. PLEASE ADDRESS THE FIRST OF THESE REASONS, THAT PAST RATE ACTIONS AND INVESTMENT PROPOSALS SHOULD BE DETERMINATIVE OF THE EQUITY RATIO THAT SHOULD BE USED TO SET FUTURE RATES.

A. Mr. Watson points to the recovery of the non-fuel revenue requirement associated with Union Power Block 1 as one example supporting his reason, but the limitation of the equity ratio there occurred pursuant to a non-precedential agreement in principle.[13] He then points to a data request response in the Gas Infrastructure Rebuild Docket No. UD-07-02, which included an assumption that ENO's equity ratio was 50%. These are not instances where the Council determined in a contested proceeding that, for ratemaking purposes, ENO's equity ratio should be capped at 50%. Therefore, these examples do not support the Council imposing a cap on ENO's equity ratio in this proceeding. The Company's equity ratio should not be capped unless the Company agrees to such cap or there is a finding that ENO's capital structure is imprudent.

Q30. WOULD YOU ADDRESS THE SECOND REASON, REGARDING WHAT MR. WATSON REFERS TO AS "INAPPROPRIATE DOUBLE LEVERAGE?"[14]

A. Yes. I strongly disagree with Mr. Watson's position that ENO's capital structure used for ratemaking should consider anything other than the prudent and reasonable capital structure of ENO that is supportive of credit metrics that will provide ENO access to

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13 Resolution R-15-542 at Ordering Paragraph 3 ("The ratemaking provisions related to the recovery of costs associated with the Power Block 1 Purchase that are set forth in the Union Power Purchase AIP are just and reasonable.") *See also* Union Power Station Power Block 1 Purchase Agreement in Principle, Paragraph 12, Council Docket No. UD-15-01.

14 Direct Testimony of Byron S. Watson, CFA, CRRA at 55.

capital on a reasonable basis and result in just and reasonable rates for ENO and its customers. In my opinion, Mr. Watson's entire discussion around what he refers to as "double leverage" is a red herring that provides no basis for consideration in the context of this proceeding. I say this for two reasons.

The first reason is that ENO's rates should reflect those costs of ENO, and only ENO, that are prudent and necessary to provide service to its customers.[15] The capital structure of Entergy Corporation is not relevant to ENO's rates. In fact, Entergy Corporation's capital structure could possibly be relevant to ratemaking in this proceeding only in the event that it was determined to undermine the credit of ENO, and the Company has shown that the opposite is true. As noted in my Revised Direct Testimony, in its November 29, 2017 report on ENO, Standard and Poor's Financial Services LLC ("S&P") expressly stated that ENO's BBB+ rating was a direct result of it being a part of the Entergy Corporation group, and that otherwise, it would have a rating two notches lower, at the bottom range of the investment-grade scale.[16] From this, it is apparent that from a credit rating perspective that ENO and its customers benefit from the relationship with the Entergy Corporation group.

The second reason is that even Mr. Watson arrives at the conclusion that the use of Entergy Corporation's equity ratio would be unreasonable. He designs his argument in support of this position around the negative effects of "double leverage" by providing a

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15 *South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357, 368 (La. 1994) ("For the foregoing reasons, under the circumstances of this case, there having been no finding by the Commission that the actual capital structure of the utility resulted from unreasonable or imprudent investments, South Central Bell is entitled to have its rates fixed on the basis of its actual cost of capital under its existing capital structure.").

16 See Exhibit JBT-3.

hypothetical calculation comparing ENO's requested rates to those that would result from ENO having a capital structure similar to Entergy Corporation. He then admits that ENO maintaining an equity ratio consistent with that of Entergy Corporation's "reasonably might not be considered prudent."[17] While he does not indicate that this admission influences his analysis, his own testimony clearly shows that his concept of "double leverage" should not be considered, as he himself disregards the resulting impact as not being reasonable. He then states that the reasonable estimate of the effect of "double leverage" is based on the average non-ENO Entergy Operating Company ("EOC") equity ratio, which has no relationship to his concept of "double leverage" at all.

Q31. WOULD YOU ADDRESS THE THIRD REASON, REGARDING THE AVERAGE EQUITY RATIO OF THE OTHER EOCS?

A. Yes. First, I believe that the other EOCs' capital structures can serve as a guide to assessing the reasonableness of ENO's capital structure as long as differences among the companies are considered, such as number of customers and customer mix. However, the recommendation of the use of a hypothetical capital structure in lieu of the actual capital structure for ENO requires a finding that ENO's capital structure is imprudent or unreasonable. Despite his assertions to the contrary, the data assembled by Mr. Watson indicates that ENO's proposed capital structure is reasonable. As noted in his Table 4, the range of equity ratios is between 47.1% and 53.7% for the other EOCS.[18] ENO's

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17 Direct Testimony of Byron S. Watson, CF, CRRA at 54.

18 Direct Testimony of Byron S. Watson, CF, CRRA at 50.

projected equity ratio used for the purposes of the WACC calculation of 52.2% falls squarely within that range. Moreover, as mentioned previously by Mr. Hevert, ENO's proposed equity ratio falls within his proxy company average equity ratios range.[19]

Secondly, while the capitalization of the other EOCs may be used as a guide, one must consider whether there are justifications for a higher equity ratio based on the specific business factors of each company. Mr. Watson provided the average capital ratio of the other EOCs as a benchmark for ENO but has not provided any specific analysis of or explanation why the relatively small differential between ENO's proposed equity and the EOCs' average is inappropriate, especially given the significant differences in the risks faced by ENO as compared to ELL for example. On a relative basis, ENO is smaller than the other EOCs and must plan for larger debt issuances on a relative basis to have access to debt rates that are attractive. This means that its equity ratio may fluctuate over time, but ENO in conjunction with the Finance and Treasury groups executes on a plan to maintain ratios within a reasonable range.

Another consideration in the evaluation of the reasonableness of ENO's equity ratio is the effects of the Tax Cuts and Jobs Act ("TCJA") on the Company's credit metrics. In my Revised Direct Testimony, I described various effects of the TCJA on ENO's cash flows and other metrics. I also included Exhibits JBT-5 through JBT-7, which are credit rating agency reports describing the challenges for the industry as a result of the TCJA. Those reports also provide information on steps that utilities might take to remediate the negative effects of the TCJA. Those options are primarily based on

[19] Revised Direct Testimony of Robert B. Hevert at 81.

addressing cash flow concerns by implementing one or a combination of cash flow positive remedies which could include higher ROEs, higher equity ratios, and providing a supportive regulatory framework. It would be expected that each utility, and each EOC for that matter, would utilize different remedies to achieve that goal.

Q32. DO THE ADVISORS DISMISS THE COMPANY'S CONCERNS ABOUT THE EFFECTS OF THE TCJA?

A. They do, but their reasoning is unsupported. Advisors' witness Mr. Proctor addresses the effects of the TCJA in his Direct Testimony, noting that he believes that the effects on ENO would be "short-lived and immaterial."[20] Mr. Hevert's Rebuttal Testimony explains in detail why this is not the case. Further, in my opinion, Mr. Proctor's analysis that the loss of bonus depreciation and lower tax rates are neutral on a present value basis is unsound. As a result of the TCJA, utilities will not have as much cost-free capital because the tax rate is now lower and bonus depreciation has been lost. The suggestion that utilities could improve over the long-term does not address the issue that the TCJA creates now in the near-term cash flow concerns that need to be addressed to maintain credit metrics and ratings. The near term is what is important in this proceeding, and Mr. Proctor admits that there is a negative cash flow effects from the TCJA in the near term.[21]

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[20] Direct Testimony of James M. Proctor at 46.

[21] *Id*. at 43.

Q33. DO ANY OTHER PARTIES MAKE RECOMMENDATIONS WITH RESPECT TO ENO'S CAPITAL STRUCTURE?

A. Yes. CCPUG witness Mr. Kollen recommends that the capital structure used to determine the WACC should include a short-term debt component. His recommendation is not supported by the information provided during discovery. He alleges that ENO "has been a borrower on balance over the last three years."[22] As shown by ENO's response to data request CCPUG 2-31, which is attached hereto as Exhibit JBT-12, this is not actually the case. In 2016, ENO was a borrower from the Entergy Money Pool ("Money Pool") for nineteen days out of the year. In 2017, ENO was not a borrower at all. In 2018, ENO was a borrower for only 155 days but on average had a balance of over $6.6 million in lendings into the Money Pool.

Q34. DO YOU BELIEVE THAT SHORT-TERM BORROWINGS SHOULD BE INCLUDED IN ENO'S CAPITAL STRUCTURE FOR THE PURPOSE OF DETERMINING THE WEIGHTED AVERAGE COST OF CAPITAL?

A. No. The WACC calculation is intended to represent the cost of capital invested in rate base, the preponderance of which is long-term investments. The Money Pool is a convenient mechanism to make efficient use of cash by allowing borrowing between the EOCs, not a dependable source of financing for ENOs investments. Use of the Money Pool as a source of financing is predicated on the other EOCs having available cash on hand on a given date, which is in no way guaranteed. Mr. Kollen's recommendation

[22] Direct Testimony of Lane Kollen at 38.

suggests that ENO should consistently be in a position of borrowing from the Money Pool which is inconsistent with the intent and operation of the Money Pool. This would require that at all times the other EOCs provide guaranteed funding to ENO at the Money Pool rate. Again, the Money Pool is intended to be a convenience and to provide temporary credit support when excess funds are available for that purpose. It is not a standalone financing tool. The Money Pool interest rate is not intended to compensate the EOCs for that type of arrangement, and Mr. Kollen's recommendation distorts the underlying cost of the Money Pool as a financing tool. If the EOCs, or one of the other participants were required to maintain a lending balance at all times to make dollars available as Mr. Kollen's recommendation would require, then there would be a more significant cost to that as that party would need to make that part of a permanent financing arrangement, which would come at a cost well in excess of what is charged for Money Pool borrowings.

In addition, the capital structure used to determine the WACC should be representative of that which is expected to be in place during the rate effective period resulting from this rate case. As noted in ENO's response to data request CCPUG 1-5:

> ENO has been capable of issuing long-term debt on favorable terms as a result of its current credit ratings and current market conditions. As a result, ENO has not used short-term debt to support its investment in Rate Base in the recent past, and does not expect to do so going forward. Short-term credit facilities are intended to be used for emergent situations and potential liquidity events rather than for long-term cash management. Customers benefit from the availability of short-term debt in support of ENO's credit ratings for use in the event of major storms or other liquidity events. Those, however, tend to be temporary in nature and do not represent ENO's normal operations.

IX. APPROPRIATENESS OF PROPOSED RIDERS

Q35. PLEASE SUMMARIZE THE PARTIES' OPPOSITION TO ENO'S PROPOSED RIDERS.

A. The Advisors oppose the DGM, GIRP, AMI Charge, and the PPCACR Riders, which I refer to as the "Specific Project Riders." The Advisors also oppose the existing SSCO Rider, which I address separately from the Specific Project Riders due to its unique structure. The Advisors categorically argue that these rider mechanisms constitute inappropriate single-issue ratemaking, and are unnecessary because of the Advisors' proposed modifications to the proposed Electric and Gas FRPs, as I describe in Section IV of my Rebuttal Testimony. CCPUG opposes the DGM and GIRP Riders for different reasons, which I discuss below.

Q36. MR. WATSON RECOMMENDS THAT THE COUNCIL REJECT THE COMPANY'S PROPOSED USE OF RIDER MECHANISMS BECAUSE SUCH RIDERS INVOLVE INAPPROPRIATE SINGLE-ISSUE RATEMAKING. DO YOU AGREE?

A. No, I believe Mr. Watson's recommendation is overbroad. The Advisors are ignoring that ENO is proposing these riders in the context of Electric and Gas FRPs being in place and effective during the first three years of the riders' terms. In that way, the Council is able to consider all of the Company's costs on at least an annual basis, and inappropriate single-issue ratemaking is not an issue during that period.

Riders are an appropriate mechanism to address charges for unique or significant investments, and have historically been authorized by the Council even while FRPs have been in place for ENO. After the initial term of the FRPs, the benefits to customers from the capital projects associated with the Specific Project Riders and the need for and fairness of timely cost recovery, as discussed in my Revised Direct Testimony, justify the Specific Project Riders and outweigh concerns about single-issue ratemaking. As Advisors witness Mr. Rogers observed in his Direct Testimony, "riders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates" with their primary purpose being to reduce regulatory lag. [23]

Q37. HAVE THE ADVISORS DISPUTED YOUR ANALYSIS OF THE FACTORS SUPPORTING THE PROPOSED RIDERS?

A. Apart from the comments regarding Exhibit JBT-8, no, they haven't. In my Revised Direct Testimony, I focused on regulatory lag and its adverse effect on ENO's cash flow and capital reinvestment and the unfairness inherent in allowing customers to enjoy the contemporaneous benefits of various capital projects without permitting near contemporaneous cost recovery to the Company. As I mentioned above, the Advisors recognize that regulatory lag in the context of ENO's planned investment is a legitimate concern.

[23] Direct Testimony of Joseph W. Rogers, P.E. at 17-18.

Q38. WHAT COMMENTS DID THE ADVISORS MAKE WITH RESPECT TO EXHIBIT JBT-8?

A. Mr. Watson criticized my scenario in Exhibit JBT-8 as not fairly portraying regulatory lag. He complains that my scenario assumes that the first set of capital additions occurs on January 1, 2020 and that if the first set had occurred a day earlier, then rate recovery for it would have commenced five months earlier through the Combined Rate Case. Mr. Watson's complaints ignore the fact that ENO expects capital additions to occur every month associated with the GIRP, Grid Modernization, and the AMI project, including January 2020, and rate cases cannot be conducted nearly frequently enough to keep pace with this lag.

Mr. Watson also claims that there are regulatory lag benefits once an investment is included in base rates. Here again, his position does not take into account the contemplated level of future investment ENO plans to undertake that requires continuous capital additions over a multi-year period. The planned annual investment outpaces the recovery of that investment through depreciation several times over. The inability of depreciation expense or sales growth to cover the planned investment supports the recovery of these costs through the riders proposed by ENO. Otherwise, the Company will not be permitted a reasonable opportunity to earn its authorized return.

Q39. MR. WATSON ARGUES AT PAGE 76 OF HIS DIRECT TESTIMONY THAT THE COUNCIL SHOULD GIVE "STRONG WEIGHT" TO STATEMENTS ABOUT SINGLE-ISSUE RATEMAKING MADE BY ELL IN DISPUTE WITH THE LOUISIANA PUBLIC SERVICE COMMISSION ("LPSC"). IS THAT DISPUTE SIMILAR TO THE ISSUE RAISED BY ENO'S PROPOSED RIDERS?

A. No. Mr. Watson's testimony is offering a quotation without explaining to the Council the context in which the quote was made. In context, the entire sentence rebuts the LPSC's argument that it could have reduced ELL's base rates to reflect a decrease in a single cost recovered through base rates due to a Federal Energy Regulatory Commission order affecting that single cost without considering any other changes in costs recovered in base rates. By no means does this quote support a position that riders inherently include unreasonable single-issue ratemaking. Also, the Company did not contest an LPSC special order allowing the difference between the new level of the cost and the level of the cost embedded in base rates to be reflected in ELL's Fuel Adjustment Clause prospectively as of September 14, 2005. In short, there is no inconsistency between ELL's arguments in that dispute, and ENO's Specific Project Riders proposed in this proceeding. It is important to note that the recent renewal of ELL's FRP included several new riders. One rider is for the recovery of transmission investment on a forward-looking basis. A second rider was implemented to manage the crediting of excess ADIT balances, account for the resulting increases in rate base, as well as other adjustments as a result of the TCJA.

Q40. THE ADVISORS ARGUE THAT VARIATION AND CONTROL ARE FACTORS THAT SHOULD BE CONSIDERED IN DETERMINING WHETHER TO ALLOW RIDER RECOVERY. ARE THOSE FACTORS APPLICABLE IN THIS INSTANCE?

A. No. Both factors are not on point because the Specific Project Riders recover primarily the costs of capital projects and not expenses. The pertinent capital projects involve a lengthy period of increasing capital costs as they move through their construction phase, and, as shown in Exhibit JBT-8, ENO's base rates, even adjusted with the traditional FRP, will not allow ENO a reasonable opportunity to recover its total cost of service. Furthermore, the Council has directed ENO to incur certain costs (e.g., adding renewable resources to ENO's supply portfolio, DSM activities, reliability and grid modernization enhancements, AMI, etc.) to obtain benefits for customers. Further, as explained by Ms. Bourg, ENO is required by federal regulations to maintain and execute an integrity management program to identify and mitigate risks and threats to the safe operation of the gas distribution system, and the GIRP has been identified as the most effective mechanism for addressing these risks and threats. As explained by Ms. Zimmerer, in Resolution R-18-36, the Council indicated that now was the time for ENO to pursue grid modernization. In the case of the AMI project, the Council ordered ENO to accelerate the AMI project so that the project's costs increased by $4.4 million. With respect to the PPCACR Rider, the Company would recover the non-fuel costs of resources that the Council has found their acquisition or construction of serves the public interest and is prudent.

Q41. THE ADVISORS ASSERT THAT "RIDER COSTS THAT ARE TO AN EXTENT UNCERTAIN AT THE TIME RATES ARE SET IN A BASE RATE PROCEEDING WILL HAVE UNCERTAIN EFFECTS ON THE ULTIMATE RATES CHARGED TO CUSTOMER CLASSES AND MAY IMPACT RATE CLASSES DIFFERENTLY."[24] IS COST UNCERTAINTY A SIGNIFICANT ISSUE IN THE PROPOSED RIDERS?

A. No. With the proposed Electric and Gas AMI charges, the Council would approve a schedule the charges for the period August 2019 through December 31, 2034, so the proposed Electric and Gas AMI charges would not involve significant uncertainty. In the case of the DGM and the GIRP Riders, the uncertainty will be far less than that experienced with the Fuel Adjustment Clause or the Purchased Gas Adjustment Clause. The DGM and the GIRP Riders will be recovering increasing capital costs, as opposed to volatile commodity expenses, for which ENO can provide multi-year budget information. Also, the annual review procedures will permit the Council to determine whether these capital projects should continue. By contrast, the PPCACR Rider cannot be used without the Council's prior approval.

[24] Direct Testimony of Joseph W. Rogers, P.E. at 18.

Q42. THE ADVISORS ARGUE THAT "RIDERS TEND TO REDUCE RISK TO THE UTILITY AND PROVIDE AN EASIER PATH TO A UTILITY ACHIEVING ITS ALLOWED ROE."[25] IS THAT STATEMENT COMPLETE IN YOUR OPINION?

A. No. Mr. Hevert addresses the assertion that riders reduce the risk to the utility, and whether that should be a consideration factored into the calculation of a reasonable ROE. I would add that the riders also benefit customers. Although riders, which permit exact cost recovery, reduce certain risk to the utility, the reduction in risk lowers the level of capital costs that customers must bear, as I explained in my Revised Direct Testimony.

Also, I disagree that "such riders may provide an easier path to a utility achieving its ROE." That is an overstatement. Such riders may provide an easier path to a utility achieving its authorized ROE with respect to the capital costs subject to rider recovery, but there are many factors that can affect the earned ROE. Further, the riders generally ensure that the utility does not recover more than its authorized ROE with respect to such capital costs. Again, this is a benefit to customers. The question that must be considered is whether ENO is afforded a reasonable opportunity to achieve its authorized ROE in the absence of the proposed riders, or some other mechanism that will mitigate the regulatory lag that is the basis for their proposal. Riders are an important regulatory tool for the Council's use, and the incorrect notion that riders only benefit the utility should be rejected.

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25 *Id*. at 18-19.

Q43. THE ADVISORS WROTE THAT "WHILE THE REGULATOR MAY SEEK TO ALLOCATE COSTS IN RIDER MECHANISMS TO THE CUSTOMER CLASSES TO WHOM THE COSTS WOULD HAVE LIKELY BEEN ASSIGNED IF THEY HAD BEEN INCLUDED IN BASE RATES, THERE IS NO CERTAINTY THAT THE COSTS, IF KNOWN, MIGHT HAVE BEEN ALLOCATED MORE APPROPRIATELY IN A BASE RATE PROCEEDING WHERE ALL OF THE UTILITY'S COST CATEGORIES AND MAGNITUDE OF COSTS ARE CONSIDERED IN TOTAL."[26] PLEASE COMMENT.

A. If the Council approves the Specific Project Riders, the Company will collect the pertinent costs in accordance with the cost allocation selected by the Council.

Q44. THE ADVISORS OBSERVE THAT RIDERS "MAY ADD POTENTIAL UNDESIRED COMPLEXITY TO A RATEPAYER'S BILL." IS THAT OBSERVATION VALID?

A. No, it is not. The Company is not proposing that the Specific Project Riders must appear as three separate line items on customers' bills. The Company is willing to work with the Council and the Advisors to minimize any billing presentation concerns that the riders may cause.

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[26] *Id*. at 18.

Q45. MR. BAUDINO ARGUES THAT THE DGM AND GIRP RIDERS DO NOT CONTAIN PROCEDURES TO PROTECT CUSTOMERS LIKE THE FRPS. DO YOU AGREE?

A. No, Mr. Baudino is incorrect and ignores information in the Company's Revised Direct Testimony explaining the proposed riders. Company witness Ms. Bourg explained that the GIRP Rider would operate in conjunction with the annual Council reviews of GIRP, as recommended by the Advisors witness Mr. Rogers in Council Docket No. UD-07-02.[27] Similarly, the Company proposes that the DGM Rider operate in a regulatory framework in which the Council would approve the grid modernization projects to be recovered through the DGM Rider. Ms. Zimmerer explained in her Revised Direct Testimony that the Company is proposing a six-month approval process for all projects involving the submission of Project Design Packages, which will include a description of each proposed project, details on project design, engineering, expected benefits, estimated budgets, anticipated timelines, and other aspects of the project.[28] These regulatory proceedings augment the quarterly review periods in the DGM and GIRP Riders. Thus, these two investment programs will receive significant individual attention and will permit the Electric and Gas FRPs to focus on other aspects of ENO's operations.

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[27] Revised Direct Testimony of Michelle P. Bourg at 28.

[28] Revised Direct Testimony of Erica H. Zimmerer at 34-35. If the Council does not approve the DGM Rider, the Company would still recommend adoption of the grid modernization project review and approval process described by Ms. Zimmerer.

Q46. IN THE CONTEXT OF THE PROPOSED RIDERS, MR. BAUDINO TAKES ISSUE WITH YOUR STATEMENT REGARDING CONTEMPORANEOUS RECOVERY AND ARGUES THAT IT COULD ELIMINATE COUNCIL REVIEW AND INTERVENOR PARTICIPATION. ARE HIS CONCERNS JUSTIFIED?

A. No. ENO fully supports Council review of the utility's grid modernization and GIRP plans and intervenor participation, and the regulatory framework proposed by the Company allows this to occur. In these proceedings, the Company will be presenting its plans and expects to have constructive discussions about how these plans are designed to meet customers' needs. As a result, implementation of the riders proposed by ENO will increase transparency for the Council and intervenors, in addition to providing prospective information in these projects rather than relying on an after-the-fact review which would be the result of CCPUG's recommended approach. Only after receiving approval from the Council will the Company seek to recover these costs through the proposed riders, which will then be subject to Council review. This process worked in the context of the Gas Rebuild where insurance proceeds were used to fund capital projects as opposed to ENO's capital. This difference necessitates the GIRP Rider.

Q47. MR. WATSON PROPOSES THAT THE SSCO RIDER BE ELIMINATED AND THAT THE DEFERRED TAX BENEFITS INCLUDED IN THOSE RIDERS BE INCORPORATED INTO THE COMPANY'S ELECTRIC BASE RATE REVENUE REQUIREMENT. DO YOU AGREE WITH THIS PROPOSAL?

A. No. The SSCO Rider was implemented as a key component of a securitization that was undertaken in 2015 to finance ENO's Hurricane Isaac storm costs and to fully fund ENO's storm reserve. This securitization was undertaken pursuant to a settlement agreement between ENO and the Advisors – it was a unique and complex cost-recovery transaction designed to produce cost-savings for ENO's customers associated with these storm costs. Paragraph 47 of Resolution R-15-193 states that deferred income tax benefits will flow to customers through the SSCO Rider, and Paragraphs 49 through 53 contemplate no alteration of this Resolution as long as the storm recovery bonds are outstanding. The SSCO Rider was implemented to provide certain agreed-upon benefits to customers, through a rider mechanism so that customers and the Company would recognize those benefits on a dollar-for-dollar basis in the same manner as the SSCR Rider provides for the payment of the balance of the securitization bonds. The SSCR Rider and the SSCO Rider were always intended to work in concert to provide a cost-effective mechanism to capture the costs and credits of securitized storm recovery costs. Elimination of the SSCO Rider would inappropriately subject the crediting of the tax effects derived from the securitization to the bandwidth calculation of the FRP, and ultimately to unnecessary regulatory lag after the term of the Electric FRP, assuming one is approved as a result of this proceeding.

In addition, the value of ADIT underlying the SSCO Rider was an agreed-upon amount of ADIT related to the securitization. That agreed-upon ADIT included an amount for the casualty loss recognized on the storm damage done to the assets which were replaced as a result of the storm, and the ADIT on the new assets, both of which are a credit ADIT balance but which are included on the books of ENO. This agreed-upon ADIT amount also included a debit ADIT balance resulting from the fact that the proceeds from the securitization were treated as taxable revenue upon receipt. That debit balance is not on the books of ENO, and as such, would require a pro forma adjustment to include that debit in the applicable rate filings until 2036. The effect of that adjustment was not considered by Mr. Watson and would increase current period rate base by $6.1 million, and the revenue requirement by $0.7 million, consistent with the amounts currently included in the SSCO Rider. Failure to include these amounts in rate base would mean that ENO would not be made whole by moving the SSCO Rider into base rates and would be in violation of the agreement made when the securitization was approved. No evidence has been presented in support of why such a consequence is warranted, or what circumstances have changed such that the Council's rationale for approving the SSCO Rider in Resolution R-15-193 is no longer valid. Absent compelling evidence in this regard, it is unreasonable to modify the terms of the agreement pursuant to which the securitization was undertaken.

On balance, realigning the SSCO Rider into base rates would provide no appreciable benefit to customers or the Company, would be inconsistent with the

Council-approved order that provided for the execution of the securitization, and would add unnecessary complexity to future rate filings.

Q48. DID THE COMPANY DISCOVER ANY ERRORS IN ITS COST OF SERVICE STUDIES DURING ITS REVIEW OF MR. WATSON'S RECOMMENDATION?

A. Yes. The Company determined that certain SSCO ADIT credit amounts in Accounts 282111, 282112, 282533, and 282534 were not excluded from the Period II Electric Rate Base. The removal of SSCO ADIT credits in these accounts would result in an increase to rate base of $11.7 million.

In his recommended adjustment, Mr. Watson proposed to add back the amount to the balance of ADIT assuming the Company made the entry described above to remove it. Based upon the schedules that were included in the annual SSCO Rider filing in July 2018, Mr. Watson calculated $6,156,060 as the recommended decrease in rate base in the ENO Cost of Service ("COS") filing. There are several reasons why the SSCO ADIT adjustment amount that was not included in the ENO COS filing differs from the amount that Mr. Watson calculated. Mr. Watson's method uses a beginning/ending average to calculate ADIT, while the ENO COS uses end of period balances for ADIT. In addition, the July 2018 SSCO Rider ADIT for accounts 282111 and 282112 also includes a "Tax on Principle Adjustment." This is a rate making adjustment that is not included in ENO COS Filing. Furthermore, the July 2018 SSCO Rider ADIT assumes that year one is 2015, the year of Securitization. The actual Securitization ADIT in accounts 282111, 282112, 282533, and 282534 began in 2012, the year of the Hurricane Isaac Storm Costs.

This results in a three-year differential between the ADIT balances used to calculate Mr. Watson's amount and the actual ENO COS end of period balances for ADIT. Regardless, as described above, ENO failed to make the entry to remove the associated balance of ADIT. So, unless that correction is made, Mr. Watson's proposed adjustment would be to add back an amount which was never removed and should therefore not be included. If the Council directs ENO to make this adjustment in future filings, it should be based on the amounts agreed upon in the rider schedule, and not from the Company's books and records. Mr. Klutcher further discusses this concept of synchronization of rider revenues and expenses in the context of the FRP.

X. AMI CHARGES

Q49. WHICH PARTIES OPPOSE THE PROPOSED AMI CHARGES?

A. The Advisors and the AAE oppose the AMI Charges. The Advisors oppose the cost allocation inherent in the AMI Charges but seem to acknowledge ENO's concerns regarding regulatory lag with respect to the recovery of AMI-related costs net of savings. The AAE objects to AMI-related costs being recovered through a fixed charge and the inherent cost allocation.

Q50. DOES ENO STAND BY ITS ORIGINAL PROPOSAL REGARDING THE AMI CHARGES?

A. Yes. But, as I mentioned earlier, a Formula Rate Plan that permits forward-looking adjustments, as suggested by the Advisors, could serve as a substitute for the AMI Charges assuming other issues relative to the Formula Rate Plan can be resolved.

Q51. AAE WITNESS MR. BARNES ARGUES THAT A FIXED PER-CUSTOMER CHARGE IS UNREASONABLE. IS MR. BARNES CORRECT?

A. No. First, Mr. Barnes admits that there is nothing unusual with allocating metering and associated metering costs through a fixed monthly charge. Second, Mr. Barnes fails to acknowledge that the benefits from Consumption and Unaccounted for Energy Reductions flow directly to the customer based on each customer's individual usage through the Fuel Adjustment Charge. Therefore, to match this individual realization of benefits, which represent over 50% of the benefits of AMI, each customer individually should bear the costs associated with the infrastructure producing those benefits, which costs are fixed.

Q52. MR. BARNES CLAIMS IT IS "FUNDAMENTALLY UNFAIR" TO PAY FOR UNDEPRECIATED COST OF LEGACY METERS AND AMI INFRASTRUCTURE AT THE SAME TIME. DO YOU AGREE?

A. No. The Council has already decided that it is in the public interest for ENO to recover both sets of these costs at the same time. Moreover, there is nothing unfair or unusual about the Council's decision. In fact, such recovery happens whenever an asset that is not fully depreciated at the time of retirement is replaced. Generally, ENO recovers a return on the undepreciated cost of the retired asset and then later that recovery is augmented to include the recovery of the undepreciated cost itself over a specific period.

Q53. MR. BARNES ULTIMATELY PROPOSES THAT AMI-RELATED COSTS BE RECOVERED THROUGH A VOLUMETRIC CHARGE. HAS MR. BARNES PROVIDED ADEQUATE SUPPORT FOR SUCH A RATE DESIGN?

A. No, I do not believe he has. His arguments are centered around the premise that AMI meters are used to achieve incremental energy savings, and therefore the costs should be recovered on a variable basis to match. It is worth noting that all of Mr. Barnes's recommendations are myopically focused on adoption of a volumetric charge rather than the cost allocation that has been recommended by ENO, regardless of cost causation principles. With respect to the AMI Charges, Mr. Barnes himself recognizes that "it is true that metering and associated metering costs are typically recovered through fixed monthly charges."[29] He then goes on to a very labored argument of how traditional cost causation logic does not apply to advanced meters as compared to traditional meters. He conflates "causing" a cost with the customer having a choice about selecting an advanced meter. That does not follow the concept of cost causation. From a cost causation perspective, each customer requires a meter to receive service. The number of meters is almost directly tied to the number of customers that take service. Just as important, the

[29] Direct Testimony of Justin R. Barnes at 31.

usage of each customer has no effect on the cost of the meter, or the systems put in place to communicate with the meters or share the meter data with the customers. The vast preponderance of AMI-related costs is fixed. Therefore, Mr. Barnes's proposal to recover those costs on a fully volumetric basis is completely inconsistent with cost causation principles.

He claims a volumetric charge would protect lower income customers in the first paragraph of his response to Q45, but Mr. Barnes's recommendation is predicated on the assumption that all low-income customers are low usage customers. His assertions of the effects on low-income customers draw an incorrect correlation between income and usage, and as described in the Rebuttal Testimony of Dr. Faruqui.

In the next paragraph of his response to Q45, he claims that the shift of costs from low usage customers to high usage customers is justified because the savings associated with the energy savings driven by lower usage customers will provide greater benefits to higher usage customers. This is another very labored argument in an attempt to circumvent cost causation principles, and his testimony contains no evidence or analysis in support of that statement.

Q54. HAVE THE ADVISORS CORRECTLY QUANTIFIED THE AMOUNT OF NET EXPENSES ASSOCIATED WITH AMI TO BE INCLUDED IN THE ELECTRIC AND GAS REVENUE REQUIREMENTS, IF THEIR RECOMMENDATION IS ADOPTED?

A. No. ENO quantified the costs associated with AMI if the Advisors' recommendation were adopted in response to data request ADV 5-25, which is attached hereto as Exhibit

JBT-13, and recommends that the quantification contained in that response be used if the Advisors' recommendation regarding the recovery of AMI costs is adopted.

XI. NEW ORLEANS POWER STATION

Q55. IS THERE ANY OPPOSITION TO ENO RECOVERING THE FIRST YEAR REVENUE REQUIREMENT OF NOPS THROUGH AN INTERIM RATE ADJUSTMENT UNDER ENO'S PROPOSED ELECTRIC FRP?

A. No. But, there is an issue concerning the procedures to be followed in the first Electric FRP filing under the proposed Electric FRP.

Q56. WHAT IS THE ISSUE?

A. Advisors witness Mr. Prep proposed that the first-year revenue requirement of NOPS be included within the EFRP bandwidth calculation. This proposal seemed inconsistent with his concurrence on recovery of the first-year revenue requirement contemporaneous with NOPS entering service. In response to a data request, the Advisors clarified that the interim rate adjustment would occur without any bandwidth calculation. That data request, the Advisors' response to data request ENO 2-24, is attached hereto as Exhibit JBT-13.

Q57. IN THAT DATA REQUEST, THE ADVISORS STATED THAT IN EITHER THE 2020 OR 2021 ELECTRIC FRP EVALUATION REPORT, ENO SHOULD INCLUDE THE NOPS COSTS IN THE BANDWIDTH CALCULATION. DO YOU AGREE WITH THAT PROPOSAL?

A. No. The potential exists that bandwidth calculation may prevent ENO from recovering 100% of the NOPS costs. It would be illogical to permit 100% recovery of the NOPS costs in the interim rate adjustment but later reduce that recovery because of the FRP bandwidth mechanics. ENO's position is that the first-year revenue requirement should be reflected in its entirety in the FRP Rate Adjustment and any subsequent cost changes be subject to the bandwidth calculation.

Q58. DO OTHER PARTIES MAKE RECOMMENDATIONS REGARDING NOPS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Mr. Kollen actually makes three recommendations on behalf of the CCPUG regarding the recovery of the cost of NOPS regarding ROE, the depreciation rate, and the treatment of costs within the FRP mechanism. As noted in my Revised Direct Testimony, the Company has not sought to include the effects of the NOPS revenue requirements in rates resulting from this proceeding, but rather is only seeking to confirm the mechanism by which that recovery will ultimately be accomplished. As such, the Company proposes that the Council address the calculation of the first-year revenue requirement, including the appropriate depreciation rate for NOPS, in conjunction with the filing for cost recovery.

XII. OTHER RATEMAKING ISSUES

A. Prepaid Pension Asset

Q59. ADVISORS WITNESS MR. PROCTOR PROPOSES THAT THE PREPAID PENSION ASSET BE VALUED FOR RATE BASE USING ACTUAL ACCOUNTING DATA FOR CALENDAR YEAR 2018. DO YOU AGREE WITH HIS PROPOSAL?

A. No. The rate base valuation included in the Period II Cost of Service Studies should be used. Mr. Proctor is selecting arbitrarily one element of the cost of service to be updated with actual data and ignoring the others.

Q60. HAS THE COMPANY QUANTIFIED THE PREPAID PENSION ASSET USING ACTUAL ACCOUNTING DATA FOR CALENDAR YEAR 2018?

A. Yes. The Prepaid Pension Asset based on actual 2018 data on a Total Company basis would be $45,440,103, with the amount allocated to electric operations being $36,806,484 and the amount allocated to gas operations being $8,633,620.

Q61. HOW DO THOSE AMOUNTS COMPARE TO MR. PROCTOR'S ESTIMATES?

A. The amounts based on actual data set forth above are greater than Mr. Proctor's estimates, and Mr. Proctor's estimates would understate ENO's rate base.

B. Restricted Stock Incentive Plan

Q62. ADVISORS WITNESS MR. FERRIS RECOMMENDS THAT THE EXPENSES ASSOCIATED WITH THE RESTRICTED STOCK INCENTIVE PLAN SHOULD NOT BE RECOVERED IN RATES. WHAT IS THE RATIONALE FOR HIS RECOMMENDATION?

A. The rationale appears to be alleged similarities between the Restricted Stock Incentive Plan and certain executive incentive compensation expenses for which ENO agreed to not seek recovery in the 2010 Agreement in Principle, which resolved the Electric and Gas FRP Filings, which used a calendar year 2009 evaluation period. These expenses relate to the Long-term Incentive, Equity Awards, Restricted Share Awards, and Stock Option Incentive Compensation plans.

Q63. DO YOU AGREE WITH MR. FERRIS'S RECOMMENDATION?

A. No. Mr. Ferris has not demonstrated that ENO's compensation plans are unreasonable. Further, he is trying to rewrite the 2010 Agreement in Principle, which governed the recovery of executive incentive compensation, and he has not stated an independent basis for why the Restricted Stock Incentive Plan expenses should be disallowed.

Q64. IS THE PERTINENT PROVISION IN THE 2010 AGREEMENT IN PRINCIPLE PRECEDENTIAL?

A. No. The 2010 Agreement in Principle states that the provision was precedential only for the term of the FRP, which has lapsed. Nevertheless, in this proceeding, ENO has not sought recovery of certain executive incentive compensation expenses identified in the 2010 Agreement in Principle. The Company eliminated these expenses in Adjustment AJ07 in all four cost of service studies.

Q65. WAS THIS PROVISION OF THE 2010 AGREEMENT IN PRINCIPLE THE RESULT OF SETTLEMENT NEGOTIATIONS?

A. Yes. The Advisors at first proposed a broader disallowance of incentive compensation expenses. Originally, the Advisors had recommended the 100% disallowance of the expenses related to the Long-Term Incentive, Equity Awards, Restricted Share, Awards, and Stock Option Incentive Compensation plans and the 50% disallowance of the expenses related to Exempt Incentive, Management Incentive, Team Sharing Incentive, and Executive Annual Incentive plans.

Q66. DID THE ADVISORS SEEK TO DISALLOW THE RESTRICTED STOCK INCENTIVE PLAN EXPENSES IN CONJUNCTION WITH THE 2012 ELECTRIC AND GAS FRP FILINGS, WHICH USED THE EVALUATION PERIOD CALENDAR YEAR 2011?

A. No.

C. **2019 Adjustments**

Q67. CCPUG WITNESS MR. KOLLEN RECOMMENDS THAT ALL ADJUSTMENTS REFLECTING COST LEVELS EXPECTED IN 2019 BE REJECTED. WHAT REASONS DOES HE GIVE FOR HIS RECOMMENDATION?

A. He states two main reasons: (1) the adjustments violate the terms of Resolution R-17-504 and (2) only costs actually incurred are known and measurable.

Q68. DO YOU AGREE WITH HIS FIRST REASON?

A. No. Resolution R-17-504 contains no language prohibiting ENO from proposing adjustments to reflect cost levels expected in 2019. Moreover, the Code of the City of New Orleans authorizes a utility to make pro forma adjustments to reflect known and measurable changes. Specifically, the Code defines pro forma adjustments as "adjustments to Period I and Period II actual figures for known and measurable changes" and supports the Company's including pro forma adjustments to reflect cost levels in the year when the base rates from this proceeding will go into effect.

Q69. DO YOU AGREE WITH HIS SECOND REASON?

A. No. Mr. Kollen's second reason would prohibit all pro forma adjustments despite the Code's definition.

Q70. IN RESPONDING TO ENO'S TESTIMONY, MR. KOLLEN ARGUES ON PAGE 12 THAT "THE COMPANY'S PROPOSAL RESULTS IN A FUNDAMENTAL MISMATCH OF REVENUES AND COSTS." DOES HE IDENTIFY ANY MISMATCH?

A. No, he doesn't. Instead, he complains about the rates from this proceeding being effective August 1, 2019 when the pro forma adjustments consider cost levels as of December 31, 2019. Mr. Kollen, however, ignores that under the Company's proposal the rates from this proceeding will be in effect until September 2020. Thus, considering cost levels through December 31, 2019 is reasonable and, indeed, provides a much better matching of revenues and costs.

Q71. DO YOU AGREE WITH MR. KOLLEN'S QUANTIFICATION OF HIS RECOMMENDATION?

A. No. The Company and the Advisors have supported the inclusion of pro forma adjustments to include known and measurable capital projects closing to plant in service in 2019. If the Council were to accept this recommendation, however, Mr. Kollen's quantification is overstated. His calculations considered only Adjustment AJ14 for Plant Additions in the cost of service studies, which includes in rate base the expected plant additions and retirements through December 31, 2019. However, Adjustments AJ15 and AJ18 remove capital additions related to AMI and certain projects for which the Company was not seeking recovery through base rates, which were included in

Adjustment AJ14. Additionally, his quantification removes ADIT in Accounts 282111 and 282112 associated with plant additions expected in 2018.

D. <u>Storm Restoration Capital Costs</u>

Q72. MR. KOLLEN PROPOSES THAT CERTAIN STORM RESTORATION CAPITAL COSTS BE REMOVED FROM RATE BASE AND BE REIMBURSED FROM THE TWO STORM RESERVE AND COMPLAINS THAT ENO MADE AN "UNECONOMIC DECISION." SHOULD THE COUNCIL ADOPT THIS PROPOSAL?

A. No.

Q73. IS ENO'S PRACTICE OF NOT SEEKING REIMBURSEMENT FROM ITS STORM RESERVE FOR STORM RESTORATION CAPITAL COSTS NEW?

A. No. Although non-precedential, the Agreement in Principle resolving the 2008 rate case approved in Resolution R-09-136 provided that ENO would include its Hurricane Gustav and Ike storm restoration capital costs with carrying costs in rate base as of December 31, 2009 to be recovered through the Electric FRP authorized in that same resolution. ENO used this same approach with respect to its Tropical Storm Lee storm restoration capital costs, which ENO included in rate base in the FRP Evaluation Report for the calendar year 2011 evaluation period. ENO did this voluntarily as recovery of these capital costs would commence in the near future, and there were no objections by the Advisors to ENO's approach.

Q74. WAS THE COUNCIL AWARE THAT ENO TOOK THIS APPROACH WITH TROPICAL STORM LEE STORM RESTORATION CAPITAL COSTS?

A. Yes. The Accounting Advisors advised the Council of ENO's approach in their Review of Entergy New Orleans, Inc.'s Storm Reserve Fund Escrow Account dated August 10, 2012 pursuant to Resolution R-12-134, and the Council did not object.

Q75. WAS ENO'S NOT SEEKING REIMBURSEMENT FOR STORM RESTORATION CAPITAL COSTS "UNECONOMIC," AS MR. KOLLEN CONTENDS?

A. No. Mr. Kollen does not assign any value to having a large liquid storm reserve during storm season. However, based upon the difference in how the EOCs were evaluated by creditors and vendors in the wake of Hurricanes Gustav/Ike and Katrina/Rita, it is clear that there is value to such a storm reserve. This is apparent from two differences relative to the EOCs' circumstances after each set of storms, with the first being that the market had confidence that prudently-incurred storm costs would be recovered and the second being that the EOCs had well-funded storm reserves. Accordingly, ENO has not sought reimbursement for storm restoration capital costs in the past to preserve the value of its large liquid storm reserve where there have been alternatives available for timely capital cost recovery. In addition, ENO's proposed rates do not include a storm accrual to replenish the existing reserves. ENO has not proposed such a storm accrual based on the current use of the storm reserve balances for deferred operation and maintenance expense ("O&M") and not capital costs. If Mr. Kollen's recommendation were to be accepted, the storm reserve balances would be exhausted much more quickly than what can be expected by using those reserves to reimburse only deferred O&M with consequences ranging from restricted access to credit at a time when it is most needed to requiring an immediate replenishment of ENO's storm reserves.

Q76. MR. KOLLEN RECOMMENDS A REDUCTION OF $2.179 MILLION TO THE ELECTRIC REVENUE REQUIREMENT RELATED TO HIS PROPOSAL. DO YOU AGREE WITH HOW THAT AMOUNT WAS CALCULATED?

A. No. Aside from the reasons I previously identify regarding why this proposal is inappropriate, there are several issues with the calculation that would need to be corrected. First, Mr. Kollen assumes that the entire $16.7 million is related to electric plant in service and has been in service for one year. However, $178,000 of these storm restoration capital costs is in gas plant in service, which are depreciated at different rates. Second, the $16.7 million includes $3.2 million of storm removal costs that are recorded in Account 108. Mr. Kollen incorrectly calculated depreciation on these storm removal costs, which overstates the reduction he recommends to the revenue requirement. Third, Mr. Kollen assumes that all the costs were classified as distribution when in fact $2.7 million are classified as transmission and $0.245 million are classified as general plant, which results in the application of different depreciation rates. However, Mr. Kollen used the average electric distribution rate from the as-filed depreciation study. For the reasons I previously stated, the Company does not agree with Mr. Kollen's proposal that the $16.7 million in storm restoration capital costs be reimbursed from the storm reserves. If the Council were to agree with Mr. Kollen's recommendation, the proposed revenue requirement reduction would need to be corrected based on the discrepancies noted above.

E. <u>CCPUG's Proposed Extension of Amortization Periods and Depreciation Rates</u>

Q77. CCPUG WITNESS MR. KOLLEN MAKES SEVERAL RECOMMENDATIONS TO REDUCE THE RATES OF DEPRECIATION ON PLANT ASSETS AND TO EXTEND THE AMORTIZATION PERIODS ON REGULATORY ASSETS. DO YOU HAVE ANY COMMENTS ON THESE ADJUSTMENTS?

A. I do. First, I should note that ENO believes that assessment of the useful life of NOPS is more appropriately determined at the time the updated revenue requirements are submitted in order to include them in rates. Second, Messrs. Clayton and Breedlove address reasons why Mr. Kollen's recommendations with respect to the depreciation rates for plant are not supported by established depreciation rate calculations in his Rebuttal Testimony. I think it is also important to note, from a policy perspective, that while Mr. Kollen's recommendations may serve to reduce rates in the short term, in the long term they will ultimately increase the total cost to customers associated with the assets, as well as creating concerns around generational issues from a cost benefits perspective.

Mr. Kollen's recommendations will no doubt reduce depreciation and amortization expense collected in rates, but there is a balance that must be struck when setting those depreciation and amortization rates that have significant effects in rates over the long term. Reducing depreciation of plant assets, for example, while decreasing the collection of depreciation expense on an annual basis, also increases rate base which earns a return at the weighted average cost of capital for all remaining years. That means that on a nominal cash flow basis, customers will potentially pay significantly more for an asset than they might otherwise. Setting appropriate depreciation rates and amortization periods balances the annual rate effects as well as the long-term rate effects. Just as important is that it better aligns the recovery of the costs of those assets with the periods over which the customer receives the benefits from the use of those assets. Setting depreciation rates that are too low creates a significant risk that assets will be retired while having a substantial undepreciated balance to be recovered. When that occurs, future customers will be paying for the remaining recovery of that balance when the asset is no longer providing them service.

To compound this effect, that plant typically must be replaced by new plant to meet the same service needs of customers. When that happens, those future customers are left paying for both the new asset as well as the remaining balance on the retired plant. As is pointed out in Mr. Clayton's Rebuttal Testimony to Mr. Kollen's recommendations, this undesirable outcome becomes fairly likely to occur given the extremely low depreciation rates recommended by Mr. Kollen. Many of those same factors apply to Mr. Kollen's recommendations to extend the amortization periods of regulatory assets. For these reasons, I believe the Council should reject Mr. Kollen's recommendations regarding depreciable lives and amortization periods.

F. ADIT on Stranded Meters

Q78. DO YOU AGREE WITH THE ADVISORS' RECOMMENDATION THAT THE ADIT ASSOCIATED WITH STRANDED METERS TO BE REPLACED AS PART OF THE AMI PROJECT BE INCLUDED IN RATE BASE?

A. No, I do not. The Advisors' reading of the Agreement in Principle approved in Council Docket No. UD-16-04 ("AMI AIP") is unreasonable.

Q79. WHY DO YOU NOT AGREE?

A. The amortization provided for in the AMI AIP does not allow ENO to earn its full WACC on the unamortized net book value of the stranded meters over the course of the amortization. If the associated ADIT balance is included as an offset to rate base, it will provide a credit at the full WACC, while the assets whose depreciation generated that credit are being afforded a return at a lower rate of return. This is an illogical outcome that the Company's interpretation of the AMI AIP and the adjustments included in the cost of service avoid. Had the amortization included a return based on the full WACC, then there would be a basis to interpret the AMI AIP to require the inclusion of such ADIT in rate base. ENO's interpretation is also consistent with the Internal Revenue Service's normalization rules. Mr. Roberts provides testimony regarding the normalization rules applicability to the ADIT associated with the stranded meters.

Q80. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, at this time.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

JOSHUA THOMAS,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

JOSHUA THOMAS

Sworn to and

Subscribed Before Me

This 19th Day of March, 2019.

NOTARY PUBLIC

Alyssa A. Maurice
LA Bar #28388-LA Notary 68053
Notary Public in and for the
State of Louisiana
Commission Issued for Life

In the Matter of:

Application of Entergy New Orleans, LLC, et al

Victor Prep

March 14, 2019

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BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF)
ENTERGY NEW ORLEANS,)
LLC FOR A CHANGE IN) DOCKET NO. UD-18-07
ELECTRIC AND GAS)
RATES PURSUANT TO)
COUNCIL RESOLUTION)
R-15-194 AND)
R-17-504 AND FOR)
RELATED RELIEF)

* *

Deposition of VICTOR PREP, 8055 East Tufts Avenue, Suite 1250, Denver, Colorado 80237-2835, taken at the law offices of DENTONS, US LLP, located at 650 Poydras Street, Suite 2850, New Orleans, Louisiana 70130, commencing at 9:05 A.M., on Thursday, the 14th day of March, 2019.

APPEARANCES:

ENTERGY SERVICES, INC.
(By: Alyssa Maurice-Anderson, Esquire)
639 Loyola Avenue
Suite 2600
New Orleans, Louisiana 70113

- AND -

the case, we would probably bypass that revenue adjustment.

Q. If not a rider, what form would the adjustment for Algiers customers take?

A. It could be within the tariff. Without having written a specific adjustment procedure, I could say that it could be done within a tariff.

Q. How would that work?

A. I didn't -- And I didn't --

MR. REED:

Mr. Williams, I'm going to object to form. You're really calling for speculation since he did not in his testimony lay out the specifics of a rider, and what you're asking him to do essentially is to come up with a design for a rider here.

MR. WILLIAMS:

Well, that's fine.

EXAMINATION BY MR. WILLIAMS:

Q. I'm asking what you know, Mr. Prep.

A. And I am trying to be responsive, Mr. Williams.

Q. Sure.

A. In other words, I'm recommending that the form of that adjustment between legacy and Algiers residential customers take that which I had recommended in Exhibit 15. That form would be applied to succeeding revenue adjustments with the maximum. And that form could be explicit and done in proper form within a separate rider tariff or this tariff. I left that to be done in specific form when we got to a compliance filing or a settlement or whatever later.

Q. All right. Do you have any further thought on how the adjustment would be made if it was part of the formula rate plan process?

A. The formula rate plan process would provide a total residential revenue change and the total residential revenue change would be similar in application to the adjustment as what I have described in Exhibit 15.

Q. So would it stand apart from the other formula rate plan rate adjustments?

A. Are you -- When you say "other," you mean to the other rate classes other than residential?

Q. Let me try to be more concrete. I

mean, say there was a 5 percent increase called
for by the formula rate plan, not considering
this mitigation issue. How would the Algiers
revenue adjustment affect that increase for
Algiers customers and legacy residential
customers?
A. The Algiers customers would have, as
I recommended, a maximum of 4 percent. So if
it were a total 5 percent change, whatever the
revenue adjustment would be, the maximum of
4 percent would be applied to Algiers and the
total residential revenue change would be
affected with the remainder.
Q. So who would pay the remaining
5 percent that the Algiers customers didn't pay
-- I'm sorry -- the remaining 1 percent. I
posited a 5 percent increase. You said that
Algiers would be capped at 4 percent?
A. Well, again, using the same format
as Exhibit 15, we would have a revenue change,
a revenue level, and we would, as I
recommended, apply a maximum of 4 percent
increase in Algiers. The remaining dollars of
the revenue change would be implemented with
the legacy customers.

Q. Okay. So what if the FRP increase were only 2 percent? How would the Algiers customers be treated in that scenario?

A. The Algiers customers would be implemented with no more than 4 percent change, increase.

Q. So they'd get a larger increase than the FRP increase in that instance?

A. Than the -- You had suggested or -- a scenario where there would be a 2 percent residential increase?

Q. Yes.

A. Algiers customers would have, again as I recommended, a maximum of 4 percent and the remaining portion of the adjustment would apply to the legacy customers.

Q. So how would these adjustments be carried out mechanically in terms of tariff terms or FRP terms?

A. I think you've already asked that.

Q. Well, I asked that about the rider. I'm asking that about the FRP now.

A. The FRP would result in revenue adjustments per class and the residential revenue adjustment would take us to the

scenarios that you just posited.
Q. All right. If there were a FRP decrease adjustment, what would be the outcome for Algiers customers and legacy ENO customers in that scenario?
A. I would still posit a maximum 4 percent or recommend a maximum 4 percent increase in that annual revenue adjustment to Algiers and the balance be applied to legacy.
Q. So let me ask you this. If ENO's proposed rider for carrying out Algiers mitigation, if it was changed to be -- to impact only legacy ENO residential customers and Algiers residential customers, would that approach work for what you're trying to accomplish?
A. If -- Without seeing the -- If the final result or the exact format, if the concept and calculation as applied in Exhibit 15 were carried through between Algiers and legacy residential customers, then that apparently would accomplish my recommendation.
Q. Are you ready to continue?
A. Yes. Sorry.
Q. No problem.

Would Algiers customers bear their full share of the rate change related to NOPS?

A. All other things being equal, whatever that expression is, I would expect all residential customers would bear the share of NOPS. That was a provision, an exception in the application of the adjustment in my recommendation.

Q. So that wouldn't -- that particular rate change would not be subject to the 4 percent cap, for example?

A. Yes. I did make that provision, as I recall, in my testimony.

Q. What about changes in rates to recover advanced meter infrastructure investment? Would Algiers --

A. I made no other exception.

Q. Just NOPS? That's the only exception?

A. Yes.

Q. Let me ask you some questions about decoupling. I think that's on page 78 to 80 of your testimony. Let's see. Page 9.

MR. REED:

Did you say page 9?

MR. WILLIAMS:

Yes, sir. Well, bottom of page 8. Sorry.

EXAMINATION BY MR. WILLIAMS:

Q. You state there, I also recommend that the decoupling adjustment be calculated on an allocated basis similar to the advisors' decoupling proposal offered previously rather than on a revenue requirement by customer class as proposed by ENO. (As read.)

Can you give us more of a detailed explanation of what you mean by that on an allocated cost basis?

(Whereupon Ms. Tournillon enters the proceedings.)

THE WITNESS:

I believe in my additional testimony pages that you've mentioned earlier, I might have a further explanation, but I can summarize it to say that the recommended decoupling adjustment would be an allocation of revenue requirements similar to that done in the rate case here. So that that would differ in contrast to the results of the rate case what I recommend to be the maximum adjustments to bring Algiers' rates in coordination or in agreement or at the same level as legacy, then that would be a difference. They would have a percent different from what I would recommend be the maximum change.

Q. Right. And so once that change is made, the next time there's a formula rate plan adjustment, and there would be an Algiers cap of 4 percent, it would be 4 percent on top of the baseline that includes the NOPS increase; correct?

A. I believe NOPS will be part of the total residential rate, so I -- I mean, when you say "baseline," I'm not sure I understand.

Q. Well, the rate that 4 percent --

A. The rate --

Q. The rate that the next 4 percent is applied to?

A. The next 4 percent applies to.

Q. Okay.

A. Sorry.

Q. No problem.

Let me ask you another question about the formula rate plan. Testimony page

78. Lines 9 through 14, you discuss a provision for ENO proposing known and measurable cost adjustments in the formula rate plan; correct?

A. Yes.

Q. And so my question is -- this statement relates to costs -- could ENO also propose known and measurable adjustments to revenues?

A. So if there is a -- When I say "known and measurable," a revenue would change in respect to a -- or recovering a known and measurable cost or be correlated to a known and measurable cost. If there is a supportable basis to go beyond the FRP evaluation period in making adjustments other than to known and measurable costs that also include revenue, if there, in fact, is a supportable basis for that, or it relates to a cost adjustment and recovery of that, I would expect that could be -- that would be part of what the provision is that I recommended.

Q. Well, let me be a little more concrete. Could ENO make a known and measurable adjustment for the fact that energy efficiency would reduce demand, reduce sales in the period where the known and measurable adjustment is allowed?

A. You're -- That adjustment would be part of the decoupling aspect of the revenue adjustment in the FRP. That is, if I had a reduction in usage, if I had an impact on the allocation factors, they would all be included in the FRP evaluation. And the revenue that would be required and in an adjustment to that revenue that would be required to maintain the approved ROE, would all encompass that change that you described.

Q. Well, let me ask it this way. Let's say you had a thousand -- A utility had a thousand dollar revenue requirement for purposes of the FRP, but it expected its sales to be reduced by 1 percent due to energy efficiency during this known and measurable adjustment period, so it was going to be $10 less. Could it make an adjustment in its FRP or decoupling process to adjust rates to pick up that $10?

A. I understand your question to be directed to the months following the evaluation

Q. But although it may provide a complete picture, considering the exact cost recovery riders, you would agree, does not affect the Company's return ultimately?

A. The Company's return and the evaluation of is the process of providing the Company the opportunity with all of the tariffs and revenue and design and operation to achieve that rate of return. And it is not a set, but it is the opportunity to do that, and we evaluate the total costs and the total revenues in seeing how that, in fact, has been achieved for a test period. So I think that is substantially different from the process you've described.

Q. Have you reviewed how the result of your process in terms of class allocations compares to the result of the Company's process?

A. The Company only provided certain costs in the allocation. I don't think there is a direct comparison.

Q. Well, how different are your base rate allocations compared to the Company's, allocation of revenues?

A. A part of the picture, I can't recall exactly. I'm not sure. I'm not even sure what that comparison should be. It could be similar in one case and may be different in the next evaluation.
Q. That's not something you looked at specifically?
A. No.
Q. Riders have their own class allocation requirements; correct?
A. No. I think the allocation of costs is done in total and riders are part of the subsequent cost recovery process. And I consider the allocation process to be the first step and part of the total cost-of-service picture, cost recovery different.
Q. I mean, the riders -- Part of what the riders do is allocate the costs subject to the riders among various classes of ratepayers; correct?
A. Yeah. The rider tariffs are a cost-recovery mechanism. There're not an allocation mechanism.
Q. But they divide the recovery among various classes?

A. As we construct the riders.
Q. Right. They include a division of the rider cost among ratepayer classes?
A. For recovery purposes, yes.
Q. So are all your allocations consistent between the way classes are allocated costs in the class cost-of-service study and the way costs are distributed in the riders?
A. The riders -- The riders should recover costs consistent with the way those costs were allocated and revenue requirements result by the classes to which the riders would be applied.
Q. And you believe all your recommendations carried that out?
A. In general, I believe my recommendations were as I just expressed in my response. Could we be more specific?
Q. I'm just asking you. I mean, are there any exceptions where the way a class of cost that's ultimately recovered in a rider is allocated differently in the rider than it's allocated in the class cost-of-service study?
A. If it were applied the way the cost

recovery would be intended with the rider, it would be to recover costs that are allocated there. I don't see a need for exceptions.

Q. So your view is that all the costs in the rider should be allocated exactly the same way in the class cost-of-service study and in the rider design?

A. I think that's the intent of developing the riders, yes.

MR. WILLIAMS:

Let's mark this as Exhibit 1.

(Whereupon Exhibit 1 was marked for identification by the court reporter.)

EXAMINATION BY MR. WILLIAMS:

Q. The court reporter has handed to you what we've marked Deposition Exhibit 1.

A. Uh-huh (indicating affirmatively).

Q. And the top of this is Exhibit VP-9. Do you recognize that?

A. Yes.

Q. And at the bottom, we've included some variances that we've seen between Exhibit VP-9 and the ENO external working model with the advisors' changes. Are you familiar with this issue?

REPORTER'S CERTIFICATE

This certification is valid only for a transcript accompanied by my original signature and original required seal on this page.

I, Kathy Ellsworth Shaw, Certified Court Reporter in and for the State of Louisiana, as the officer before whom this testimony was taken, do hereby certify that VICTOR PREP, to whom oath was administered, after having been duly sworn by me upon authority of R.S. 37:2554, did testify as hereinabove set forth in the foregoing 118 pages; that this testimony was reported by me in stenotype reporting method, was prepared and transcribed by me or under my personal direction and supervision, and is a true and correct transcript to the best of my ability and understanding; that the transcript has been prepared in compliance with transcript format guidelines required by statute or by rules of the board, and that I am informed about the complete arrangement, financial or otherwise, with the person or entity making arrangements for deposition services; that I have acted in compliance with the prohibition on contractual relationships, as defined by Louisiana Code of Civil Procedure Article 1434 and in rules and advisory opinions of the board; that I have no actual knowledge of any prohibited employment or contractual relationship, direct or indirect, between a court reporting firm and any party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter; I am not related to counsel or to the parties herein, nor am I otherwise interested in the outcome of this matter.

____
KATHY ELLSWORTH SHAW, CCR, RPR
Certified Court Reporter
Curren Court Reporters
749 Aurora Avenue
Suite 4
Metairie, Louisiana 70005

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	)	
ENTERGY NEW ORLEANS, LLC	)	
FOR A CHANGE IN ELECTRIC AND	)	
GAS RATES PURSUANT TO COUNCIL	)	**DOCKET NO. UD-18-07**
RESOLUTIONS R-15-194 AND R-17-504	)	
AND FOR RELATED RELIEF	)	

EXHIBIT JBT-12
and
EXHIBIT JBT-13

HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED TO THE PARTIES IN DISCOVERY

MARCH 2019

ENTERGY NEW ORLEANS, LLC
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the Second Set of Data Requests
of Requesting Party: Crescent City Power
Users' Group

Question No.: CCPUG 2-31 Part No.: Addendum:

Question:

Please provide ENO's average daily balances of short-term debt from January 2016 through the most current month available in 2018. Please provide this information in an executable Excel spreadsheet.

Response:

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") under the terms of the provisions of the Official Protective Order adopted pursuant to Council Resolution R-07-432 relative to the disclosure of Protected Material and is being provided in accordance with the same.

See the HSPM attachment.

See also the Company's response to APC 2-8.

ENTERGY NEW ORLEANS, LLC.
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the Fifth Set of Data Requests
of Requesting Party: Advisors to the Council
of the City of New Orleans

Question No.: Advisors 5-25 Part No.: Addendum:

Question:

[redacted]

[redacted]

Question No.: Advisors 5-25

[redacted]

Response:

This request and information responsive to this request contains information that has been designated as Highly Sensitive Protected Material ("HSPM") under the terms of the provisions of the Official Protective Order adopted pursuant to Council Resolution R-07-432 relative to the disclosure of Protected Material and is being provided in accordance with the same.

The Company proposed the AMI customer charges as the mechanisms by which the Company would recover the incremental electric and gas investments in the AMI deployment presented in Council Docket UD-16-04 and the related incremental O&M costs and savings. Any incremental costs and savings within the per books amounts for Periods I and II were adjusted out of the base rates revenue requirements in the instant proceeding.

a.

i. See the attached revised HSPM Exhibits OT-1 and OT-2. The updates reflected in the attached exhibits include the updated capital additions, capital spending, O&M costs (including property taxes and customer education), as well as the updated O&M

savings.

ii.

1. Meter Reading expenses are recorded in FERC Account 902, found in OMCA902: 902 METER READING EXPENSE in ENO's cost of service revenue requirements.

2. Electric Meter Services employee expenses are recorded in FERC Accounts 580, 583, 584, 586, 587, 590, 593, 594, 596, 596100, 903001, 903002 and 920 found in OMD580: 580 OPER SUPVSN & ENGINEERING, OMD583: 583 OVERHEAD LINE EXP, OMD584: 584 UNDERGROUND LINE EXP, OMD586: 586 METER EXPENSES, OMD587: 587 CUST INSTALLATIONS EXP, OMD590: 590 MAINT SUPVSN & ENGINEERING, OMD593: 593 MAINT OF OVERHEAD LINES, OMD594: 594 MAINT OF UNDERGROUND LINES, OMD596NR: 596 MNT OF ST LGT & SIGNALS - NON-RDWY, 596100: Maint-Non-Roadwy Securty Lgtng, OMCA902: OMCA903: 903 CUSTOMER RECORDS & COLLECTION EXP (903001), OMCA903: 903 CUSTOMER RECORDS & COLLECTION EXP (903002) and OMAG920: 920 SALARIES, respectively, in ENO's cost of service revenue requirements.

   Gas Meter Services expenses are recorded in FERC Accounts 893, found in OMD893: 893 MAINTENANCE OF METERS & HOUSE REGULATORS in ENO's cost of service revenue requirements.

   Some Meter Service Employee labor was also charged to FERC Account 902, identified in ADV 5-25 a.ii.1. above.

3. Reduced Write-offs are recorded in FERC Accounts 904000 and 904001, found in OMCA904: 904 UNCOLLECTIBLE ACCOUNTS (904000) and OMCA904: 904 UNCOLLECTIBLE ACCOUNTS (904001), respectively, in ENO's cost of service revenue requirements.

iii. The expenses for Meter Reading, Meter Services and Write-offs included within Periods I and II per books are reflected in the tables below and as tab "Per Book Meter O&M Costs" in the file referenced in response to ADV 5-25 sub-part a. v. below. As noted in the footnotes in that tab, matching the Period II to the Period I costs for the Meter Services activities required different assumptions to be used in order to obtain an estimate of the forecasted per books Meter Service costs in Period II. The Period II costs may differ, but the Company cannot identify specifically by how much because the precise mapping of the individual employee costs in the forecast would be administratively burdensome. However, the actual savings would be reflected in per books amounts and would be "trued-up" in connection with the annual formula rate plan filings.

	Period 1	
O&M	**2017**	
Category	**Electric**	**Gas**
Meter Reading	1,377,490	697,585
Meter Services	995,453	289,719
Write-Offs	1,958,701	(162)

	Actuals	
	2017	
Capital	**Electric**	**Gas**
Meter Services	258,357	32,710

	Period 2	
O&M	**2018**	
Category	**Electric**	**Gas**
Meter Reading	1,390,119	682,221
Meter Services	2,248,563	190,831
Write-Offs	1,781,200	-

iv. The per books amounts shown in the tables above, in response to sub-part a. iii., were not adjusted in the Company's 2018 Base Rate Case Filing. The adjusted amounts that were included in the Company's 2018 Base Rate Case filing for Meter Reading, Meter Services and Write-offs are equal to the per book amounts shown above. No adjustments were included in the requested revenue requirements for base rates in the instant case since the AMI revenue requirements, including all of the incremental AMI costs (investments and savings), as well as the corresponding Operational O&M Benefits, were presented for recovery via the separate AMI Electric and Gas customer charges.

v. Included in the "Summary" tab of the attached file, "Adjustment to Include AMI in Cost of Service" are the adjustments amounts to the per books amounts for Meter Reading, Meter Services and Write-offs listed above to reflect the amount of Operational Benefits/savings expected to be realized by December 31, 2019 that are included in the revised HSPM Exhibits OT-1 and OT-2. Also included in the "Adjustments" file, are the adjustments to reflect the incremental AMI investments and expenses that are required to generate the level of savings by December 31, 2019 reflected in revised HSPM Exhibits OT-1 and OT-2.

In order to reflect the incremental AMI costs and related O&M savings in Meter Reading, Meter Services and Write-Offs, multiple steps are presented in the attached file using separate tabs. One of the first steps, shown on tabs "EL-Reverse AJ15" and "G-Reverse AJ15", is to reverse the effects of the proforma adjustment AJ15 in both the electric and gas cost of service studies filed in this proceeding in order to include the incremental AMI costs within the per books amounts. The next step shown is to compare the Per Book amount for the costs of Meter Reading, Meter Services and Write-Offs to the expected level of those costs at the time of the AMI application filing in the revised HSPM Exhibits OT-1 and OT-2, which resolves for difficulties in the specific identification of those costs in the test period as described in the footnotes to tab "Per Book Meter O&M Costs". The adjusted Per Book amount is then reduced by the expected level of savings in these activities due to the accelerated Meter Deployment in 2019. The third step is to include the expected level of incremental O&M costs, including the anticipated customer education costs in tab "AMI O&M Costs". The last step, calculated in tab "AMI Rate Base" is to include the rate base adjustments for the expected level of AMI investments through December 31, 2019. Since the reversal of AJ15 in the first step includes some level of investment, this last step compares the amount of rate base the components in the AJ15 reversal to the amounts presented in revised HSPM Exhibits OT-1 and OT-2 and calculates the adjustments necessary to reflect the level of investment presented in the revised HSPM Exhibits OT-1 and OT-2. The "Summary" tab is a summarized presentation of these adjustments by account, with the last column, "Total Adjustment Amount," reflecting the forecasted December 31, 2019 amount in each account.

vi. Since all of the operational savings (i.e., O&M savings) for AMI are tied directly to the deployment of AMI meters beginning in 2019, Period I and Period II per book amounts in the accounts listed in sub-part a.iii. do not include savings in the directly related to the reduction in costs as a result of the deployment of AMI equipment, as the AMI meters will be deployed beginning in early

2019. However, as the Company prepares for the deployment of AMI, some changes may already be reflected in the per books costs for the Meter Services function as affected employees begin to move to other positions and contract labor is used to provide meter service support instead. Also, all incremental AMI costs (capital and O&M) were adjusted out of the test periods in AJ-15. As a result, the incremental AMI costs net of the operational savings are included in the revenue requirements that are the basis of the Company's proposed AMI customer charges.

vii. See the attached file in response to ADV 5-25 sub-part a.v. above, tabs named "Adj El Op Benefits to OT-1" and "Adj Gas Op Benefits to OT-2".

b.

i. There are no differences between the O&M savings in AMI customer charges reflected in Exhibit JBT-9 work papers that support the requested AMI customer charges and the O&M savings included in the revised HSPM Exhibits OT-1 and OT-2 because the revenue requirements in these calculations reflect the same savings assumptions.

c. See the attached revised HSPM JAL-2 workpapers that reflect changes for the accelerated deployment, rate case requested ROE and cost of capital and tax rate changes.

d. See the following Excel file found in the below location on the Public CD (Revised) included with the Company's Application:

ENO PUBLIC_REV:\MFRs_COS\Workpapers\WP_Statement AA-2_REV-E.xlsx
ENO PUBLIC_REV:\MFRs_COS\Workpapers\WP_Statement AA-2_REV-G.xlsx

e. The amounts reflected in the entries in AJ15 do not completely reflect the total expected costs required to deploy AMI. Rather, the AMI related costs that were removed from the cost of service in the proforma AJ15 only reflect the costs incurred through December 31, 2017 and expected to be incurred through December 31, 2018. However, the Company provided an estimate of the adjustments that would be required to reflect the AMI deployment through December 31, 2019 in the Period II cost of service in the attached file provided in response to ADV 5-25 sub-part a.v. above, the "Summary" tab.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	)))))	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-24

Question:

Referencing page 76, lines 12-13 of Mr. Prep's testimony, please respond to the following:

a. Do the Advisors agree that recovery of the NOPS first-year revenue requirement should commence the first billing cycle of the month after NOPS enters commercial operation?

b. Please provide an illustration in electronic form with all cell formulae intact of and describe how the first-year revenue requirement of NOPS would be included within the EFRP bandwidth calculation.

Response:

a. Yes, for prudently-incurred costs, subject to the review as discussed in the response to part b.

b. Assuming NOPS enters commercial operation during 2020, the in-service rate adjustment would be based on the NOPS revenue requirement included in the updated NOPS filing made by ENO 75 days prior to the in-service date, reviewed by the Advisors and approved by the Council. The Advisors have proposed that pro-forma adjustments be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP. If the NOPS updated revenue requirement filing is not included in the proposed FRP filed in April 2020, with the FRP rate adjustment effective in September 2020, the NOPS in-service rate adjustment would be effective until NOPS costs are included in the bandwidth of the following FRP evaluation period revenue requirement and in the following FRP rate adjustment. The Advisors have no responsive workpapers and have not conducted the requested analysis.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	**DOCKET NO. UD-18-07**
GAS RATES PURSUANT TO COUNCIL	**)**	
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

ROBERT B. HEVERT

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Robert B. Hevert. I am employed by ScottMadden, Inc. as a Partner. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am filing this testimony (referred to throughout as my "Rebuttal Testimony") before the Council of the City of New Orleans ("City Council") on behalf of Entergy New Orleans, LLC. ("ENO" or "Company"), a wholly owned subsidiary of Entergy Corporation ("Entergy").

Q3. ARE YOU THE SAME ROBERT B. HEVERT WHO PREVIOUSLY SUBMITTED REVISED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the direct testimony of the following witnesses (collectively, "Opposing Witnesses") as their testimonies relate to the Company's Return on Equity ("ROE"):

- Messrs. James M. Proctor and Byron S. Watson, who testify on behalf of the Advisors to the City Council ("Advisors", collectively "Advisors' ROE Witnesses");
- Mr. Christopher C. Walters, who testifies on behalf of Air Products and Chemicals, Inc. ("Air Products"); and

- Mr. Richard A. Baudino, who testifies on behalf of the Crescent City Power Users Group ("CCPUG").

My Rebuttal Testimony also updates many of the analyses contained in my Revised Direct Testimony and provides several additional analyses developed in response to the Opposing Witnesses.

II. OVERVIEW OF TESTIMONY

Q5. PLEASE PROVIDE A SUMMARY OVERVIEW OF THE CONCLUSIONS AND RECOMMENDATIONS CONTAINED IN YOUR REBUTTAL TESTIMONY.

A. It is important to keep in mind that no one financial model is more reliable than others at all times and under all market conditions. At times, certain models' assumptions become incompatible with market conditions, and their results do not make practical sense. Consequently, we cannot always take model results as given, and assume their results are reasonable measures of the Cost of Equity. Rather, we should apply reasoned judgment in vetting model assumptions, and in assessing the reasonableness of their results. That judgment may lead to the conclusion that the emphasis applied to a particular method in a prior proceeding or under different market conditions is not appropriate in the current instance.

Regarding the Company's Cost of Equity, none of the analyses provided or positions taken by the Opposing Witnesses have caused me to revise my recommended range (10.25 percent to 11.25 percent), or my specific recommendation (10.75 percent). For example, certain of the Opposing Witnesses support their recommendations by reference to authorized ROEs, suggesting those returns have trended downward over time. If we consider individual cases over a relevant timeframe (rather than annual averages over long periods), there is no downward trend. There certainly is no basis to conclude ROEs in the range of 8.93 percent to 9.35 percent are supported by returns authorized for other vertically integrated electric utilities. Looking to all model results, and considering the quantitative and qualitative data presented throughout my Rebuttal Testimony, I continue to recommend an ROE in the range of 10.25 percent to 11.25 percent, with a point estimate of 10.75 percent.

As to the Company's capital structure, certain of the Opposing Witnesses recommend capitalization ratios that include more leverage (that is, contain more debt) than those in place at utility operating companies. They develop their recommendations based on reviews of parent company, not operating company capital structures. My Rebuttal Testimony explains that operating utilities' financing requirements are heavily influenced by the nature of their operations, including the long-lived nature of the assets required to provide utility service, and the need to access capital regardless of market conditions. The relevant measure of industry practice, therefore, is the financing practice at the operating company level, not the consolidated parent company level. As my Rebuttal Testimony also explains, Mr. Watson's proposed "double leverage" adjustment is not supported in theory or practice, and should not be considered in determining the Company's ratemaking capital structure.

Q6. PLEASE NOW PROVIDE AN OVERVIEW OF YOUR RESPONSE TO THE ROE RECOMMENDATIONS MADE BY THE OPPOSING WITNESSES.

A. In this proceeding, the Opposing Witnesses give considerable weight to the Discounted Cash Flow ("DCF") method, even though it produces ROE estimates in some cases more than 150 basis points below the returns authorized for other electric utilities.[1] For example, the Advisors' ROE Witnesses' recommendation of 8.93 percent is based on Mr. Watson's DCF analysis.[2] Mr. Walters set the low end of his recommended range (*i.e.*, 9.00 percent) by reference to his DCF model results,[3] and Mr. Baudino relies principally on his DCF results in arriving at his ROE recommendation.[4] Table 1 (below) summarizes the Opposing Witnesses' ROE recommendations.

Table 1:
Summary of ROE Recommendations

WITNESS	ROE RANGE		ROE RECOMMENDATION
	LOW	HIGH	
Mr. Watson (Advisors)	8.42%	8.93%	8.93%
Mr. Proctor (Advisors)	8.42%	8.93%	8.93%
Mr. Walters (Air Products)	9.00%	9.70%	9.35%
Mr. Baudino (CCPUG)	8.70%	9.35%	9.35%
Mr. Hevert (ENO)	10.25%	11.25%	10.75%

Because the Opposing Witnesses give considerable weight to their DCF-based results, it is not surprising that their recommendations fall well below currently authorized returns. As Chart 1 (below) demonstrates, since 2014 the Constant Growth

---

1 For example, Mr. Watson's median unadjusted two-step DCF ROE result is 8.09 percent, which is 170 basis points below the 9.79 percent average ROE authorized for vertically integrated electric utilities since 2014. *See* Direct Testimony of Byron S. Watson, at 44.

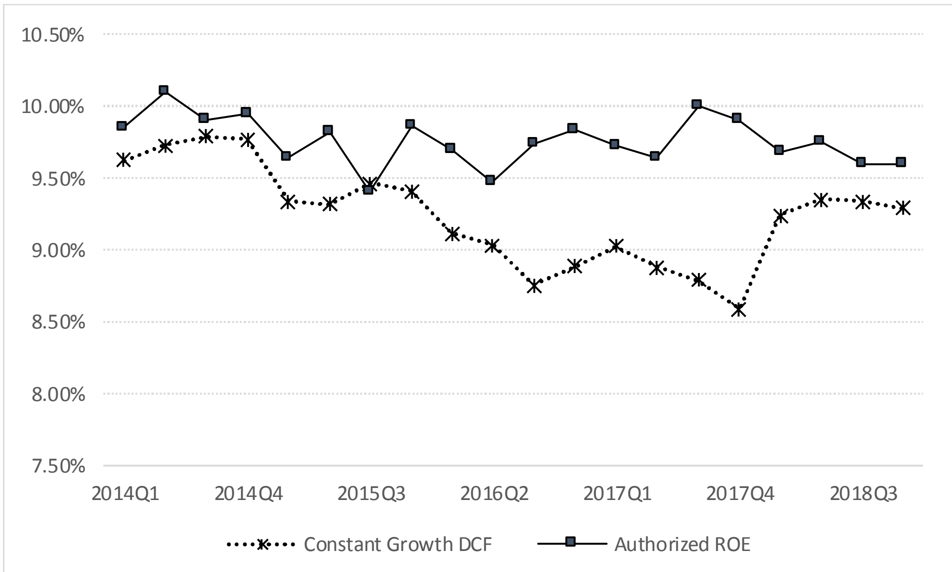
2 Direct Testimony of Byron S. Watson, at 44, 48–49; Direct Testimony of James M. Proctor, at 3.

3 Direct Testimony of Christopher C. Walters, at 49.

4 Direct Testimony of Richard A. Baudino, at 3.

DCF model has produced ROE estimates notably below the returns then authorized by regulatory commissions.

Chart 1: Authorized ROEs vs. DCF Estimates[5]



Given their common dependence on the DCF method, it also is not surprising that the Opposing Witnesses' recommendations generally fall within a narrow range. But the fact that their recommendations are similar does not mean their approaches and conclusions are reasonable. Even the highest of their recommendations (Mr. Walters' and Mr. Baudino's 9.35 percent ROE) is 44 basis points below the average return for vertically integrated electric utilities and is below all but eight ROEs authorized for vertically integrated electric utilities from 2014 through February 2019[6] (*see* Chart 2,

---

5 DCF results based on quarterly average stock prices, Earnings Per Share growth rates from Value Line, Zacks, and First Call; assumes Revised Proxy Group. Authorized ROEs are quarterly averages for vertically integrated electric utilities; source: S&P Global Market Intelligence. Please note that 2017 Q3 and 2016 Q2 included only one ROE decision.

6 The average authorized ROE for vertically integrated electric utilities (excluding limited issue riders) from January 1, 2014 to February 28, 2019 is 9.79 percent. 9.35 percent falls in the bottom 8th percentile of ROEs authorized for vertically integrated electric utilities since 2014.

below). The Advisors' ROE Witnesses 8.93 percent recommendation is below all authorized ROEs for a vertically integrated electric utility since at least 1980.

Chart 2: Vertically Integrated Authorized ROEs (2014 – 2019) [7]

As discussed throughout the balance of my Rebuttal Testimony, the Opposing Witnesses' recommendations cannot be supported by the reasonable application of financial models, nor can they be justified by current or expected market conditions. Rather, their recommendations are unduly low and if adopted, would increase ENO's regulatory and financial risk, diminish its ability to compete for capital, and would increase ENO's overall cost of capital, ultimately to the detriment of its customers.

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[7] Source: Regulatory Research Associates ("RRA"). Authorized ROEs for vertically integrated utilities from January 2014 through February 2019. ROEs authorized for generation-only (*i.e.*, "limited issue") rate riders are excluded.

Q7. IS THE PRINCIPAL USE OF A SINGLE METHOD COMMON IN FINANCIAL THEORY AND PRACTICE?

A. No, it is not. As Dr. Roger Morin notes:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.[8]

Professor Eugene Brigham recommends the CAPM, DCF, and Bond Yield Plus Risk Premium approaches:

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.[9]

Similarly, Dr. Morin (quoting, in part, Professor Stewart Myers), stated:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful

[8] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 428.

[9] *Ibid.*, at 430 – 431, citing Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

> information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.
>
> ***
>
> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies.[10]

Q8. HAVE OTHER REGULATORY COMMISSIONS RECOGNIZED THE IMPORTANCE OF CONSIDERING MULTIPLE METHODS IN SETTING AUTHORIZED ROES?

A. Yes. For example, in Baltimore Gas and Electric Company's 2016 rate case, the Maryland Public Service Commission discussed the importance of considering multiple analytical methods, given the complexity of determining the investor-required ROE:

> The ROE witnesses used various analyses to estimate the appropriate return on equity […] including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision. The subject is far too complex to reduce to a single mathematical formula. That conclusion is made apparent, in practice, by the fact that the

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[10] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 430–431.

> expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.[11]

In its November 15, 2018 *Order Directing Briefs,* the Federal Energy Regulatory Commission ("FERC") found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE".[12] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[13] As FERC explained, it is important to understand "how investors analyze and compare their investment opportunities."[14] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[15] Those methods include the CAPM and the Risk Premium method, which I have applied in this proceeding.

[11] *In the matter of the application of Baltimore Gas and Electric Company for adjustments to its electric and gas base rates, Public Service Commission of Maryland,* Case No. 9406, Order No. 87591, at 153. Citations omitted.

[12] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[13] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[14] *Ibid*., at para. 33.

[15] *Ibid*., at para. 35.

Q. HAVE OTHER STATE REGULATORY COMMISSIONS EXPRESSED CONCERN WITH DCF MODEL RESULTS?

A. Yes. For example, in its July 2017 *Order Accepting Stipulation* in which it authorized a 9.90 percent ROE for Duke Energy Carolinas, the North Carolina Utilities Commission ("NCUC") noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results."[16] Notably, the range found by the NCUC to be "unrealistically low" generally overlaps Messrs. Proctor's and Watson's recommended range.

Q9. ARE THERE ASPECTS OF THE DCF MODEL THAT MAY EXPLAIN WHY REGULATORY COMMISSIONS CURRENTLY DO NOT RELY PRINCIPALLY ON IT WHEN DETERMINING THE COST OF EQUITY?

A. Yes, the model's fundamental structure and underlying assumptions may become far removed from actual market conditions and financial practice. For example, the model assumes there will be no change, ever, in growth rates, dividend yields, Price/Earnings ratios, Market/Book ratios, or in the economic and market conditions that support those variables. Those assumptions, however, currently do not hold. For example, firms do not pay dividends at a constant dividend yield. Rather, continuous movements in stock

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[16] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, *In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, July 25, 2017.

prices, coupled with "sticky" dividend policies create continuous changes in dividend yields, contrary to the DCF model's assumptions.

The model's assumptions have become further removed from practice when current capital market conditions are influenced by monetary policy that is likely to change. Since the 2008/2009 financial crisis, Federal monetary policy has had a significant, intentional effect on capital markets, reducing interest rates and dampening equity market volatility. Those effects, however, will reverse with the "normalization" of monetary policy.[17] Consequently, neither the Federal Reserve's unconventional monetary policy initiatives nor the capital market conditions they supported will remain in place in perpetuity, as the Constant Growth DCF model requires. On that basis alone, we should be cautious about the weight given the DCF method.

[17] As the Federal Reserve explains: "The global financial crisis that began in 2007 had profound effects on the U.S. economy and other economies around the world. To support a return to the Federal Reserve's statutory goals of maximum employment and price stability, the Federal Open Market Committee ("FOMC") reduced short-term interest rates to nearly zero and held them at that exceptionally low level for seven years. The FOMC also undertook large-scale open-market purchases of longer-term U.S. Treasury securities and mortgage-backed securities to put downward pressure on longer-term interest rates. The term "normalization of monetary policy" refers to plans for returning both short-term interest rates and the Federal Reserve's securities holdings to more normal levels." *See* https://www.federalreserve.gov/faqs/what-does-federal-reserve-mean-when-it-talks-about-normalization-of-monetary-policy.htm.

Q10. ARE THERE STRUCTURAL REASONS WHY THE CONSTANT GROWTH DCF MODEL MAY NOT ALWAYS PROVIDE RELIABLE ROE ESTIMATES?

A. Yes, there are. As explained in my Revised Direct Testimony, the DCF model noted by the equation

$$k = \frac{D(1+g)}{P_0} + g$$ [18]

is derived from the longer-form present value formula

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}.$$

The model assumes investors use the present value structure to find the "intrinsic value" of common stock.[19] Consequently, the DCF approach will not produce accurate estimates of the market-required ROE if the market price diverges from the present value-based estimate of intrinsic value. That concern is not academic; differences between market prices and intrinsic valuations may arise when investors take short-term trading positions to hedge risk (*e.g.*, a "flight to safety"), to speculate (*e.g.*, momentum trades), or as temporary position to increase current income (*i.e.*, a "reach for yield").

We also know investors consider other methods, including relative valuation multiples – Price/Earnings, Market/Book, Enterprise Value/EBITDA[20] – in their buying and selling decisions. They do so because no single financial model produces the most accurate and reliable measure of value at all times and under all conditions. The implications of market prices diverging from DCF-based estimates of intrinsic value was

[18] As explained below, Mr. Watson's "Two-Step" DCF model essentially is the Constant Growth model, using a weighted average growth rate.

[19] Revised Direct Testimony of Robert B. Hevert, at 16–17.

[20] Earnings Before Interest, Taxes, Depreciation, and Amortization.

studied in an article published in the Journal of Applied Finance. That article, which focused on back-tests of the Constant Growth DCF model, found that even under "ideal" circumstances:

> … it is difficult to obtain good intrinsic value estimates in models stretching over lengthy periods of time. Shorter horizon models based on five or fewer years show more promise. Any model based on dividend streams of ten years or more, whether as a teaching tool or in practice, should be used with caution since they are likely to produce low-quality estimates.[21]

In short, because the DCF model is derived from a valuation model that assumes constancy in perpetuity, it is likely to produce less reliable ROE estimates when market conditions are non-constant, and when investor practice is to consider additional, alternative valuation methods. Both conditions currently hold.

Q11. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No, it is not. It is my view, however, that we should carefully consider the range of results the model produces. As discussed later in my Rebuttal Testimony, doing so fully supports my ROE range and recommendation.

[21] *See* P. McLemore, G. Woodward, and T. Zwirlein, *Back-tests of the Dividend Discount Model using Time-varying Cost of Equity*, Journal of Applied Finance, No. 2, 2015, at 19.

Q12. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- Section III – Responds to the Advisors' ROE Witnesses Mr. Proctor and Mr. Watson;
- Section IV – Responds to Air Products' witness Mr. Walters;
- Section V – Responds to CCPUG Witness Mr. Baudino;
- Section VI – Summarizes my updated analytical results; and
- Section VII – Provides my conclusions.

III. RESPONSE TO THE DIRECT TESTIMONIES OF MESSRS. PROCTOR AND WATSON REGARDING THE COMPANY'S COST OF EQUITY

Q13. PLEASE SUMMARIZE MESSRS. PROCTOR'S AND WATSON'S ROE ANALYSES AND RECOMMENDATIONS.

A. The Advisors' ROE Witnesses recommend an ROE of 8.93 percent, based on Mr. Watson's "Two-Step" DCF analysis, and supported by Mr. Proctor's CAPM analysis.[22] Mr. Watson's "Two-Step" DCF analysis produces a mean result of 8.09 percent, to which he adds 84 basis points, reflecting Mr. Proctor's "business risk" and flotation cost adjustment.[23] In their view, 8.93 percent is reasonable, in large measure because it falls within the range of Mr. Proctor's CAPM estimates.[24]

[22] Direct Testimony of James M. Proctor, at 16.

[23] Direct Testimony of Byron S. Watson, at 46–47.

[24] Direct Testimony of James M. Proctor, at 16; Direct Testimony of Byron S. Watson, at 49.

Q14. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH THE ADVISORS' ROE WITNESSES' ANALYSES AND CONCLUSIONS?

A. The principal areas in which I disagree with the Advisors' ROE Witnesses include: (1) their principal reliance on a single method to estimate the Company's Cost of Equity; (2) certain criteria used to select proxy companies; (3) Mr. Proctor's CAPM analysis, and the conclusions he draws from it; (4) Mr. Watson's Two-Step DCF analysis and the weight he gives to it; (5) the relevance of the Bond Yield Plus Risk Premium approach; and (6) the effect of certain business risks and considerations, including the Tax Cuts and Jobs Act ("TCJA"), the proposed Formula Rate Plan, and the effect of flotation costs on the Company's Cost of Equity. Beyond those methodological points, I strongly disagree that Messrs. Proctor's and Watson's ROE estimates, which range from 8.09 percent to 8.93 percent, are reasonable measures of the Company's Cost of Equity, regardless of how those estimates were derived.

In addition, although Mr. Watson points to the FERC to support his proposed Two-Step DCF method, FERC also has found that because DCF-based methods have produced unreliable results, it is important to apply multiple methods in determining the ROE. Those methods include the CAPM, Bond Yield Plus Risk Premium, and Expected Earnings approaches. When those methods are properly applied, it becomes apparent Mr. Watson's 8.09 percent (unadjusted) estimate, as well as his 8.93 percent recommendation, is unduly low.

Lastly, I strongly disagree with Mr. Watson's proposed "double leverage" adjustment to the Company's capital structure. As my Rebuttal Testimony explains, Mr. Watsons' proposal is internally inconsistent, counter to basic financial theory, removed from regulatory practice, and would have the counterproductive effect of increasing risks to investors and costs to ratepayers.

A. Unreasonableness of the Advisors' ROE Witnesses' Recommendation

Q15. AS A GENERAL MATTER, IS THE 8.09 PERCENT BASE ROE RECOMMENDATION, OR EVEN THE 8.93 PERCENT ADJUSTED RECOMMENDATION, A REASONABLE ESTIMATE OF THE COMPANY'S COST OF EQUITY?

A. No, it is not. Putting aside the many methodological issues discussed below, there simply is no basis to conclude equity investors would be willing to commit their capital for the opportunity to earn an 8.93 percent "risk-adjusted" return. Mr. Watson's unadjusted 8.09 percent ROE estimate is even less probable. Even their 8.93 percent "risk-adjusted" estimate is below every return authorized for a vertically integrated electric utility since at least 1980.[25]

The significant difference between the Advisors' ROE Witnesses' recommendation and the returns available to other utilities raises very practical concerns. The Company competes with other entities, including utilities, for the long-term capital needed to provide utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry levels, and another whose

[25] Source: S&P Global Market Intelligence. *See* Chart 2 above. I note that in UD-16-02, the Company's application for approval to construct the New Orleans Power Station, the Advisors' witness in that proceeding (Mr. Watson), noted that "9.75 percent is in line with ROEs recently set by retail regulators". *See* Docket No. UD-16-02 *Resolution and Order Regarding the Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery, and Timely Relief*, Resolution R-18-65, March 8, 2018, at 184.

authorized return more closely aligns with those available to other utilities, investors will choose the latter. Because authorized returns are publicly available,[26] it is reasonable to conclude that data is reflected, at least to some degree, in investors' return expectations and requirements.

Further, although they discuss credit ratings as a measure of business risk, the implications of an authorized return so far removed from industry norms are considerable. Putting aside the cash flow effects of an unduly low ROE, the increase in perceived regulatory and business risk would be significant. As Standard & Poor's ("S&P") explains, the regulatory regime is one of the most important factors in its rating analyses:

> For a regulated utility company, the regulatory regime in which it operates will influence its performance in profound ways. As such, Standard & Poor's Ratings Services' regulatory advantage assessment - - which informs both our business and financial risk scores - - is one of the most important factors in our credit analysis of regulated utilities.[27]

As S&P also explains, regulatory advantage is "the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[28] S&P further notes that:

> The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing transparency,

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[26] *See, for example*, American Electric Power Company, Inc., SEC Form 10-K for the year ended December 31, 2017, at 4; Entergy Corporation., SEC Form 10-K for the year ended December 31, 2017, at 31; WEC Energy Group, Inc., SEC Form 10-K for the year ended December 31, 2017, at 139–143; Xcel Energy, Inc., SEC Form 10-K for the year ended December 31, 2017, at 131–136.

[27] Standard & Poor's Ratings Services, *How Regulatory Advantage Scores Can Affect Ratings On Regulated Utilities*, April 23, 2015, at 2.

[28] S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, August 10, 2016, at 2.

> predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early 20th century) and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.[29]

Among S&P's principal considerations in assessing regulatory advantage is "regulatory stability", which includes three subfactors:

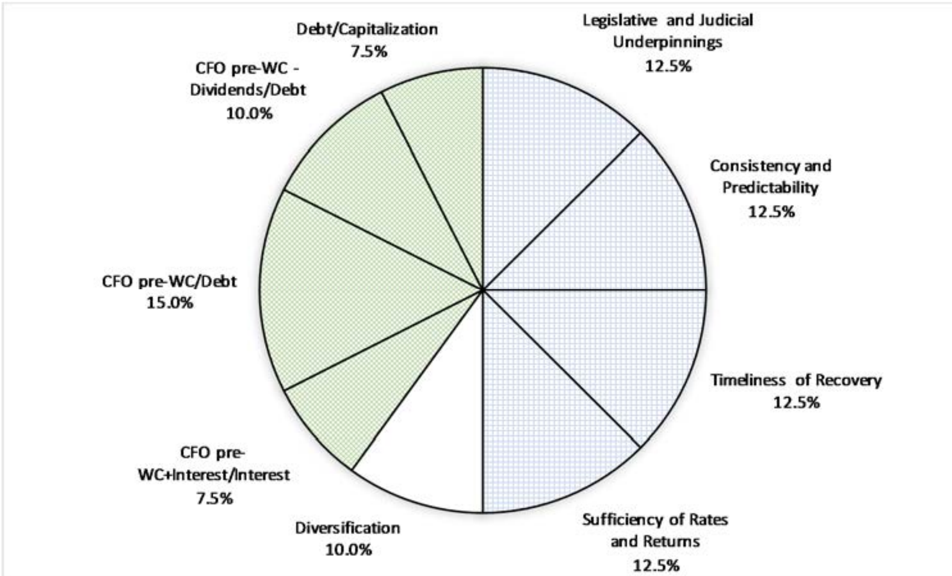
- Transparency of the key components of the rate setting and how these are assessed;
- Predictability that lowers uncertainty for the utility and its stakeholders; and
- Consistency in the regulatory framework over time.[30]

In a similar fashion, Moody's explains that its ratings are based on assessments of multiple factors, 50.00 percent of which relate to the nature of regulation. Even if we consider cash flow-related metrics, in aggregate those factors are given 40.00 percent weight (*see* Chart 3, below).

[29] *Ibid*.

[30] *Ibid.*

Chart 3: Moody's Ratings Criteria[31]



In summary, although the Advisors' ROE Witnesses discuss credit ratings as a measure of equity risk, they do not discuss the implications of their recommendations for the Company's credit profile.[32] In my view, if the City Council were to adopt the Advisors' ROE Witnesses' recommendation, investors would assess a heightened degree of regulatory risk, and would require higher returns for that risk, to the long-term detriment of customers. That is especially the case, and it is especially concerning, given the Company's below investment grade rating from Moody's.

Regardless of its derivation, I do not believe the Advisors' ROE Witnesses' 8.93 percent recommendation meets *Hope* and *Bluefield* "financial integrity", "comparable risk", "capital attraction" and "end result" standards.[33] The Company's below investment grade from Moody's distinguishes it from others in Mr. Proctor's (and,

31 Moody's Investors Service, *Regulated Electric and Gas Utilities*, June 23, 2017, at 4.

32 I address certain cash flow-related credit metrics later in my Rebuttal Testimony.

33 *See* Revised Direct Testimony Robert B. Hevert, at 8–11.

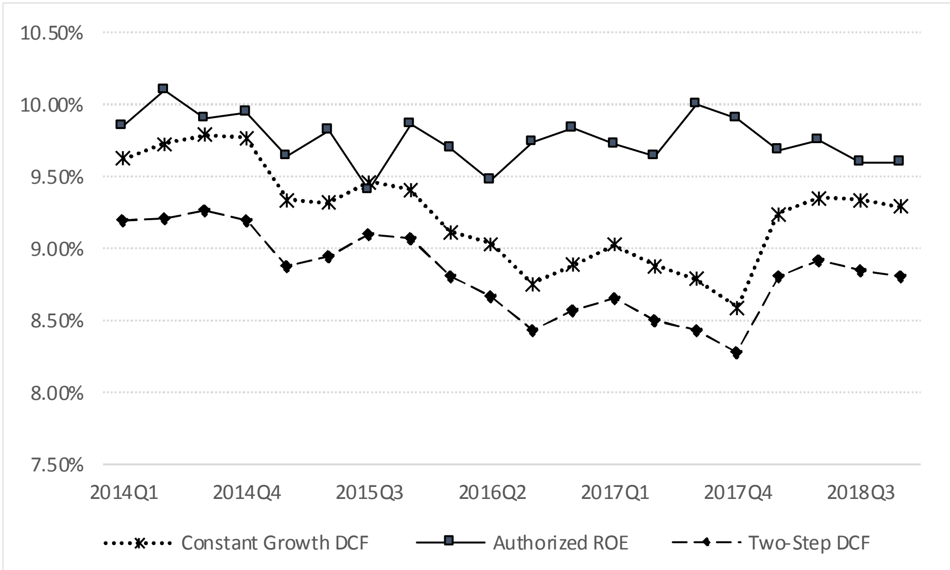
therefore, Mr. Watson's) proxy group. If credit ratings were proper measures of equity risk, there would be no reasonable means of reconciling a below investment grade rating with an ROE so far below those available to other electric and natural gas utilities, as the *Hope* and *Bluefield* standards require.

B. Principal Reliance on a Single Method

Q16. SHOULD A SINGLE METHOD, IN THIS CASE THE TWO-STAGE DCF MODEL, BE GIVEN PRINCIPAL WEIGHT IN SETTING THE COMPANY'S RETURN ON EQUITY?

A. No, it should not. As explained in Section II, doing so is inconsistent with finance theory and practice, as well as with decisions reached by regulatory commissions over the past several years. As Chart 1 (above) demonstrates, since 2014 the Constant Growth DCF model has produced ROE estimates consistently and meaningfully below returns then-authorized by regulatory commissions. Chart 4 (below) replicates Chart 1 and includes the results of FERC's two-step DCF method.

Chart 4: Authorized ROEs vs Constant Growth and Two-Step DCF Estimates[34]



Q17. LASTLY, WHAT IS YOUR RESPONSE TO MR. PROCTOR'S OBSERVATION REGARDING THE RANGE OF YOUR ANALYTICAL RESULTS?

A. Table No. 2 to Mr. Proctor's testimony (at page 49) provides the results of my three methods, which run from a low of 8.37 percent to a high of 12.28 percent, a range of 391 basis points. Although Mr. Proctor is concerned with that variability, Mr. Watson's "two-step" DCF results span from a low of 5.74 percent to a high of 10.64 percent,[35] a range of 490 basis points. That is, the 391-basis point range that concerns Mr. Proctor[36] is 99 basis points less than Mr. Watson's range. If my range of results is a "concern" for Mr. Proctor, it seems that concern would extend to Mr. Watson's results.

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34 DCF results based on quarterly average stock prices, Earnings Per Share growth rates from Value Line, Zacks, and First Call; assumes Revised Proxy Group. Authorized ROEs are quarterly averages for vertically integrated electric utilities; source: S&P Global Market Intelligence. Please note that 2017 Q3 and 2016 Q2 included only one ROE decision.

35 Exhibit No.__(BSW-4), Page 1.

36 Direct Testimony of James M. Proctor, at 48–49. Please note that Mr. Proctor's Table No. 2 includes the results of my three analyses, whereas Mr. Watson's wider range is attributable to a single method.

C. Proxy Group Selection

Q18. BEFORE RESPONDING TO MR. WATSON'S DISCUSSION OF INDIVIDUAL PROXY COMPANIES, DOES THE DIFFERENCE IN YOUR RESPECTIVE PROXY GROUPS EXPLAIN THE DIFFERENCE IN YOUR ROE RECOMMENDATIONS?

A. No, it does not. Although the Advisors' ROE Witnesses' recommendation is unduly low, the composition of their proxy group is not the principal reason for that result. I also appreciate that analysts may have reasonable differences in screening criteria, and how those criteria are applied. Consequently, many of the analyses discussed below are based on the Advisors' ROE Witnesses' respective proxy groups.

That said, Messrs. Proctor and Watson bring up certain points, including their focus on credit ratings as a screening criterion and a direct measure of equity risk, that affect other aspects of their conclusions. In particular, they argue their recommendation is reasonable by reference to their proxy group's average credit rating (BBB+).[37] Their use of credit ratings in that fashion raises three concerns.

First, credit notches within the investment grade rating category are not direct measures of differences in equity risk. Second, if the Company is no less risky than its peers, as Mr. Proctor's reference to S&P's credit ratings suggests, there is no reason why its ROE should be 80 basis points (or more) below the returns available to other, similarly rated utilities. Not only would that result be contrary to the *Hope* and *Bluefield* "comparable risk" standard, it would be inconsistent with the risk/return relationship integral to the one method Mr. Proctor applied, the Capital Asset Pricing Model. Lastly,

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[37] Direct Testimony of James M. Proctor, at 27–28; Direct Testimony of Byron S. Watson, at 26, Exhibit No.__(BSW-4), at page 5.

the Company's below investment grade rating from Moody's (1) distinguishes it from all other companies in Mr. Watson's proxy group, (2) supports my approach to screening proxy companies based on investment grade credit ratings, and (3) argues for an ROE above, not significantly below, its peers.

Q19. HOW DOES MR. WATSON USE CREDIT RATINGS AS A SCREENING CRITERION, AND HOW DOES HIS APPROACH DIFFER FROM YOURS?

A. Mr. Watson's screening criteria require proxy companies to have an issuer credit rating (from Standard & Poor's) within one "notch" of the Company's BBB+ rating.[38] Mr. Watson suggests "…credit ratings, as generated by companies such as Moody's Investors Service ("Moody's") and Standard & Poor's Financial Services LLC Rating's Direct ("S&P") seek to score companies such as ENO and other utilities as to their risks on a consistent and comparable scale."[39] He concludes that "…when identifying companies having corresponding risks and uncertainties as has ENO, comparable issuer credit ratings are an appropriate metric for corresponding risks."[40]

As Mr. Watson points out, my approach is different; I require proxy companies to have investment grade credit ratings, regardless of whether those ratings are within one "notch" of the subject company. I do so for two reasons. First, utilities, including Mr. Watson's proxy companies, tend to have high proportions of institutional ownership.[41] In

38 Direct Testimony of Byron S. Watson, at 26–27.

39 *Ibid*., at 25.

40 *Ibid*.

41 Source: Bloomberg Professional.

my experience, investment guidelines for institutional investors focus on investment grade entities, not entities within one notch of a given company. Because institutional investors own large percentages of utility equity securities, it is appropriate to reflect their investment criteria in our screening process.

Second, much like Mr. Watson, Mr. Proctor argues the credit rating screen "is appropriate because such screening will allow the Council useful information regarding the required returns on companies having comparable credit risks to that of ENO."[42] I disagree with the premise that differences in credit ratings are direct measures of differences in risks faced by equity investors. As discussed above, from an equity investor's perspective the critical issue is whether the subject company is above or below investment grade.

Lastly, neither Mr. Proctor nor Mr. Watson adequately reflect the Company's below investment grade credit rating (from Moody's). Although Mr. Watson acknowledges the Ba1 rating Moody's assigns the Company, he seems to discount its importance, noting that but for the Company's "small and concentrated service territory in a low-lying coastal region", the Company would have been rated "A2".[43]

Q20. WHY DO YOU BELIEVE DIFFERENCES IN INVESTMENT GRADE RATINGS ARE NOT DIRECT MEASURES OF EQUITY RISK?

A. First, credit ratings are opinions regarding the subject company's capacity to pay its financial obligations as they come due and payable. As S&P notes:

> An S&P Global Ratings issuer credit rating is a forward-looking opinion about an obligor's overall creditworthiness. This opinion

[42] Direct Testimony of James M. Proctor, at 27.

[43] Direct Testimony of Byron S. Watson, at 25.

> focuses on the obligor's capacity and willingness to meet its financial commitments as they come due.[44]

Credit ratings therefore speak to overall creditworthiness from the perspective of debtholders, who are promised a series of specified coupon payments over the term of the bond, and who have a contractual right to receive the bond's par value at maturity. Equity investors receive no such promises; they hold a security that never matures, and receive no repayment of principal by the issuing firm. Moreover, the amount and timing of dividends are at the firm's sole discretion. Equally important, equity investors are the residual claimant on the firm's cash flows, with a liquidation preference subordinate to bondholders. Simply put, shareholders bear greater risk than do bondholders in the same firm. So, while credit ratings may be measures of the business and financial risks to which debt investors are exposed, they are not full measures of risks to equity investors, and we cannot draw firm inferences for one from the other.[45]

Q21. HAVE YOU REVIEWED THE RELATIONSHIP BETWEEN MR. WATSON'S TWO-STEP DCF RESULTS AND CREDIT RATINGS FOR HIS PROXY COMPANIES?

A. Yes, I have. If it is the case that one-notch differences in credit ratings are measures of differences in equity risk, those differences should be reflected in the DCF results. That is, companies with lower credit ratings should have higher DCF results; the converse also should be true. To test that relationship, I performed a regression analysis in which the

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44 https://www.standardandpoors.com/en_US/web/guest/article/-/view/sourceId/504352

45 This is a point Mr. Proctor seems to acknowledge at page 19 of his Direct Testimony: "An investor in corporate bonds takes on default risk and an investor in large company stocks takes on the full business and financial risk of the corporate enterprise."

dependent variable was the DCF result and the explanatory variable was the credit score (*i.e.*, Mr. Watson's "S&P Notches Below AAA" score[46]). The regression analysis showed no significant statistical relationship between the two. In fact, the R-squared of the regressions was only 0.03, which indicates that credit ratings accounted for, at most, 3.00 percent of the change in the DCF-estimated Cost of Equity.[47]

Q22. WHAT CONCLUSIONS DO YOU DRAW FROM THAT ANALYSIS?

A. Mr. Watson's Two-Step DCF analysis results have no meaningful relationship to credit ratings, and do not support his position that differences in credit rating notches are measures of differences in the Cost of Equity. Equally important, the Two-Step DCF analysis do not reasonably reflect the incremental return required by equity investors for a below investment grade company, such as ENO.[48]

Q23. LASTLY, DO YOU HAVE ANY OBSERVATIONS REGARDING MR. WATSON'S REVIEW OF SPECIFIC PROXY COMPANIES?

A. Yes, I do. Although I appreciate there may be reasonable differences in screening methods, there are fact-specific points I would like to address. For example, Mr. Watson suggests I should have included Unitil, Inc., because it is included in Value Line's

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[46] Exhibit No.__(BSW-4), page 5 of 9.

[47] I also considered the relationship between DCF results and credit ratings using Spearman's Rank Correlation Coefficient, which is a non-parametric measure of the correlation between two series. The Spearman Rank Correlation Coefficient between DCF results and credit ratings was approximately -0.17, which is statistically insignificant at the 95.00 percent confidence level.

[48] As discussed later in my Rebuttal Testimony, Mr. Proctor's "business risk adjustment" is flawed for several reasons, among them his disregard of the significance of the Company's below investment grade rating.

Electric Utility (East) universe, and because I have testified on behalf of Unitil companies in other rate proceedings.[49] As to Mr. Watson's first point, although Value Line does include Unitil in its Electric Utility universe, it does not provide projected Earnings Per Share growth rates for Unitil, which are used in my DCF analyses. Regarding his second point, the fact that I have testified on behalf of Unitil in other cases has no bearing on whether I consider it an appropriate proxy in this case. In each case, I develop the proxy group by reference to the subject company, not by reference to companies on whose behalf I have submitted testimony. The same applies to Mr. Watson's observation that I have testified on behalf of FortisAlberta in a hearing before the Alberta Utility Commission[50] – it has no bearing on how I would select a proxy group in this proceeding.

Mr. Watson's observations regarding Public Service Enterprise Group ("PSEG") is an example of how we consider the same data source, but arrive at different conclusions. Mr. Watson does not seem to disagree that PSEG's Power segment reported operating income of negative $359 million in 2017, but positive operating income of $13 million, and $1.43 billion in 2016 and 2015, respectively.[51] It is that variation in operating income that requires consideration in determining whether the company is a suitable proxy. In my view, it is important to consider whether a single year's negative unregulated operating income (which increases the portion of regulated operating income) reasonably represents investors' views of the segment's long-term prospects. That is an area in which my judgment differs from Mr. Watson's. I do not believe the

[49] Direct Testimony of Byron S. Watson, at 32–33.

[50] *Ibid*., at 32.

[51] Public Service Electric & Gas Company, SEC Form 10-K for the fiscal year ended December 31, 2017, at 89.

analysis necessarily lends itself to the "formulaic application" of criteria, as Mr. Watson suggests.[52]

Further, the fact that PSEG's Power segment was formed in response to regulatory restructuring in New Jersey does not change the fact that it "integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets."[53] It is a merchant (unregulated) segment and should be considered as such.[54]

Lastly, I disagree with Mr. Watson that Avangrid, Inc. ("Avangrid") should be excluded from the proxy group. Avangrid meets my all my screening criteria. It also meets all Mr. Watson's screening criteria.[55] Further, Avangrid's risk measures, as reported by Value Line, are comparable to the companies in my and Mr. Watson's proxy groups.[56]

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52 Direct Testimony of Byron S. Watson, at 35.

53 Public Service Electric & Gas Company, SEC Form 10-K for the fiscal year ended December 31, 2017, at 1.

54 Lastly, although Mr. Watson notes the company's DCF result is above the median, I do not add or remove proxy companies based on how they might affect the median results. *See* Direct Testimony of Byron S. Watson, at 35.

55 *See* Direct Testimony of Byron S. Watson, at 24–25. Although Mr. Watson discusses a low-end "economic logic" screen (*i.e*., that the two-step DCF result is at least 100 basis points greater than the investment grade corporate bond yield), Avangrid's two-step DCF result is also within FERC's "high-end" outlier screen, in which the two-step DCF result is more than 150.00 percent of the proxy group median. *See* Docket No. EL11-66-001, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at P 53; Docket No. EL14-12-0031, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P 54.

56 Source: Value Line Investment Survey as of February 28, 2019.

Avangrid is a publicly traded company[57] with two business segments: (1) Avangrid Networks, which represents the U.S. regulated electric and natural gas utility operations that serve 3.20 million customers in New York and New England; and (2) Avangrid Renewables, which owns and operates renewable electricity capacity across 22 states.[58] The regulated utility operations of Avangrid Networks account for 83.00 percent of Avangrid's 2017 operating revenues, and more than 100.00 percent of its net income.[59] Consequently, Avangrid's regulated operations represent a vast majority of total company operations. Although its ultimate parent Iberdrola, S.A. ("Iberdrola"), owns approximately 81.60 percent of the outstanding common stock, Avangrid's stock price reflects the risks associated with Avangrid's operations, not Iberdrola's. For these reasons, I believe it is reasonable to include Avangrid in the proxy group.

D. Capital Asset Pricing Model

Q24. PLEASE SUMMARIZE MR. PROCTOR'S CAPM ANALYSES.

A. Mr. Proctor provides two CAPM analyses, which vary based on his assumed risk-free rate. In each case, he begins with the long-term arithmetic average return on large capitalization stocks, as reported by Duff & Phelps. Mr. Proctor's calculations, which produce CAPM estimates of 6.68 percent and 7.57 percent, are presented in Table 2, below.

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[57] Avangrid is the merged company of Iberdrola USA (formerly Energy East Corporation) and UIL Holdings Corporation. Energy East Corporation and UIL were publicly traded companies on the New York Stock Exchange. *See* Avangrid, Inc. SEC Form 10-K for the Year Ended December 31, 2017, at 6, 8.

[58] Avangrid, Inc. SEC Form 10-K for the Year Ended December 31, 2017, at 6.

[59] Avangrid, Inc. SEC Form 10-K for the Year Ended December 31, 2017, at 62.

Table 2: Mr. Proctor's CAPM Estimates[60]

	Arithmetic Mean	
Large-Cap Stocks	12.10%	12.10%
Long-term Gov't Bonds	6.00%	-
U.S. Treasury Bills	-	3.40%
Market Risk Premium	6.10%	8.70%
Beta Coefficient	0.59	0.59
Equity Risk Premium	3.62%	5.16%
Risk-Free Rate	3.06%	2.41%
Return on Equity	6.68%	7.57%

As Table 2 indicates, Mr. Proctor's analyses reflect two estimates of the risk-free rate: 3.06 percent (the current 30-year Treasury Bond yield), and 2.41 percent (the current 13-week Treasury Bill yield).

Q25. ARE THE 6.68 PERCENT AND 7.57 PERCENT ESTIMATES MR. PROCTOR'S EVENTUAL CAPM RECOMMENDATION?

A. No, they are not. As discussed below, Mr. Proctor focuses on the 7.57 percent result, which is based on the short-term Treasury Bill rate. To that, he adds 84 basis points to reflect incremental business risks (81 basis points), and the effect of common stock flotation costs (three basis points).

60 Exhibit No.__(JMP-5), Exhibit No.__(JMP-6). *See also*, Duff & Phelps, 2018 SBBI Yearbook, at 6-17.

Reasonableness of Mr. Proctor's CAPM Result

Q26. BEFORE DISCUSSING YOUR METHODOLOGICAL CONCERNS WITH MR. PROCTOR'S APPROACH, DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING HIS CAPM ESTIMATES?

A. Yes, I do. In Table No. 1 (page 19) of his Testimony, Mr. Proctor provides "Summary Statistics of Annual Total Returns" from 1960 through 2017 for several asset classes, including large (capitalization) stocks, long-term Government bonds, intermediate-term Government bonds, and U.S. Treasury bills. He presents the arithmetic mean and standard deviation of annual returns for each, referring to the standard deviation as the "best measure of risk".[61]

Plotting Mr. Proctor's data in risk/return space, we see a very strong relationship between the two. In fact, the standard deviation explains about 97.50 percent of the change in the annual (arithmetic) average return (the R^2 is about 0.975; *see*, Chart 5, below).[62] We can use that relationship to assess the reasonableness of Mr. Proctor's CAPM estimates in the following manner. First, based on Mr. Proctor's proposition that historical risks and returns are the best measure of expected risks and returns,[63] we can assume the regression line in Chart 5 expresses the market's expectations of both. Under that construct, any return falling below the line does not sufficiently compensate investors for expected risk (it is considered "inefficient"). At issue, therefore, is where Mr. Proctor's CAPM results fall in the risk/return space his data provides.

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61 Direct Testimony of James M. Proctor, at 18.

62 That is, the standard deviation explains about 97.50 percent of the change in the annual (arithmetic) average return.

63 *See* Direct Testimony of James M. Proctor, at 17–18.

To make that determination, I began with Mr. Proctor's observation that the Company's S&P credit rating (BBB+) "falls within the range of [the] proxy group."[64] Based on data provided by S&P Global Market Intelligence, I found the average S&P issuer credit rating within the utility sector (including electric and gas utilities) currently is BBB+.[65] It therefore follows that Mr. Proctor's CAPM estimates would apply to the broad utility sector. To pair Mr. Proctor's CAPM estimates with the standard deviation of returns, I calculated the standard deviation of annual total return on the Dow Jones Utility average from 1928 through 2018, which I found to be about 20.60 percent (*see*, Chart 5, below).[66]

Combining that standard deviation with Mr. Proctor's CAPM results makes clear his estimates are too low to be reasonable. A rational investor would not accept a return so far below those expected of comparable-risk assets. Taking the analysis a step further, if the market is efficient, the return on utility investments would have to increase well above Mr. Proctor's recommended levels to make them reasonable alternatives. The higher return would require a lower market price, a disadvantageous result for utilities requiring continuing and efficient access to capital markets.

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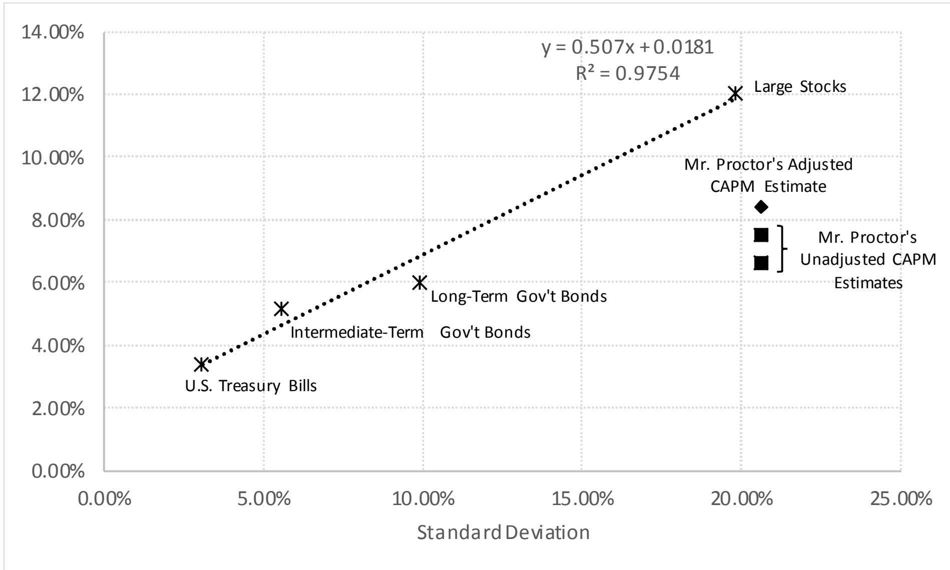
64 *Ibid*., at 27.

65 Source: S&P Global Market Intelligence.

66 Notably, the standard deviation of returns – which Mr. Proctor asserts is "the best measure of risk" – for the Dow Jones Utility Index (20.60 percent) is above the long-term average standard deviation for large capitalization stocks (19.80 percent). By Mr. Proctor's logic, utility stocks are arguably "riskier" than large stocks. Source: Bloomberg Professional, Duff & Phelps 2018 SBBI Yearbook, at 6-17 (*see also,* Mr. Proctor's Table No. 1).

Chart 5: Mr. Proctor's CAPM Estimate in Risk/Return Space[67]



As Chart 5 demonstrates, Mr. Proctor's CAPM estimates, even adjusted for "business risk", fall far below the line indicating the historical risk/return relationship. His estimates therefore provide too little return in exchange for taking on too much risk; it is "dominated" by more efficient alternatives.

Risk-Free Rate of Return

Q27. WHY DO YOU DISAGREE WITH MR. PROCTOR'S USE OF THE 13-WEEK TREASURY BILL YIELD AS A MEASURE OF THE RISK-FREE RATE?

A. As explained in my Revised Direct Testimony, the security used as the risk-free rate should match the life of the underlying investment, and referred to utility stocks as "long-

67 Source: Direct Testimony of James M. Proctor at 19, Table No. 1; Bloomberg Professional.

duration investments".[68] Mr. Proctor disagrees with that approach, and did not consider his CAPM results based on the 30-year Treasury yield.

Q28. ON WHAT BASIS DOES MR. PROCTOR PREFER THE 13-WEEK TREASURY BILL OVER THE 30-YEAR TREASURY BOND?

A. Mr. Proctor argues the longer-term (30-year) security should not be used because:

> Treasury bills are about as safe and risk-free an investment as one can find. There is virtually no perceived risk of nominal default and due to their short-term they exhibit less price volatility. The only real risk for treasury bills relates to inflation risk. Longer term government bond prices fluctuate more than T-Bills as interest rates vary. The longer the term for government bonds the greater the risk and variability in its total returns due to the interest rate risks. Longer term government bonds are also subject to inflationary risks.[69]

Mr. Proctor therefore seems to prefer the shorter-term security, largely because it is less susceptible to inflation risk.

As to utility equity representing a long-duration investment, Mr. Proctor believes my position simply is "wrong".[70] He argues that "[u]nlike for a bond, investments in an electric utility's common equity do not have stated maturity dates", and that "[a]n investor in an electric utility may hold its investment for 5 minutes, 30 years, or any time frame in between."[71]

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[68] Revised Direct Testimony of Robert B. Hevert, at 32.

[69] Direct Testimony of James M. Proctor, at 19.

[70] *Ibid*., at 52.

[71] *Ibid*., at 52.

Q29. DO YOU AGREE WITH MR. PROCTOR ON THAT POINT?

A. No, I do not. The proper tenor of the risk-free rate depends on the *duration* of the underlying security, not a given investor's holding period.[72] That position is well-established and widely applied. As noted by Morningstar, the source on which Mr. Proctor relies for the Market Risk Premium component of the CAPM:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. *If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years*.[73]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "[i]n theory, when determining the risk-free rate and the matching [Equity Risk Premium] you should be matching the risk-free security and the [Equity Risk Premium] with the period in which the investment cash flows are expected."[74] The Chartered Financial Analyst program likewise notes the risk-free rate used in the CAPM should match the timing of the expected asset's cash flows:

> A risk-free asset is defined here as an asset that has no default risk. A common proxy for the risk-free rate is the yield on a default-free government debt instrument. In general, the selection of the appropriate risk-free rate should be guided by the duration of projected cash flows. If we are evaluating a project with an estimated useful life

[72] Revised Direct Testimony of Robert B. Hevert, at 32.

[73] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44. [emphasis added]

[74] Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. [clarification added]

> of 10 years, we may want to use the rate on the 10-year Treasury bond.[75]

As these sources agree, it is the duration of cash flows, not the investor's holding period, that determines the proper risk-free rate.

Q30. PLEASE EXPLAIN THE TERM "DURATION" AND HOW IT IS USED IN PRACTICE.

A. In finance, "duration" (whether for bonds or equity) typically refers to the present value weighted time to receive a given security's cash flows. In terms of its practical application, duration is a measure of the percentage change in the market price of a given stock in response to a change in the implied long-term return of that stock. A common investment strategy is to "immunize" the portfolio by matching the duration of investments with the term of the underlying asset in which the funds are invested, or the term of a liability being funded.

Using Mr. Watson's Two-Step DCF method, I was able to calculate the equity duration of the companies in his proxy group. As demonstrated in ENO Exhibit RBH - 22, the mean and median equity duration for Mr. Watson's proxy group is about 30 years. Although the current duration of 30-year Treasury bonds is 20 years,[76] it provides the longest available duration and, therefore, is the proper security for his CAPM analyses. I therefore continue to believe it is appropriate to use the long-term (*i.e.*, 30-year) Treasury yield as the measure of the risk-free rate.

[75] 2011 CFA Curriculum Level I, Volume 4 at 52.

[76] *See* ENO Exhibit RBH-23.

Q31. DO MR. PROCTOR'S OBSERVATIONS REGARDING INTEREST RATE AND INFLATION RISK CHANGE YOUR POSITION?

A. No, they do not. If Mr. Proctor is concerned with those risks, he should use the shortest-term Treasury security, the four-week Treasury bill, as the risk-free security.[77] Because he does not, Mr. Proctor may consider the issue as a matter of degree, recommending the 13-week Treasury yield simply because it is a shorter-term security than the 30-year bond. As discussed above, however, the relevant perspective is duration matching, not the maturity of a given Treasury security in isolation.

Q32. PUTTING ASIDE THE ISSUE OF EQUITY DURATION, DOES MR. WATSON'S DCF MODEL RECOGNIZE THE PERPETUAL NATURE OF EQUITY?

A. Yes, it does. As Mr. Watson correctly observes, his DCF model assumes an infinite horizon.[78] If it did not, the model would produce implausibly low results. As shown in ENO Exhibit RBH-24, for example, an assumed holding period of five years produces mean and median ROE estimates of about negative 38.00 percent; a ten-year holding period produces an expected ROE of about negative 12.70 percent. The only way Mr. Watson's DCF results can be realized is if the shares were sold at the end of those holding periods, and the prices at which they are sold reflect cash flows in perpetuity (*see*, ENO Exhibit RBH-25). The risk-free rate therefore should reflect the perpetual

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77 *See*, https://www.federalreserve.gov/releases/h15/

78 Direct Testimony Byron S. Watson, at 14–15.

nature of equity. Again, because the longest-dated Treasury security is 30 years, that is the appropriate term for this purpose.

Market Risk Premium

Q33. PLEASE BRIEFLY SUMMARIZE HOW MR. PROCTOR ESTIMATED THE EXPECTED MARKET RISK PREMIUM.

A. Mr. Proctor's two Market Risk Premium estimates begin with the long-term arithmetic average return on large capitalization stocks, as provided by Duff & Phelps, from which he subtracts the total return on long-term Government securities, and the 13-week Treasury Bill yield.[79]

Q34. DO YOU AGREE WITH MR. PROCTOR'S USE OF HISTORICAL ESTIMATES OF THE MARKET RISK PREMIUM?

A. No, I do not. The Market Risk Premium represents the additional return required by equity investors to assume the risks of owning the "market portfolio" of equity relative to long-term Treasury securities. As with other elements of Cost of Equity analyses, the Market Risk Premium is meant to be a forward-looking parameter. Relying on a Market Risk Premium calculated using historical returns may produce results that are inconsistent with investor sentiment and current conditions in capital markets. The fundamental analytical issue in applying the CAPM is to ensure that all three components

[79] Direct Testimony of James M. Proctor, at 18; Exhibit No.__(JMP-5), Exhibit No.__(JMP-6).

of the model (*i.e.*, the risk-free rate, Beta, and the Market Risk Premium) are consistent with market conditions and investor expectations. As, Morningstar observes:

> It is important to note that the expected equity risk premium, as it is used in discount rates and cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[80]

I also disagree with Mr. Proctor's view that the Market Risk Premium is static over time and across capital market environments.[81] Longstanding financial research has shown the Market Risk Premium to vary over time and with market conditions. French, Schwert, and Stambaugh, for example, found the Market Risk Premium to be positively related to predictable market volatility.[82] Using forward-looking measures of the expected market return, Harris and Marston found "…strong evidence…that market risk premia change over time and, as a result, use of a constant historical average risk premium is not likely to mirror changes in investor return requirements."[83] Among their findings is that the Market Risk Premium is inversely related to Government bond yields. That is, as interest rates fall, the Market Risk Premium increases. Unlike Mr. Proctor's position, financial researchers have found the Market Risk Premium to be time-varying, and a function of economic parameters including interest rates.[84]

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80 Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 53.

81 At page 54 of his Direct Testimony, Mr. Proctor states "More importantly, I have not seen where mathematicians have found mathematically reliable evidence that the expected MRP has changed over time."

82 Kenneth R. French, G. William Schwert, Robert F. Stambaugh, *Expected Stock Returns and Volatility*, Journal of Financial Economics 19 (1987), at 27.

83 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 69.

84 As explained in my Revised Direct Testimony at 36–37, there is a similar negative relationship between interest rates and the Equity Risk Premium.

Q35. WHAT DO YOU CONCLUDE FROM THOSE ANALYSES?

A. The principal conclusion is that the Market Risk Premium is not static, but changes over time and inversely to the level of Treasury yields. That finding is important, if only because the current Treasury yield remains below the 6.00 percent yield that underlies Mr. Proctor's Market Risk Premium calculation (based on 30-year yields).

Q36. DO YOU AGREE WITH MR. PROCTOR'S USE OF THE TOTAL RETURN ON LONG-TERM GOVERNMENT BONDS IN CALCULATING THE MARKET RISK PREMIUM?

A. No, I do not. As Duff & Phelps points out, the total return on a security is composed of three components: (1) the income return; (2) capital gains (or capital losses, if the value of the security falls); and (3) reinvestment return.[85] The income return is generally defined as the coupon, or interest rate on the security, which does not change over the life of the security. In contrast, the value of the security rises or falls as interest rates change, resulting in uncertain capital gains. Because the income return is the only "riskless" component of the total return, it is the measure that should be used in calculating the Market Risk Premium.

[85] Duff & Phelps, 2018 SBBI Yearbook, at 2-7.

Q37. LASTLY, MR. PROCTOR BELIEVES YOUR FORWARD-LOOKING MARKET RISK PREMIUM ESTIMATE IS TOO HIGH, LARGELY BECAUSE IT IS GREATER THAN HISTORICAL EXPERIENCE.[86] WHAT IS YOUR RESPONSE TO MR. PROCTOR ON THAT POINT?

A. I disagree. First, as explained above, contrary to Mr. Proctor's view, longstanding published research has shown the Market Risk Premium to be time-varying, and a function of variables such as expected volatility, and interest rates. Mr. Proctor's position that an expected Market Return, or Market Risk Premium, should only be assessed by reference to historical data is misplaced.[87] That aside, as discussed in my response to Mr. Walters, my market risk premium estimates are consistent with historical observations and have occurred roughly half the time (*see* Chart 21, below) between 1926 and 2017.[88]

Second, the method I applied to estimate the expected market return is consistent with academic research, for example, by Harris and Marston.[89] It is a reasonable method, used by finance researchers to understand the factors affecting the Market Risk Premium.

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[86] Direct Testimony of James M. Proctor, at 55–56.

[87] If the long-term arithmetic average is the best measure of an expected return, it would be important to review the long-term average authorized ROE for electric utilities which, based on ENO Exhibit RBH-7 (to my Revised Direct Testimony) is 12.63 percent.

[88] *See* ENO Exhibit RBH-31.

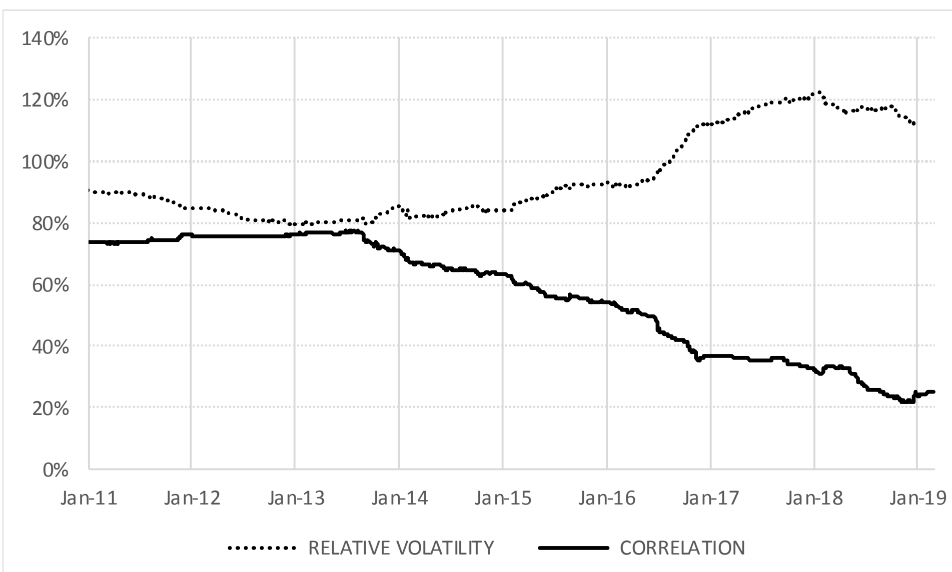
[89] Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts Forecasts*, Darden Graduate School of Business, University of Virginia, Working Paper No. 99-08, (1999).

Constancy of Beta Coefficients

Q38. AT PAGE 33 OF HIS TESTIMONY MR. PROCTOR REFERS TO CHANGES IN BETA COEFFICIENTS, ARGUING THAT THOSE CHANGES PROVIDE "ADDITIONAL EVIDENCE BUSINESS RISK IS DECREASING." WHAT IS YOUR RESPONSE TO MR. PROCTOR ON THAT POINT?

A. I agree with Mr. Proctor's observation, but disagree with the conclusion he draws from it. As discussed in my Revised Direct Testimony, Beta coefficients reflect two components: (1) the volatility of the subject company's returns relative to the overall market's return volatility, and (2) the correlation in returns between the subject company and the overall market.[90] Looking at those individual parameters, since 2013 the correlation between Mr. Proctor's proxy group and the S&P 500 has declined, but the relative volatility has increased (*see,* Chart 6, below).

Chart 6: Components of Beta Coefficients Over Time[91]



[90] Revised Direct Testimony of Robert B. Hevert, at 31.

[91] Source: S&P Global Market Intelligence. Calculated as an index.

Q39. WHAT CONCLUSIONS DO YOU DRAW FROM THAT DATA?

A. In reviewing historical market data, Mr. Proctor observes that "[e]conomic and financial literature and experts consider the standard deviation of returns on investment to be the best measure of risk."[92] By that standard, risk for utility investors has been increasing relative to the overall market (that is, relative volatility has increased). As Chart 6 demonstrates, the downward movement in Beta coefficients is related to the decrease in correlation coefficients, not a decrease in the relative volatility of utility returns.

At issue, then is why correlations have fallen, and whether we should view that change as a measure of investors' long-term expectations. As noted earlier, beginning in 2012 the Federal Reserve began its third round of Quantitative Easing, which was meant to put downward pressure on long-term interest rates. The effect of that policy may have been to encourage investors, at times, to "reach for yield" by investing in dividend-paying sectors, such as utilities. When macroeconomic conditions evolved such that interest rates began to increase or other growth-based sectors appeared more appealing, investors rotated out of the utility sectors.

Similarly, because (as discussed in my Revised Direct Testimony)[93] utilities faced downward credit pressure due to the TCJA, and because they could not benefit from the TCJA in ways other sectors could, utilities became relatively less attractive. In short, since 2012 federal policies affected trading decisions in ways that have caused the utility sector's correlation with the overall market to fall, causing the decline in Beta

92 Direct Testimony of James M. Proctor, at 18.

93 Revised Direct Testimony of Robert B. Hevert, at 61.

coefficients Mr. Proctor observes. As discussed in my Revised Direct Testimony, those policies now are being "normalized".[94]

The question is whether the currently low Beta coefficients adequately reflect expected systematic risk and, therefore, required returns. As discussed below, published research has found low-Beta coefficient companies (such as utilities) have tended to earn returns greater than those predicted by the CAPM. Consequently, the relatively low Beta coefficients Mr. Proctor observes likely under-estimate investors' return requirements. One means of addressing Mr. Proctor's observation is the Empirical Capital Asset Pricing Model, discussed below.

Empirical Capital Asset Pricing Model

Q40. PLEASE BRIEFLY DESCRIBE THE EMPIRICAL CAPITAL ASSET PRICING MODEL ("ECAPM", OR "EMPIRICAL CAPM").

A. The Empirical CAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than the market mean of 1.00, and over-estimate returns for relatively high-Beta coefficient stocks.[95] Fama and French succinctly describe the empirical issue addressed by the ECAPM when they note "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[96] Similarly, Dr. Roger Morin observes that "[w]ith few exceptions, the

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[94] *Ibid*., at 72.

[95] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175–176.

[96] Eugene F. Fama and Kenneth R. French, The Capital Asset Pricing Model: Theory and Evidence, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted."[97] As Dr. Morin also explains, the ECAPM "makes use" of those findings, and estimates the Cost of Equity based on the following equation:[98]

$$k_e = R_f + \alpha + \beta(MRP - \alpha) \quad [1]$$

where α, or "alpha," is an adjustment to the risk/return line, and "MRP" is the Market Risk Premium (defined above). Summarizing empirical evidence regarding the range of estimates for alpha, Dr. Morin explains that the model "reduces to the following more pragmatic form"[99]:

$$k_e = R_f + 0.25(R_m - R_f) + 0.75\beta(R_m - R_f) \quad [2]$$

where:

k_e = the investor-required ROE;

R_f = the risk-free rate of return;

β = Adjusted Beta coefficient of an individual security; and

R_m = the required return on the market.

The relationship between expected returns from the CAPM and ECAPM can be seen in Chart 7, below. That chart, which reflects Mr. Proctor's risk-free rate and Market Risk Premium, illustrates the extent to which the CAPM understates the expected return relative to the ECAPM when Beta coefficients are less than 1.00.

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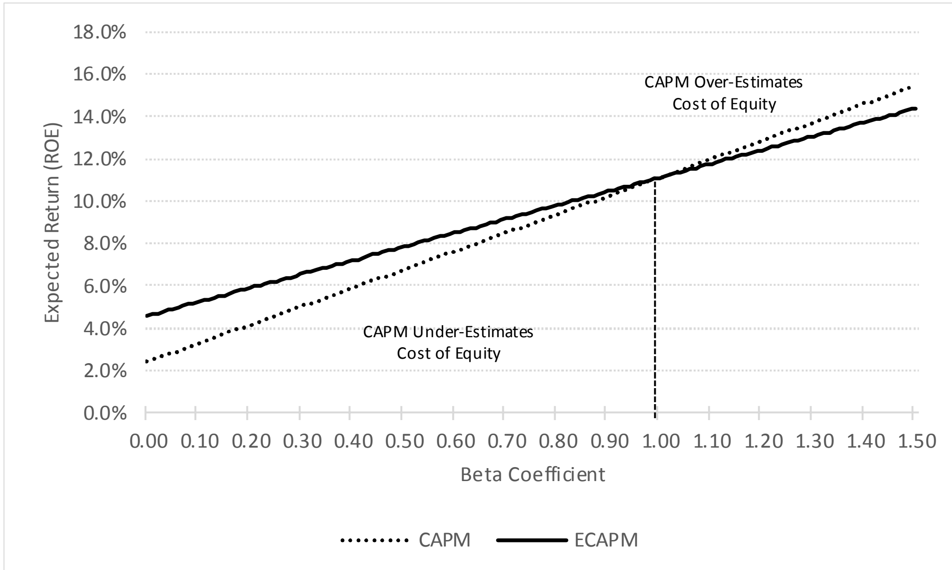
[97] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 175.

[98] *Ibid*., at 189.

[99] *Ibid*., at 190. Equations [1] and [2] tend to produce similar results when "alpha" is in the range of 1.00 percent to 2.00 percent. *See* ENO Exhibit RBH-26. As Dr. Morin explains, alpha coefficients in that range are highly consistent with those identified in prior published research.

Chart 7: CAPM and ECAPM Expected Returns[100]



The ECAPM is an adjustment to the risk/return line which, as noted in Chart 7 above, is flatter than the CAPM assumes. That adjustment is required even with the use of adjusted Beta coefficients, such as those provide by Value Line. As Dr. Morin observes:

> Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. *The ECAPM and the use of adjusted betas comprised two separate features of asset pricing…Both adjustments are necessary.*[101]

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[100] *See* ENO Exhibit RBH-26. The finding that the ECAPM is not an adjustment to the Beta coefficient is clear in Equation [1] ($k_e = R_f + \alpha + \beta(MRP - \alpha)$), in which the alpha coefficient increases the intercept (the expected return when the Beta coefficient equals zero), and reduces the Market Risk Premium.

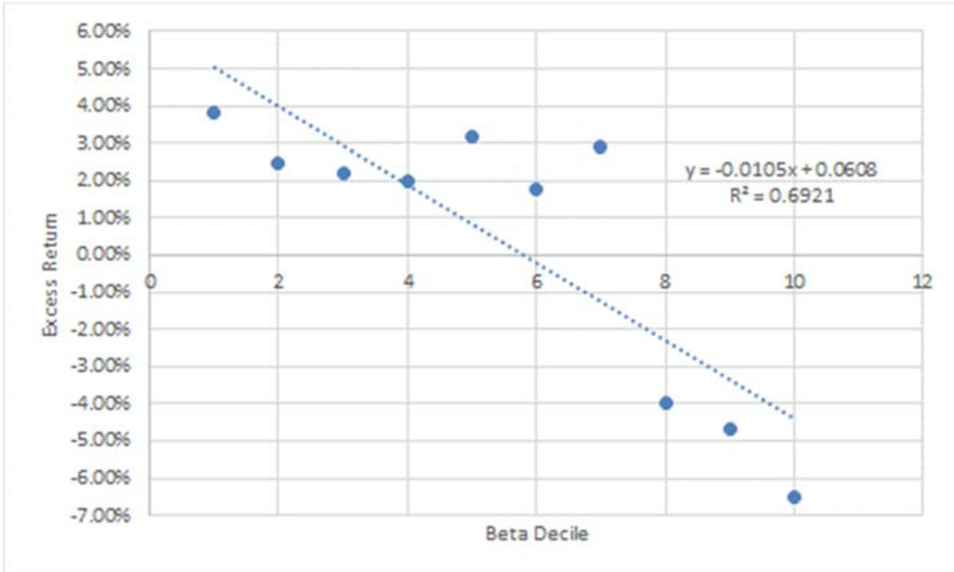
[101] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 191 [*emphasis added*].

Q41. HAVE YOU UNDERTAKEN ANY INDEPENDENT ANALYSES TO DETERMINE WHETHER THERE IS A RELATIONSHIP BETWEEN BETA COEFFICIENTS AND EXCESS RETURNS PRODUCED BY THE CAPM AND ECAPM?

A. Yes, I performed an analysis of excess returns[102] produced by the CAPM, by Beta coefficient decile, over the ten years ended 2018. The analysis compared the observed returns of the companies in the S&P 500 Index to expected returns based on the CAPM. Observed returns were calculated as the total return for each company from the first day of a given year to the end of that year. The expected return for each company was calculated using the CAPM as applied to the following annual data: (1) a risk-free rate equal to the average 30-year Treasury yield for that year; (2) an adjusted Beta coefficient as of the beginning of the year using Bloomberg's standard calculation methodology (two years of weekly return data, using the S&P 500 Index as the comparison benchmark); and (3) a market return equal to the S&P 500 Index total return for that year. The companies were grouped into deciles each year based on their Beta coefficients, and the median excess return (or return deficiency) was calculated for each decile group. Excess returns were calculated as the observed return less the return implied by the CAPM. Chart 8 (below) summarizes those results.

102 As noted below, "excess returns" is defined as the observed return less the return implied by the CAPM.

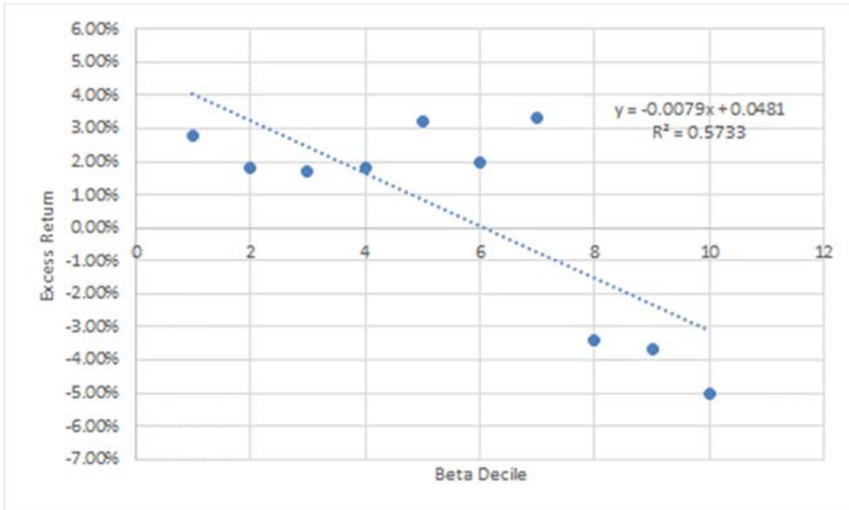
Chart 8: Excess Returns Under CAPM[103]



As Chart 8 demonstrates, the relationship between Excess Return and Beta coefficient deciles is strong, with deciles explaining more than 69.00 percent of the Excess Return. Using the same data and calculating the Excess Return by reference to the ECAPM (as defined by Equation [2], above), produces the same downward sloping relationship, but not to the same degree (*see* Chart 9, below).

103 Source: Bloomberg Professional Services.

Chart 9: Excess Returns Under the ECAPM[104]



There are two principal observations to be drawn from the data presented in Charts 8 and 9. First, under the ECAPM the slope coefficient falls somewhat (relative to the CAPM), suggesting a flatter relationship between Beta coefficient deciles and the excess return. The flatter slope moves closer to the point at which the excess return is zero across all deciles. Second, the excess return values are somewhat moderated under the ECAPM; the high excess returns are lower than under the CAPM, and the low excess returns are higher. Again, that finding suggests the ECAPM mitigates, but does not solve the issue of the CAPM underestimating returns for low Beta coefficient firms.

In summary, Charts 8 and 9 support the position that the CAPM tends to underestimate returns for low-Beta coefficient firms, and the ECAPM moderates but does not eliminate that effect. Because the ECAPM addresses the drift in Beta coefficients

104 Source: Bloomberg Professional Services.

Mr. Proctor observes, I believe it is a reasonable method, and have included results based on the ECAPM in my updated analyses.[105]

E. Discounted Cash Flow Analyses

Q42. PLEASE BRIEFLY DESCRIBE MR. WATSON'S CONSTANT GROWTH DCF ANALYSIS AND RESULTS.

A. Mr. Watson calculates an average dividend yield of 3.38 percent by dividing each proxy company's annualized dividend by its monthly average stock price for the six-month period ending December 2018.[106] For the expected growth rate, Mr. Watson relies on Earnings Per Share growth rate projections from Thomson Reuters.[107] Based on those estimates, Mr. Watson calculates a Constant Growth DCF-based range of 5.13 percent to 12.11 percent, with mean and median results of 8.60 percent and 8.16 percent, respectively.[108]

Q43. WHAT CONCERNS DOES MR. WATSON RAISE REGARDING THE CONSTANT GROWTH DCF METHOD?

A. Mr. Watson summarizes his concern by observing "trees don't grow to the sky".[109] He argues that any company whose expected growth rate exceeds expected GDP growth

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105 *See* ENO Exhibit RBH-18.

106 Exhibit No.__(BSW-4), at 2. 3.38 percent represents the average dividend yield of Mr. Watson's final proxy group.

107 Exhibit No.__(BSW-4), at 2.

108 Exhibit No.__(BSW-4), at 1.

109 Direct Testimony of Byron S. Watson, at 14.

eventually will swallow the entire economy. In the context of the Constant Growth DCF model, however, the relevant question is whether the assumed growth rate is fundamentally and empirically related to stock valuation levels. As discussed in my Revised Direct Testimony, that is the case for expected earnings growth rates.[110] Nonetheless, Mr. Watson addresses his concern by applying the Two-Step DCF method.

Q44. PLEASE SUMMARIZE MR. WATSON'S TWO-STEP DISCOUNTED CASH FLOW MODEL.

A. Mr. Watson's Two-Step method is based on the approach used by the FERC, which applies weights of two-thirds and one-third, respectively, to analysts' earnings growth rate projections, and projected growth in nominal Gross Domestic Product ("GDP"). As with FERC's approach, Mr. Watson's long-term growth rate of 4.42 percent is taken from three sources: (1) the Energy Information Administration ("EIA"), (2) the Social Security Administration ("SSA"), and (3) IHS Global Insights.[111] Based on those inputs, Mr. Watson produces ROE estimates ranging from 5.74 percent to 10.64 percent, with mean and median estimates of 8.33 percent and 8.09 percent, respectively. Mr. Watson relies on the 8.09 percent median result as his (unadjusted) ROE recommendation.[112]

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110 Revised Direct Testimony of Robert B. Hevert, at 19–21.

111 Direct Testimony of Byron S. Watson, at 18–19.

112 Exhibit No.__(BSW-4), at 1.

Q45. AT PAGES 20 AND 21 OF HIS DIRECT TESTIMONY, MR. WATSON IS CRITICAL OF THE LONG-TERM GDP GROWTH RATE ASSUMED IN YOUR MULTI-STAGE DCF ANALYSIS. WHAT IS YOUR RESPONSE TO MR. WATSON ON THAT POINT?

A. First, as demonstrated in Charts 19 and 20 in my response to Mr. Walters, my long-term growth rate is consistent with historical observed nominal GDP. Further, as to the SSA GDP growth rate forecast Mr. Watson cites (and as explained further in my response to Mr. Walters), my growth rate estimate falls within the range of the "cases" SSA considers.[113]

Mr. Watson also points to the Congressional Budget Office ("CBO"), which provides a real GDP annual growth rate estimate of 1.90 percent over the 2019 – 2028 forecast horizon. He suggests the Council take those projections into account.[114] The CBO, however, provides updates regarding its forecasting record. In that context, the CBO noted that comparisons to other forecasts are not always apt, at least in part because they may be based on different assumptions and used for different purposes.[115] The CBO also observes that it is required to assume that future fiscal policy generally will reflect current law, so that it may provide a benchmark against which proposed changes in law

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113 Tables V.B1 and V.B2 of the <u>2018 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds</u> includes "Low Cost" scenario assumptions of 2.90 percent and 3.20 percent for the GDP Price Index and CPI, respectively, and 2.70 percent for Real GDP Growth, over the period 2027 through 2092. Combined, those projections indicate nominal GDP growth of approximately 5.60 percent to 5.90 percent.

114 Direct Testimony of Byron S. Watson, at 20–21.

115 *CBO's Economic Forecasting Record: 2017 Update*, October 2017, at 4–5.

may be assessed.[116] The CBO goes on to explain that "because forecasters make different assumptions about future fiscal policy, it is difficult to compare the quality of forecasts without considering the role of expected changes in laws."[117] Given that purpose and structure, I disagree that the CBO's forecasts should be used to validate Mr. Watson's result.

The CBO also notes that among its two-year forecasts (since the early 1980s), the forecast error for "real output growth" and inflation (measured by the Consumer Price Index) has been 1.30 percentage points and 0.90 percentage points, respectively.[118] That range of error, if applied to the 1.90 percent long-term CBO forecast noted by Mr. Watson, suggests that the 5.45 percent Mr. Watson finds concerning is within a reasonable range.[119]

Second, although Mr. Watson argues that because it has been used by FERC his approach is reasonable, in its recent *Order Directing Briefs*, FERC concluded that "relying on the DCF methodology alone will not produce a just and reasonable ROE"[120]

116 *Ibid*., at 8. "In particular, forecasters in the private sector attempt to predict the future stance of federal fiscal policy, and the Administration's forecasts assume the adoption of the fiscal policy reflected in the President's proposed budget. CBO, however, is required to assume that fiscal policy in the future will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed changes in law. Forecasting errors may be driven by those different assumptions, particularly when policymakers are considering major changes in the fiscal policy embedded in current law."

117 *CBO's Economic Forecasting Record: 2017 Update*, October 2017, at 4–5.

118 *Ibid*., at 9. Root mean square error.

119 CBO's 1.90 percent long-term projection of real GDP corresponds to a long-term projection of nominal GDP of 4.00 percent. 4.00% + 1.30% + 0.90% = 6.20%, which is above my 5.45 percent long-term growth rate.

120 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

and instead proposes to include the Bond Yield Plus Risk Premium, Expected Earnings, and CAPM approaches, to estimate the Cost of Equity.

Q46. IS YOUR MULTI-STAGE DCF MODEL DEPENDENT ON A LONG-TERM GROWTH RATE ASSUMPTION, AS MR. WATSON SUGGESTS?[121]

A. No, it is not. As I explained in my Revised Direct Testimony, an alternative to using a terminal growth rate is to develop the terminal price based on Price/Earnings ratios. Those results are presented in Table 6 (page 30) of my Revised Direct Testimony.

Q47. AS A PRACTICAL MATTER, DO THE FORECAST HORIZONS IN THE EIA AND GLOBAL INSIGHTS PROJECTIONS CORRESPOND TO MR. WATSON'S TWO-STEP DCF METHOD?

A. No, they do not. As noted earlier, the "two-step" DCF method is applied in a manner similar to the Constant Growth DCF model; the only difference is that the growth rate is a weighted average of analysts' earnings growth projections, and nominal GDP growth rate projections. We can convert Mr. Watson's approach to a true two-step DCF analysis, in which the first stage growth rate applies for a finite period, and the long-term growth rate applies from that point on (in perpetuity). In that case, the DCF estimate is the Internal Rate of Return ("IRR") that sets the market price equal to the present value of the projected dividends. To determine the year in which the second stage growth applies, we only need set the IRR equal to Mr. Watson's "two-step" DCF result.

121 Direct Testimony of Byron S. Watson, at 16.

To do so, I first replicated Mr. Watson's Constant Growth DCF results, based on the fundamental Present Value formula:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}. .$$

As noted earlier the discount rate, *k*, is the Cost of Equity found in the simplified formula

$$k = \frac{D(1+g)}{P_0} + g .$$

I then altered the Present Value formula such that the growth in dividends would change from the first-stage growth to the second stage in a given year (which I refer to as the "transition year"). At that point, all that was needed was to find the transition year that caused the IRR to equal Mr. Watson's two-step DCF estimate (by company).

As shown in ENO Exhibit RBH-22, Mr. Watson's "two-step" DCF approach implicitly assumes the first stage growth rate transitions to his assumed 4.42 percent growth rate in the 35th year. Mr. Watson has not explained why that is a reasonable assumption, or how it corresponds to the forecast horizons from the sources he cites. In my view, assuming – implicitly or explicitly – growth rates will transition in the 35th year, without a basis for that assumption is nearly arbitrary. Because it is the principal method on which Mr. Watson relies, I do not believe his "two-step" DCF approach should be given weight in determining the Company's ROE.

F. Bond Yield Plus Risk Premium Approach

Q48. PLEASE SUMMARIZE MR. PROCTOR'S RESPONSE TO YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. Mr. Proctor believes the approach should be "discouraged" because it:

> … is neither based on sound economic theory, a mathematical model, nor observed investor behavior in the markets of debt and equity securities. Instead, it is based on the observed behavior of regulatory commissioners setting an authorized ROE. That is, regulatory agencies setting a commission-authorized ROE which may be based on any number of economic or non-economic factors.[122]

In short, Mr. Proctor feels the approach is "naïve and over-simplified", susceptible to bias from settlements, and "does not address the relationship between the opportunity cost of equity and interest rates from a free market-based perspective."[123]

Q49. WHAT IS YOUR RESPONSE TO MR. PROCTOR'S POSITION THAT THE RISK PREMIUM ANALYSIS RELIES ON UTILITY COMMISSIONS' BEHAVIOR RATHER THAN INVESTOR BEHAVIOR?

A. Although they are based on regulatory proceedings, those cases, and their associated decisions, reflect the same type of market-based analyses at issue in this proceeding. In my experience in over 250 cases, capital market conditions and the concerns of investors are not foreign concepts to regulatory commissions. And although regulatory commissions must balance the interests of investors and ratepayers, investors are aware of that obligation.

Because authorized returns are publicly available (the proxy companies disclose authorized returns, by jurisdiction, in their 2017 SEC Form 10-Ks),[124] it is reasonable to

122 Direct Testimony of James M. Proctor, at 58.

123 *Ibid*., at 58–59.

124 *See*, *for example*, American Electric Power Company, Inc., SEC Form 10-K for the year ended December 31, 2017, at 4; Entergy Corporation., SEC Form 10-K for the year ended December 31, 2017, at 31; WEC Energy Group, Inc., SEC Form 10-K for the year ended December 31, 2017, at 139-143; Xcel Energy, Inc., SEC Form 10-K for the year ended December 31, 2017, at 131-136.

conclude that data is reflected, at least to some degree, in investors' return expectations and requirements. In my view, Mr. Proctor's 7.57 percent CAPM result, which he argues is based on a more defensible method, is so far removed from the returns investors know to be available elsewhere that investors would not see it as meeting the *Hope* and *Bluefield* standards.

As to Mr. Proctor's view that the approach is not "based on sound economic theory"[125], again I disagree. At footnote 34 to my Revised Direct Testimony, I referred to Brigham, Shome, and Vinson's article, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*. In that article, the authors point out that "with 'proper' regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds."[126] In that case, if concerns regarding future inflation increase, the perceived risk of bonds would increase more than the perceived risk of equity. That is, the return required on equity would increase less than the return required on bonds, thereby decreasing the Equity Risk Premium.

In the same footnote I referred to Harris and Marston who (as noted earlier) found the Equity Risk Premium to change inversely to changes in interest rates. I also referred to Maddox, Pippert, and Sullivan, whose results "indicate a statistically significant inverse relationship between interest rates and utility equity risk premiums." Mr. Proctor's view that the method is not based on a sound theory or model simply is

[125] Direct Testimony of James M. Proctor, at 57.

[126] Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, The Risk Premium Approach to Measuring a Utility's Cost of Equity, Financial Management (Spring 1985), at 43.

incorrect – it is based on a theory, and a model, supported by published financial literature and research.

Lastly, as noted earlier, Mr. Proctor and Mr. Watson point to FERC as support for their use of the "two-step" DCF method. FERC, however, now believes the Bond Yield Plus Risk Premium approach should be among the four methods used to estimate the Cost of Equity.[127]

Q50. DOES YOUR BOND YIELD PLUS RISK PREMIUM MODEL PROVIDE EMPIRICALLY MEANINGFUL RESULTS?

A. Yes, it does. As shown in Chart 1 (page 37) of my Revised Direct Testimony, the model's R^2 is about 74.00 percent, and the inverse relationship between the Equity Risk Premium and the 30-year Treasury yield is statistically significant at the 99.00 percent confidence level. That is, changes in interest rates explain about 74.00 percent of the change in authorized ROEs. If Mr. Proctor believes other variables should be included in the analysis, he has not explained what they are, or how they would contribute to the remaining 26.00 percent of explanatory value needed to produce a perfect statistical fit.

To help put the model's explanatory value in perspective, I calculated the R^2 associated with the Beta coefficient for each company in Mr. Proctor's proxy group. As Mr. Proctor is aware, Value Line calculates its Beta coefficients using linear regression analysis, in which the subject company's return is the dependent variable, and the market return is the independent variable. Although Value Line does not provide the R^2 for its

[127] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 18. Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 17.

Beta coefficients, I was able to replicate the calculation based on Value Line's convention (weekly returns, using the New York Stock Exchange Index as the market index). As ENO Exhibit RBH-27 demonstrates, the average R^2 for Mr. Proctor's group is 6.80 percent. That is, whereas the explanatory value of my Bond Yield Plus Risk Premium method is 74.00 percent, the average explanatory value of Mr. Proctor's Beta coefficients is less than 7.00 percent.[128]

Q51. EARLIER YOU REFERRED TO FOUR METHODS THAT THE FERC HAS PROPOSED TO ESTIMATE THE COST OF EQUITY. WHAT IS THE FOURTH METHOD THE FERC HAS PROPOSED TO ESTIMATE THE COST OF EQUITY?

A. In addition to the two-step DCF approach, the CAPM, and the Bond Yield Plus Risk Premium approach, the FERC has proposed using the Expected Earnings approach.[129] The Expected Earnings approach calculates the projected returns on book value for the electric industry group as a whole and for the specific firms in the proxy group individually. The Expected Earnings approach is based on the intuitively simple concept that when faced with alternative investments of comparable risk, investors will choose that with the higher expected return. In that fundamental sense it is consistent with the economic principle of opportunity costs, and the *Hope* and *Bluefield* "comparable risk" standard.

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[128] By pointing out that difference, I am not suggesting the CAPM should not be used.

[129] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 18. Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 17.

Q52. HAVE YOU PREPARED AN EXPECTED EARNINGS ANALYSIS FOR YOUR PROXY GROUP?

A. Yes, I have. To do so, I gathered the three-to-five year projected earned Return on Common Equity[130] from the latest Value Line report for each proxy company. I adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[131] That analysis indicates a median Cost of Equity of 10.52 percent, which is within my recommended range and supports the conclusion that the Advisors' ROE Witnesses' 8.93 percent recommendation is well below a reasonable estimate of the Company's Cost of Equity.

G. Business Risk Adjustment

Q53. PLEASE BRIEFLY SUMMARIZE MR. PROCTOR'S PROPOSED BUSINESS RISK ADJUSTMENT.

A. Mr. Proctor does not appear to disagree with the proposition that the Company is risker than its peers. In his view, "its geographic location, its small size, and its propensity to incur significant storm damage"[132] is reason to provide a return in excess of his CAPM estimates. To arrive at his estimate, Mr. Proctor calculates the standard deviation of his proxy group's Beta coefficient (9.33 percent), which he multiplies by his estimated

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[130] For the projected period 2021-2023, or 2022-2024. *See* ENO Exhibit RBH-20.

[131] The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. *See*, Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

[132] Direct Testimony of James M. Proctor, at 61.

Market Risk Premium (8.70 percent), producing an adjustment of 81 basis points.[133] Mr. Proctor believes the sum of his CAPM estimate (7.57 percent), his business risk adjustment (0.81 percent), and his flotation cost adjustment (discussed below; 0.03 percent), 8.42 percent, is a reasonable estimate of the Company's Cost of Equity.[134]

Q54. DO YOU AGREE WITH MR. PROCTOR'S APPROACH AND CONCLUSIONS?

A. No, I do not. Earlier I addressed Mr. Proctor's view that 8.42 percent is a reasonable estimate of the Company's Cost of Equity; I will not repeat those arguments here. Those points aside, I fundamentally disagree with the method by which Mr. Proctor developed his estimate.

Q55. WHY DO YOU DISAGREE WITH MR. PROCTOR'S METHOD?

A. In my view, Mr. Proctor's approach captures statistical variation among the proxy companies' Beta coefficients; it is not a measure of fundamental business risk. Even if it were, there is no particular reason why one standard deviation is the proper adjustment. As Mr. Proctor's Exhibit No.__(JMP-9) demonstrates, at the (approximately) 95.00 percent confidence level, the Beta coefficient adjustment would be 1.62 percent, for an adjusted ROE estimate of 9.20 percent.[135] What Mr. Proctor fails to consider is that even at that higher confidence level, his method would produce a result near the lowest ROE

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133 9.33% x 8.70% = 0.81%. *See* Direct Testimony of James M. Proctor, at 61.

134 Direct Testimony of James M. Proctor, at 12 – 13; 61–63.

135 (0.7797 – 0.5931) x 8.70% = 1.62%; 9.20% = (0.78 x 8.70%) + 2.41%

authorized since at least 1980 for a vertically integrated electric utility.[136] That is, even with a risk adjustment two times Mr. Proctor's proposal, the effect would be an ROE that suggests risk among the very lowest of utilities, not among the highest.

Moreover, in applying Mr. Proctor's approach it is difficult to disentangle the effect of the variation among the proxy companies' Beta coefficients and the statistical properties of individual Beta coefficients. As noted earlier, Beta coefficients tend to have relatively low R^2 values (market returns tend to explain relatively low proportions of changes in company-specific returns). A statistical reality is that with low R^2 values come relatively high standard errors (*see*, ENO Exhibit RBH-27). Consequently, what Mr. Proctor attributes to incremental business risk may be not much more than random error.

Those practical points aside, Mr. Proctor's method runs counter to financial research. For example, Mr. Proctor argues his adjustment is meant to capture, among other things, the Company's relatively small size. As discussed in my Revised Direct Testimony, however, Beta coefficients do not reflect the risks associated with small size.[137] I explained that published research has found stock returns are better explained as a function of variables such as size and Market/Book values *in addition to* the single-factor Beta coefficient. Based on data provided by Duff & Phelps, I calculated the size premium alone to be 101 basis points.[138]

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136 The lowest authorized ROE for a vertically integrated electric utility since 1980 is 9.00 percent. Source: Regulatory Research Associates.

137 Revised Direct Testimony of Robert B. Hevert, at 53.

138 *Ibid*., at 53–54. *See* ENO Exhibit RBH-11.

That 101-basis point adjustment does not address the span of incremental risks Mr. Proctor identifies - it addresses the Company's relatively small size, only. One means of capturing the additional return associated with those additional risks is to recognize, as the Advisors' ROE Witnesses do, that geographic location and storm risk are two factors driving Moody's below investment grade rating for ENO.[139] With that point in mind, I reviewed the incremental return required on below investment grade utility debt relative to investment grade debt. Based on data from Bloomberg Professional, since February 2018, the difference in yields on 30-year utility bonds rated within the BBB ratings categories, and utility bonds rated below investment grade (in the BB ratings category) has been about 220 basis points.[140]

Although I believe equity return requirements would be much higher than spreads in the bond market, if we simply use this measure and Mr. Proctor's 7.57 percent unadjusted return, the corresponding Cost of Equity would be approximately 9.77 percent (7.57 percent plus 2.20 percent). Even then, the result is about the same as the average authorized ROE. If we assume the 220-basis point adjustment does not reflect the risks associated with small size, the result would be 10.78 percent (9.77 percent plus 1.01 percent).

I appreciate there may be some overlap between the 220-basis point credit spread and my 101-basis point small size adjustment, such that they are not necessarily

139 Direct Testimony of Byron S. Watson, at 25–26; Direct Testimony of James M. Proctor, at 61.

140 Source: Bloomberg Professional.

additive.[141] As noted earlier, however, equity investors bear the residual risk of ownership in perpetuity. And although below investment grade debt has risks greater than its investment grade counterparts, it still has protections not available to equity investors, and a priority claim on cash flows relative to equity investors. Consequently, the Cost of Equity would increase more than the cost of debt, such that the combined 321-basis point adjustment (to Mr. Proctor's 7.57 percent unadjusted result) would be a reasonable estimate of the Company's ROE (and just three basis points above my 10.75 percent recommendation).

Q56. HAVE YOU CONSIDERED OTHER MEASURES OF THE INCREMENTAL RETURN ASSOCIATED WITH THE RISKS MR. PROCTOR OBSERVES?

A. Yes, I have. Rather than using the standard deviation of Beta coefficients within Mr. Proctor's proxy group, I reviewed the Beta coefficients of companies with characteristics corresponding to the Company's below-investment grade rating. To do so, I developed a comparison group of companies that (1) are classified by Value Line as operating in the Electric Utility, Power, or Diversified Natural Gas industries, and (2) have Financial Strength Ratings (also by Value Line) of "B+" or lower.

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141 Moody's refers to the Company's "small and concentrated service territory in a low-lying coastal region" as a "credit challenge". *See* Moody's Investors Service, Credit Opinion, *Entergy New Orleans, Inc.*, October 13, 2017.

Q57. WHY DID YOU APPLY THOSE SPECIFIC CRITERIA?

A. First, Value Line is a widely recognized source of financial information, covering industry sectors that are relevant to this analysis. Second, Value Line's "Financial Strength Rating" considers several factors including "[b]alance sheet leverage, business risk, the level and direction of profits, cash flow, earned returns, cash, corporate size, and stock price", each of which is an important consideration to equity investors. By selecting companies operating in the electric utility and energy industries, with Financial Strength Ratings similar to ENO's, we are able to develop a group whose Beta coefficients reasonably reflect the risks associated with a below investment grade credit rating.

Q58. WHY DID YOU SELECT COMPANIES WITH FINANCIAL STRENGTH RATINGS OF "B+" OR LOWER?

A. I did so because the lowest Financial Strength rating of any company in the Value Line Electric Utility universe is "B+". Of the five Electric Utility companies with a B+ Financial Strength rating, only Pacific Gas and Electric, however, has a below investment grade rating from either S&P or Moody's.[142]

As shown in Table 3 below, the average Beta coefficient for all companies (within the sectors noted above) with Financial Strength Ratings of "B+" or lower is 1.12; the average for companies with "B+" ratings is also 1.12. In both cases, the average was quite near the median and the skew was negligible.

142 Those four companies include CenterPoint Energy, Edison International, Pacific Gas & Electric Company, PNM Resources, and Unitil, Inc.

Table 3: Average, Median Beta Coefficients[143]

OVERALL	Average	1.12
	Median	1.15
	Std. Dev.	0.72
	Skew	0.01
	Count	107
FSR = B+	Average	1.12
	Median	1.20
	Std. Dev.	0.49
	Skew	0.20
	Count	21

I considered 1.10 a conservative estimate of the Beta coefficient for companies with Financial Safety Ratings of B+. The difference between 1.10 and Mr. Proctor's proxy group average Beta coefficient (0.59) is 0.51 which, when multiplied by Mr. Proctor's Market Risk Premium (8.70 percent) produces an incremental equity return requirement of 4.44 percent. Adding that additional return to Mr. Proctor's unadjusted CAPM result (7.57 percent) suggests an adjusted ROE of 12.01 percent.[144]

Q59. ARE YOU SUGGESTING THAT THE COMPANY'S ROE SHOULD BE SET AT 12.01 PERCENT?

A. No, I continue to recommend 10.75 percent. The analyses discussed above, however, demonstrate that Mr. Proctor's CAPM estimate and proposed business risk adjustment do not reasonably reflect ENO's Cost of Equity. There is no reasonable means of

143 Source: Value Line.

144 12.01% = (0.51 x 8.70%) + 7.57%

reconciling an ROE of 8.38 percent – including his 81-basis point business risk adjustment – with the data and methods frequently used to determine the Cost of Equity.

H. Additional ROE Considerations

Tax Cuts and Jobs Act

Q60. PLEASE BRIEFLY SUMMARIZE MR. PROCTOR'S POSITION REGARDING THE TCJA'S EFFECT ON THE COMPANY'S COST OF EQUITY.

A. Mr. Proctor raises two arguments. First, he suggests "if" there is any increase in risk associated with the TCJA it would be industry-wide and reflected in his and Mr. Watson's analyses.[145] Second, Mr. Proctor believes "any over-all negative impact from the TCJA of 2017 on ENO's business risk is short-lived and immaterial".[146]

Q61. WHAT IS YOUR RESPONSE TO MR. PROCTOR ON THOSE POINTS?

A. As to Mr. Proctor's first argument, it is important to recall that all models produce ranges of results.[147] The important analytical consideration is whether there are factors that may help determine where the Cost of Equity likely falls within those ranges. As discussed below, the TCJA is one such factor. Regarding his second point, my Revised Direct Testimony noted that because utilities cannot benefit from the TCJA in ways other

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145 Direct Testimony of James M. Proctor, at 45–46.

146 *Ibid*., at 46.

147 For example, Mr. Watson's unadjusted Two-Step DCF results produce a range of 5.74 percent to 10.64 percent. *See* Exhibit No.__(BSW-4), Page 1.

industries can, utilities became less attractive relative to other industry sectors.[148] That change in valuation has been meaningful, and longer-lived than Mr. Proctor supposes.

Third, the TCJA will affect each company differently and rating agencies are evaluating how each has addressed these effects. Moody's stated it would "continue to monitor the financial impact of tax reform on each company, including its regulatory approach to rate treatment",[149] which suggests likewise treatment by equity investors.

Q62. ARE THERE EMPIRICAL METHODS THAT CAN BE USED TO ASSESS THE EFFECT OF AN EVENT SUCH AS THE TCJA ON UTILITY STOCK PERFORMANCE?

A. Yes, a method frequently used is an "event study", or a "cumulative abnormal return" analysis. To understand whether a specific event affected stock prices, it is important to control for factors beyond the event under consideration. The portion of the stock's return that is not attributable to those other factors is considered the "abnormal" or "excess" return; the sum of those excess returns is the "cumulative" abnormal return.

To apply that approach, I defined the abnormal return on a given day as:

$$A_t = R_{i,t} - R_{m,t} \quad [3]$$

[148] Revised Direct Testimony of Robert B. Hevert, at 59–60.

[149] Moody's Investors Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform,* January 19, 2018.

where A_t is the Abnormal Return on day t, $R_{i,t}$ is the actual return for the proxy group[150] on day t, and $R_{m,t}$ is the expected return for the proxy group defined in Equation [4] below.

$$R_{m,t} = \alpha_t + \beta_{m,t} \qquad [4]$$

The expected return, $R_{m,t}$, (sometimes referred to as the "market-adjusted return") is based on a regression equation in which Mr. Watson's proxy group's daily returns[151] are the dependent variable, and the market's daily return (measured by the S&P 500 Index) is the explanatory variable. Because it relies on market-adjusted returns, the approach controls for factors that, like the TCJA, affect companies across market sectors. Consistent with Value Line's approach for calculating Beta coefficients, I applied the regression (*i.e.*, Equation [4]) over five years, using daily (rather than weekly) returns. The equation and slope coefficient both were statistically significant (*see* Table 4, below).

Table 4: Market Model Regression Statistics

	Slope	**Intercept**
Coefficient	0.3803	0.0002
Std. Err.	0.0293	0.0002
R-Square	0.1180	
F-Stat	168.3746	
t-Stat	12.9759	0.974

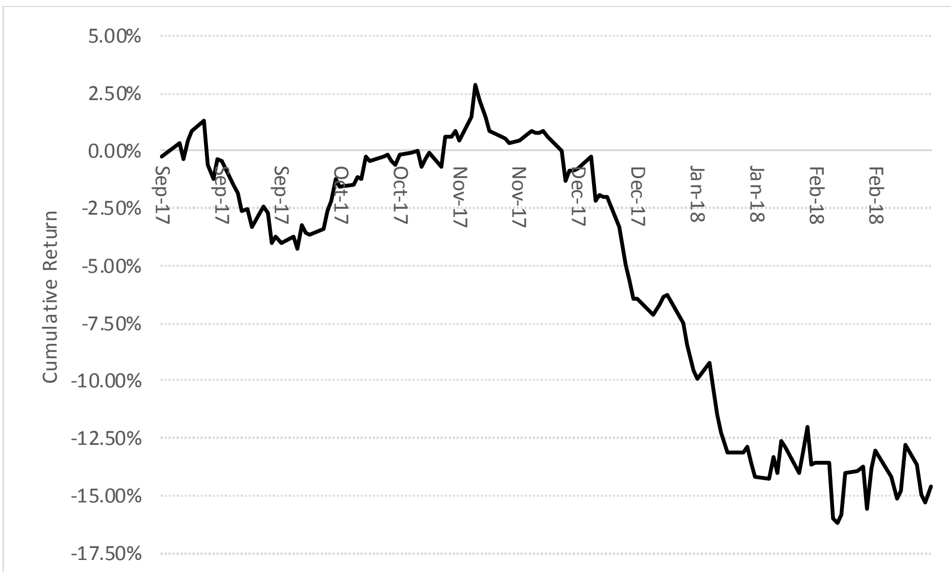
To determine whether the TCJA likely affected the proxy companies' stock valuations, I considered the "event date" to be December 1, 2017. Because it pre-dates the TCJA's enactment, the event date provides for the likelihood that equity investors

150 Calculated as an index. Source: S&P Global Market Intelligence.

151 Calculated as an index. Source: S&P Global Market Intelligence.

were aware of, and began to consider how the TCJA may affect utility risks before the TCJA became law. I then calculated the cumulative abnormal return for each day over a window that spanned from September 1, 2017 to March 1, 2018 (that is, approximately three months before and after December 1, 2017). Chart 10 (below) provides the cumulative abnormal return over that period (*i.e.*, negative 15.27 percent).

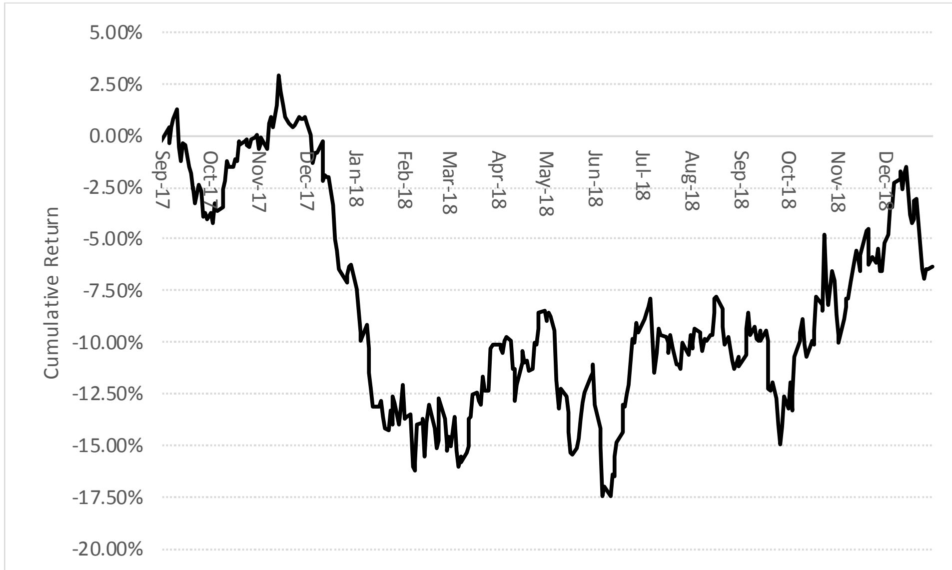
Chart 10: Mr. Watson's Proxy Group Cumulative Abnormal Return[152]



To consider Mr. Proctor's view that the TCJA's effect over time is "immaterial", I extended the post-event window to December 31, 2018. Even in that case, with the effect of intervening events, the abnormal return remained well below zero (*see* Chart 11, below).

[152] Source: S&P Global Market Intelligence. Based on a t-test, the cumulative abnormal returns are statistically significant.

Chart 11: Cumulative Abnormal Return Extended[153]



Q63. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. Controlling for market-wide events, the TCJA has had a strong negative effect on Mr. Proctor's proxy group; that effect has continued over time. We therefore reasonably can conclude that aside from actions taken by rating agencies, the TCJA meaningfully – and negatively – affected utility stock prices, and should be considered in determining the Company's ROE.

153 Source: S&P Global Market Intelligence. Based on a t-test, the cumulative abnormal returns are statistically significant.

Implications of the Formula Rate Plan and Other Rate Mechanisms

Q64. PLEASE SUMMARIZE MR. PROCTOR'S POSITION REGARDING VARIOUS RATE STRUCTURES AND THEIR EFFECT ON THE COMPANY'S CREDIT PROFILE AND COST OF CAPITAL.

A. Mr. Proctor argues that the Company's "favorable ratemaking considerations, separately and collectively, decreases regulatory lag" which "should provide ENO enhanced financial credit metrics and sustain or improve its credit profile."[154]

Q65. WHAT IS YOUR RESPONSE TO MR. PROCTOR ON THOSE POINTS?

A. I disagree. Mr. Proctor's argument appears to be that revenue stabilization mechanisms *necessarily* are credit enhancing – that they materially improve the utility's financial integrity, thereby reducing its cost of capital. He fails to consider that rate structures such as the Formula Rate Plan are more likely to be credit supportive – helping utilities maintain their credit profiles in the face of countervailing forces. That is, but for the rate structures, the utility's credit profile would come under pressure, likely increasing its cost of capital. Even if it were the case that revenue stabilization mechanisms mitigate some measure of "risk," they would affect the Company's Cost of Equity only if: (1) the effect of the mechanism was to reduce the Company's risk below that of its peers; and (2) investors knowingly reduced their return requirements as a direct consequence of the mechanisms.

[154] Direct Testimony of James M. Proctor, at 26.

Q66. DOES FINANCIAL THEORY REQUIRE A REDUCTION IN THE COST OF EQUITY IN CONNECTION WITH STRUCTURES SUCH AS THE FORMULA RATE PLAN?

A. No, it does not. As Mr. Proctor recognizes, in Modern Portfolio Theory (which forms the basis of the CAPM) risk is defined as the uncertainty, or variability, of returns. Modern Portfolio Theory was advanced by recognizing that total risk may be separated into two distinct components: non-diversifiable risk, which is that portion of risk that can be attributed to the market as a whole; and non-systematic (or diversifiable) risk, which is attributable to the idiosyncratic nature of the subject company, itself. As discussed in my Revised Direct Testimony, non-diversifiable risk is measured by the Beta coefficient within the CAPM structure.[155]

Under Modern Portfolio Theory (and the CAPM) an investor would not be indifferent to a reduction in expected ROE in return for the implementation of rate structures unless those structures specifically reduce non-diversifiable risk. That is, any reduction in the Cost of Equity depends on the type of risk that is reduced; if the risk assumed to be mitigated by the rate structures is diversifiable, there would be no reduction in the Cost of Equity even if total risk (diversifiable plus non-diversifiable risk) has been reduced. If, however, rate structures mitigate increased systematic risk associated with the factors that drove their implementation in the first place, there likewise would be no effect on the Cost of Equity. Mr. Proctor assumes, but does not demonstrate, any risks he believes to be mitigated by the Company's rate structures are systematic in nature, that systematic risk was not increased before the structures were

155 Revised Direct Testimony of Robert B. Hevert, at 30–31.

implemented and, therefore that the rate structures necessarily reduce the Company's Cost of Equity.

Lastly, under the "comparable risk" standard and the economic principle of opportunity costs, the Cost of Equity cannot be considered in isolation, it must be viewed on a comparative basis. Putting aside his disregard of Modern Portfolio Theory, Mr. Proctor simply has not shown the Company would be so less risky than its peers that its Cost of Equity would be 8.42 percent.

Flotation Cost Adjustment

Q67. PLEASE SUMMARIZE MR. PROCTOR'S RECOMMENDATION REGARDING FLOTATION COSTS.

A. Mr. Proctor agrees an adjustment for flotation costs is reasonable, although he suggests I have calculated the approximately nine basis point adjustment based on flotation costs of 1.12 percent of gross equity issuance proceeds. As noted in ENO Exhibit RBH-12, however, the applicable flotation cost rate is 2.525 percent; it is that rate which produces the nine-basis point adjustment. In any event, Mr. Proctor argues flotation costs should be calculated net of taxes, and recommends an adjustment of three basis points.[156]

Q68. DO YOU AGREE WITH MR. PROCTOR'S APPROACH AND CONCLUSIONS?

A. No, I do not. First, as noted above the appropriate flotation cost rate is 2.525 percent, which represents the weighted average rate over several years and across many

[156] Direct Testimony of James M. Proctor, at 62–63.

companies. Because equity has an indefinite life, the flotation costs adjustment should reflect the best estimate of issuances costs "of various vintages and types of equity capital."[157]

Second, I disagree with Mr. Proctor's view that the flotation cost rate should be calculated on a tax-effected basis. Flotation costs are not operating expenses and are not recovered through the Company's revenue requirement. Even if they were, the recovery would be of the cost itself (amortized over some period). Rather, flotation costs are a permanent reduction in equity capital; the adjustment that Mr. Proctor adopts reflects that position. That method, which is consistent with that recommended by Dr. Morin, does not consider income taxes. But even if we did make a tax adjustment, the flotation cost would be about six basis points, not nearly enough to bring Mr. Proctor's ROE recommendation to a reasonable level.

Double Leverage Adjustment

Q69. PLEASE SUMMARIZE MR. WATSON'S PROPOSED "DOUBLE LEVERAGE" ADJUSTMENT TO THE COMPANY'S CAPITAL STRUCTURE.

A. Mr. Watson argues a utility engages in "double leverage" when it borrows debt at the parent level "and places that money into its utility subsidiaries as common equity providing a potential return which is likely greater than its original borrowed cost."[158] In his view, the fact that the parent company (Entergy Corporation) has more debt than its utility operating subsidiaries is evidence of "double leverage", requiring the imposition of

[157] Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 337.

[158] Direct Testimony of Byron S. Watson, at 51.

a hypothetical capital structure.[159] Mr. Watson reasons that "allowing ENO rates reflective of an equity ratio of 52.2% when the Entergy Corp. equity ratio is 34.1% would constitute double leverage."[160]

As discussed below, extended to its logical conclusion, Mr. Watson's theory would require every operating subsidiary to be financed in the same proportions as the parent, in this case, with 34.10 percent common equity. But he does not make that recommendation, recognizing that doing so "reasonably might not be considered prudent."[161] On that point, we agree. Instead, Mr. Watson concludes that "a reasonable estimate of Entergy's benefit at ratepayer expense from ENO's double leverage is closer to $1.5 million and $0.3 million annually for electric and gas respectively based on the average non-ENO EOC equity ratio."[162]

In summary, Mr. Watson appears to believe Entergy Corporation has engaged in "double leverage", which would require a 34.10 percent equity ratio for ratemaking purposes. But he chooses not to go that far, concluding the proper average equity ratio for other Entergy Corporation operating utilities is 50.00 percent.[163]

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159 *Ibid*.

160 *Ibid*.

161 *Ibid*., at 54.

162 *Ibid*.

163 *Ibid*., at 55.

Q70. DO YOU AGREE WITH MR. WATSON'S CONCLUSIONS?

A. No, I do not. As discussed below, Mr. Watson's approach is internally inconsistent, not supported by basic financial theory, removed from regulatory practice, and would have the unintended effect of increasing risks to investors and costs to ratepayers.

Q71. TURNING TO YOUR FIRST POINT, WHY DO YOU BELIEVE MR. WATSON'S RECOMMENDATION IS INTERNALLY INCONSISTENT?

A. Double leverage cannot be not a matter of degree. Here, Mr. Watson argues the parent company has borrowed at debt cost rates and invested that capital in subsidiaries' equity. That argument assumes, however, that cash is not fungible, that it can be traced from its source (the borrowed debt) to its use (invested equity). If that is the case, there is only one outcome: The 34.10 percent parent company equity ratio must be applied to all Entergy utility operating companies.

Simply, if Mr. Watson's capital structure recommendation is predicated on his finding of double leverage, he should not recommend anything but 34.10 percent. In addressing that point, the Arkansas Public Service Commission noted that the issue at hand was whether "certain liabilities can be specifically identified and associated with certain assets",[164] noting the testimony of Staff witness Dr. Berry, who stated that:

> You either think fungibility is appropriate, or you don't. You don't draw the line and say, 'Well, certain liabilities are fungible, but certain other liabilities are not.' It's either all or nothing with fungibility.[165]

164 Arkansas Public Service Commission, Docket No. 84-199-U, Order No. 7, at 12.

165 *Ibid*., at 13.

By recommending a 50.00 percent equity ratio, Mr. Watson effectively has assumed fungibility can be partially applied.

Q72. PLEASE NOW EXPLAIN WHY YOU BELIEVE MR. WATSON'S ARGUMENT IS NOT SUPPORTED BY FINANCIAL THEORY.

A. Mr. Watson's position rests on three assumptions that are not supported in finance theory: (1) every dollar of external capital raised by the parent company can be specifically traced to an eventual use, (2) all subsidiaries can and should be financed in the same proportions as the parent, and (3) the return required on an investment depends on the source of funds, not on the risks attendant to the investment, itself.

As to the first assumption, Mr. Watson has provided no information regarding how individual sources of capital raised at the parent level were invested in ENO, or any other Entergy Corporation subsidiary. That he did not do so is not surprising; it is a long-held understanding in corporate finance that cash is fungible and cannot be traced to specific uses. In that regard, the Federal Power Commission noted "[i]t is generally impossible to specifically trace the source of funds used for various corporate purposes…"[166] Similarly, the New Hampshire Public Service Commission stated that:

> We find that sound principles of finance caution against any attempt to 'track' dollars raised by a company to any specific purpose. A firm raises capital in a variety of ways, trying always to achieve an overall balance of sources to minimize its cost of money.[167]

[166] United States Federal Power Commission, Order No. 561, February 2, 1977, at 2.

[167] New Hampshire Public Utilities Commission, DT 02-110, Order No. 24,625, January 1, 2004.

Regarding the second assumption, Mr. Watson's reference to the parent company capital structure runs counter to the widely accepted practice of applying the "stand-alone" approach, which treats each utility subsidiary as its own company. Under the stand-alone approach, the cost of capital is determined using the subsidiary's capital structure and cost of debt and equity; the Cost of Equity is estimated by reference to a proxy group of firms of comparable risk. As discussed further below, the stand-alone approach recognizes that the return should be based on the relative risk of the investment rather than the source of financing. That is, the Cost of Equity is the risk-adjusted opportunity cost to the investors and not the cost of the specific capital sources being employed by investors.

Under the stand-alone approach, ownership does not affect the operating utility's capital structure or cost of capital. Parent entities, like other investors, have capital constraints and must consider the attractiveness of the expected risk-adjusted return of each investment alternative as part of their capital budgeting process. The opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to the firm to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with its affiliates and with other, similarly situated utility companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return. It therefore is important that the authorized capital structure reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective.

The stand-alone approach has been long-supported in published financial literature. In a 1983 article in The Journal of Financial Research, Pettway and Jordan found:

> No valid support for the "double leverage" approach is found after an analysis of descriptive examples and a general theoretical examination of the two approaches compared against established goals of rate of return regulation. The "independent company" approach is shown to be universally correct. The authors suggest, therefore, that only the "independent company" approach should be employed in rate of return cases of regulated public utilities whose parents own subsidiaries with unequal risk and/or whose parent has its own debt.[168]

The use of the operating subsidiary's actual capital structure – the capital funding the utility plant and equipment that enables utility service – also is consistent with FERC's precedent, under which the commission prefers to use the applicant's capital structure, where possible.[169] In particular, FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the commission.[170] FERC noted that if those conditions are not met, it may apply the consolidated capital structure. In those cases, "[u]se of the parent's market driven capital structure when the operating company's own capital structure is outside the range of reasonable capital structures ensures that the

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[168] Richard H. Pettway, Bradford D. Jordan, *Diversification, Double Leverage, and the Cost of Capital*, The Journal of Financial Research, Vol. VI, No. 4, Winter 1983, at 289. Please note, the authors use the terms "independent company" and "stand alone" interchangeably.

[169] *See Transcontinental Gas Pipe Line Corp,* 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

[170] 148 FERC ¶ 61,049 Docket No. EL14-12-000, at 190.

operating company receives a reasonable return, while also protecting ratepayers against higher rates resulting from equity ratios outside the reasonable range."[171] FERC also noted that it does not apply a specific cap to the equity ratio. Rather, the commission stated that:

> [we] recognize that a utility may consider a range of factors beyond simple capital cost minimization in developing their capital structures. Such considerations include, but are not limited to, managing risk and cash flow.

FERC therefore has recognized that the capital structure is fundamentally tied to the assets being financed, and to the nature of utility operations.

Lastly, imposing the parent company's capital structure on the subsidiary assumes all the subsidiary's equity was provided by the parent. That clearly is not the case; retained earnings are derived from the subsidiary's operations. In the case of ENO, as of 2017 approximately $190.40 million of its $415.50 Total Proprietary Capital (or 45.80 percent) was derived from retained earnings.[172]

Q73. PLEASE DISCUSS MR. WATSON'S THIRD IMPLICIT ASSUMPTION, THAT THE REQUIRED RETURN ON AN INVESTMENT DEPENDS ON ITS SOURCE OF FUNDS.

A. As noted earlier, Mr. Watson believes debt raised at the parent level has been used to finance equity investments at the subsidiary level, "providing a return which is likely

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171 148 FERC ¶ 61,049 Docket No. EL14-12-000, at 191.

172 Entergy New Orleans, LLC FERC Form 1, as of 2017/Q4, at 112.

greater than its original borrowed cost."[173] Because investors tend to be risk averse, the return they require depends on the risk of the investment, not the source of capital used to fund the investment.

Under Mr. Watson's construct, the required return depends on the source of financing, not on the risks of the underlying utility operations. Two utilities identical in all respects but for their form of ownership should have the same cost rates. The position that a company would have a different value depending on how investors fund their equity investments violates the widely acknowledged economic "law of one price", which states that in an efficient market, identical assets would have the same value.

That discussion suggests a second point: If the common equity of a subsidiary were held by both the parent and an external investor, the equity held by the parent would have one required return, and the equity held by outside investors would have another. To the extent required returns differed, so would the value of the equity. But in an efficient market, identical assets must have the same price (value). If not, the difference quickly would be arbitraged away. As Dr. Morin notes:

> Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to

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173 Direct Testimony of Byron S. Watson, at 51.

> common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different and the double leverage adjustment shouldn't obscure this fact.[174]

Further to that point, the Maryland Public Service Commission specifically rejected the use of double leverage in a 2007 rate proceeding, stating:

> We reject People's Counsel's proposed capital structure [reflecting a double leverage adjustment] because it suffers from numerous flaws. First, it assumes that the rate of return depends on the source of capital rather than the risks faced by the capital.[175]

Q74. LASTLY, WHY DO YOU BELIEVE MR. WATSON'S RECOMMENDATION WOULD HAVE THE EFFECT OF INCREASING THE COST OF CAPITAL?

A. I believe that is the case for two reasons. First, it would require more financial leverage (debt) in the Company's capital structure, creating additional financial risk and, therefore, increasing the cost of capital. As Brigham and Gapenski point out, "…the use of debt, or financial leverage, concentrates the firm's business risk on its stockholders."[176] Financial leverage and the cost of capital therefore are inextricably related; as financial risk increases, so does the Cost of Equity. Mr. Watson's recommendation to increase financial leverage therefore would put upward pressure on the Company's cost of capital.

Second, as noted earlier, 50.00 percent of the factors Moody's considers in arriving at credit rating determinations relate to the nature of regulation, and the regulatory environment. Here, the Company's proposed capital structure is highly

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174 Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 524.

175 Maryland Public Service Commission, Order No. 81517, Case No. 9092, In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rate and Charges for Electric Service and for Certain Rate Design Changes, July 19, 2007. [clarification added].

176 Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 1994, The Dryden Press, at 528.

consistent with industry practice; as discussed in my Revised Direct Testimony, the proxy group average equity ratio has been 53.15 percent,[177] somewhat higher than the Company's proposed 52.20 percent equity ratio. If the City Council were to adopt Mr. Watson's recommendation, the increased debt leverage not only would erode cash flow-related credit metrics, it would introduce an element of regulatory risk that certainly would be of concern to both debt and equity investors. In that case, the costs of debt and equity would increase.

IV. RESPONSE TO AIR PRODUCTS WITNESS WALTERS

Q75. PLEASE SUMMARIZE MR. WALTER'S RECOMMENDATION REGARDING THE COMPANY'S COST OF EQUITY.

A. Mr. Walters recommends an ROE of 9.35 percent, within a range of 9.00 to 9.70 percent.[178] Mr. Walters establishes his recommended ROE by reference to: (1) his constant growth DCF model using both consensus analyst growth rates and a sustainable growth rate (with median and average results ranging from 7.69 percent to 9.30 percent);[179] (2) his Multi-Stage DCF method (with median and mean results of 7.67 percent and 7.78 percent, respectively);[180] (3) his Risk Premium study (ranging from 9.60 percent to 9.70 percent);[181] and (4) his CAPM analyses (ranging from 7.30 percent to

177 See ENO Exhibit RBH-13; updated to 53.44 percent in ENO Exhibit RBH-21.

178 Direct Testimony of Christopher C. Walters, at 3.

179 *Ibid*., at 36.

180 *Ibid*., at 36.

181 *Ibid*., at 42.

8.20 percent).[182] Mr. Walters' 9.35 percent recommendation represents the approximate midpoint of his DCF (9.00 percent) and Risk Premium (9.70 percent) analyses.[183]

Q76. WHAT ARE THE PRINCIPAL ANALYTICAL AREAS IN WHICH YOU DISAGREE WITH MR. WALTERS?

A. The principal areas in which I disagree with Mr. Walters include: (1) the effect of market conditions and utility risk profiles on the Company's Cost of Equity; (2) the application of the Constant Growth DCF model, and interpretation of its results; (3) the application of the Multi-Stage DCF model; (4) the Market Risk Premium component of his CAPM analysis, in particular the expected market return from which the Market Risk Premium is calculated; (5) the assumptions and methods underlying Mr. Walters' Risk Premium analyses; and (6) Mr. Walters' assessment of the Company's relative risk.

A. Market Conditions and Utility Risk Profiles

Q77. WHAT IS YOUR RESPONSE TO MR. WALTERS' OBSERVATION THAT UTILITIES RESPRESENT A "LOW RISK"[184] INVESTMENT?

A. If Mr. Walters' point is that utilities are less risky than the broad market, there is no dispute; the fact that utilities tend to have Beta coefficients less than 1.00 shows that to be the case. At the same time, the average Beta coefficient for Mr. Walters' proxy group is

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182 *Ibid*., at 48.

183 *Ibid*., at 49.

184 *Ibid*., at 81.

0.60,[185] suggesting a meaningful degree of risk. For example, in 2008, when the market lost about 40.00 percent of its value, the SNL Electric Company index lost about 27.00 percent of its value.[186] In fact, from September through December 2008, when the overall market lost about 28.00 percent of its value, the correlation between the SNL Electric Company Index and the S&P 500 averaged approximately 80.00 percent.[187] That is, when the capital markets became increasingly distressed, utility valuations also decreased, much like the overall market, but not to the same extent.

Q78. MR. WALTERS REFERS TO SEVERAL RECENT REPORTS BY S&P, MOODY'S, AND FITCH, CONCLUDING THAT THE CURRENT RATING OUTLOOK FOR REGULATED UTILITIES IS STABLE.[188] DO YOU HAVE A RESPONSE TO MR. WALTERS ON THAT POINT?

A. Yes. I recognize that Mr. Walters referred to certain of the rating agency reports discussed in my Revised Direct Testimony. He notes those reports discuss the uncertainties surrounding the implications of tax reform,[189] a point also discussed in my Revised Direct Testimony.[190]

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185 Source: Schedule CCW-15, *Ibid*., at 44.

186 Source: S&P Global Market Intelligence.

187 Source: S&P Global Market Intelligence. Based on daily returns. Correlations calculated over rolling three-month periods.

188 Direct Testimony of Christopher C. Walters, at 9–11.

189 *Ibid.*, at 10.

190 Revised Direct Testimony of Robert B. Hevert, at 62–63.

Q79. WHAT ARE SOME OF THE POTENTIAL IMPLICATIONS OF RATING AGENCY COMMENTS REGARDING UTILITY CAPITAL EXPENDITURES?

A. Mr. Walters' Figure 2 demonstrates that utility capital investment has "increased considerably" and is expected to "remain high" in the 2018-2020 forecast period relative to the prior ten-year historical period.[191] All three rating agencies have observed the negative effects of the TCJA on utilities' cash flow and the potential consequences for their credit profiles;[192] Moody's did so as recently as June 2018. It therefore is clear that continued access to external capital at reasonable rates will be important to fund capital expenditures, as Mr. Walters observes.[193] It also is clear that the markets in which that capital will be raised reflect higher expected interest rates and greater volatility than those experienced even over the past two years.[194]

Q80. DO YOU HAVE ANY OBSERVATIONS REGARDING THE ANNUAL AVERAGE AUTHORIZED RETURNS DISCUSSED IN PAGES 4-5 OF MR. WALTERS' DIRECT TESTIMONY?

A. Yes, I do. Average annual data obscures variation in returns and does not address the number of cases or the jurisdictions issuing orders within a given year. For example, one year may have fewer cases decided, and a relatively large portion of those cases decided

[191] Direct Testimony of Christopher C. Walters., at 7–8.

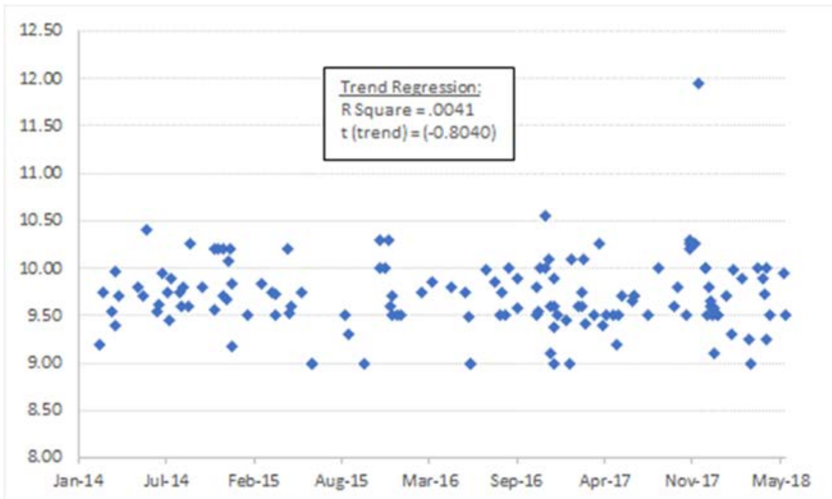
[192] Revised Direct Testimony of Robert B. Hevert, at 61-62.

[193] Direct Testimony of Christopher C. Walters, at 75.

[194] The median value of the VIX, which measures expected market volatility over the coming 30 days, was 10.85 in 2017, and 17.00 in 2019, indicating a material increase in volatility. By June 2020, the VIX is expected to increase to 18.95. Source: cboe.com, accessed March 8, 2019.

by a single jurisdiction. As shown in Chart 12, if all authorized ROEs are charted, rather than the simple average, there is no meaningful trend since 2014; time explains less than 1.00 percent of the change in ROEs, and the trend is statistically insignificant.

Chart 12: Electric Authorized Returns (2014-2019)[195]



From a slightly different perspective, the recent fluctuations around the annual average authorized return data are well within the standard deviation of authorized ROEs, as shown in Table 5, below.

Table 5: Mean and Standard Deviation of Authorized Returns (2014-2019)[196]

Year	Average	Standard Deviation
2014	9.78%	0.30
2015	9.64%	0.38
2016	9.66%	0.35
2017	9.74%	0.48
2018	9.60%	0.32

195 Source: Regulatory Research Associates. Excludes limited issue rate riders and ROEs authorized as part of the Illinois formula rate proceedings.

196 Source: Regulatory Research Associates. Excludes limited issue rate riders and ROEs authorized as part of the Illinois formula rate proceedings.

From that perspective as well, there is no reason to conclude authorized returns have fallen since 2014.

Mr. Walters also argues that "the most frequent distribution of authorized equity returns is less than 9.7%".[197] In support of his argument, he presents the distribution of authorized ROEs for the years 2016, 2017, and 2018 in his Table 1. However, Mr. Walters' Table 1 includes authorized ROEs for electric distribution utilities, including ROEs authorized under the Illinois Formula Rate proceedings.[198] If Mr. Walters' Table 1 were revised to present the statistics for only vertically integrated electric utilities, the result would demonstrate that (1) the mean was 9.75 percent, (2) the median was 9.70 percent, and (3) a majority of authorized ROEs were 9.70 percent and higher (*see* Table 6 below).

Table 6: Distribution of Authorized ROEs: Vertically Integrated Electric Cases[199]

Year	Average	Median	Share of Decisions 9.70% and Higher
2016	9.77%	9.78%	55.00%
2017	9.80%	9.65%	46.43%
2018	9.68%	9.75%	59.09%
Total	9.75%	9.70%	52.86%

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[197] Direct Testimony of Christopher C. Walters, at 5. I note that Mr. Walters' Table 1 presents the share of decisions authorizing an ROE "less than or equal to 9.70 percent", rather than ROEs authorized less than 9.70 percent.

[198] In Illinois, statute requires the ROEs for Commonwealth Edison and Ameren Illinois to be re-set annually, under a formula rate plan ratemaking paradigm where the allowed ROE is set by application of a 580 basis-point premium to the 12-month average 30-year Treasury Bond yield. In the historically low interest rate environment, this framework has resulted in the lowest ROEs in at least 30 years. Source: RRA.

[199] Source: Regulatory Research Associates. Excludes limited issue rate riders.

B. Constant Growth DCF Model

Q81. AS A PRELIMINARY MATTER, DOES MR. WALTERS GIVE HIS CONSTANT GROWTH DCF RESULTS ANY WEIGHT IN ARRIVING AT HIS 9.35 PERCENT ROE RECOMMENDATION?

A. Yes. As noted earlier, Mr. Walters' 9.35 percent recommendation represents the approximate midpoint of his 9.00 percent to 9.70 percent recommended range. The lower bound of Mr. Walters' range (9.00 percent) is based on his DCF results, and the upper bound (9.70 percent) is based on his Risk Premium results. [200] To arrive at his DCF-based recommendation, Mr. Walters gives primary weight to his Constant Growth DCF model results based on analysts' growth rate projections (8.86 percent to 9.30 percent), but notes he "also considers the results of [his] other DCF models."[201]

Q82. DO YOU HAVE ANY CONCERNS WITH THE CONSTANT GROWTH DCF MODEL IN GENERAL AND THE WEIGHT MR. WALTERS APPLIES TO THOSE RESULTS IN PARTICULAR?

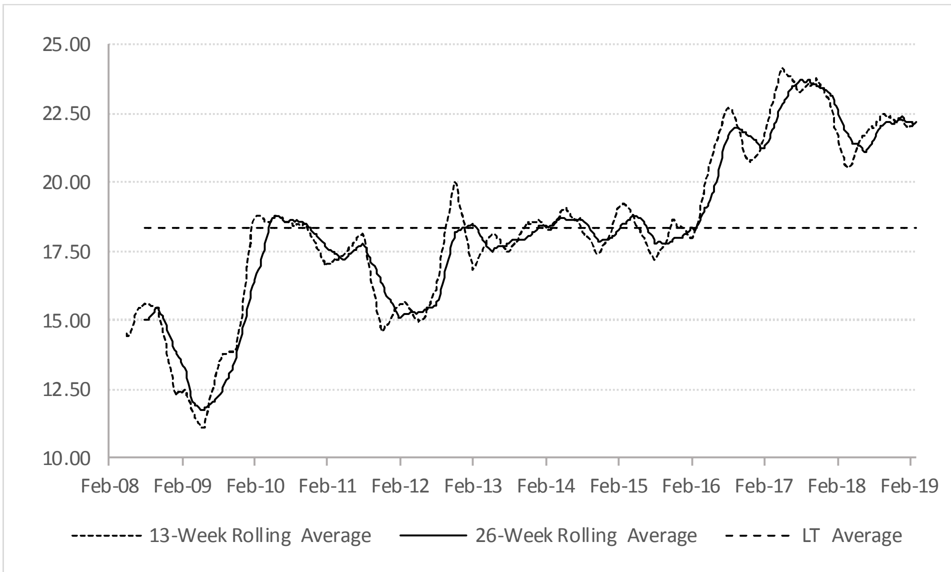
A. Yes, I do. In addition to the reasons discussed in Section II, the Constant Growth DCF model is based on several underlying assumptions establishing an inverse relationship between expected growth and the dividend yield. Under those assumptions, as higher growth produces higher prices, and lower dividend yields. Conversely, lower growth produces lower prices, and higher dividend yields. Contrary to those fundamental

[200] Direct Testimony of Christopher C. Walters, at 49.

[201] *Ibid*., at 38. Clarification added.

assumptions, Mr. Walters' Constant Growth DCF analysis applies historically high valuations (*see* Chart 13, below), but comparatively low growth rates.

Chart 13: Mr. Walters' Proxy Group Rolling Average P/E Ratio[202]



As Mr. Walters acknowledges, unsustainable expansions in P/E ratios create analytical concerns. For example, at pages 46-47 of his Direct Testimony, Mr. Walters discusses the Market Risk Premium component of his CAPM and explains Ibbotson & Chen's finding regarding an "abnormal expansion" of P/E ratios relative to earnings and dividend growth. Because higher P/E ratios were not explained by higher growth in earnings or dividends, Ibbotson and Chen's analyses required adjustments.[203] Duff & Phelps, the source referenced by Mr. Walters, provides that adjustment using three-year average P/E ratios, rather than relying on the current year, because "the three-year average allows the adjustment to smooth out the volatility of extraordinary events and

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[202] Source: S&P Global Market Intelligence. Rolling 13-week and 26-week average.

[203] Direct Testimony of Christopher C. Walters, at 47, citing Duff & Phelps 2018 Valuation Handbook, at 3-43.

allows earnings to better reflect a normalized trend."[204] Duff & Phelps recognized that the long-term trend of the level of P/E ratios is important, and that abnormally high P/E ratios will produce questionable analytical results.

The same conditions hold here. As shown in Chart 13, the utility sector has undergone an "abnormal expansion" in P/E ratios, which should not be expected to remain constant in perpetuity. Consequently, Constant Growth DCF results reflecting abnormal capital market conditions should be viewed with caution and given less weight. Whereas Duff & Phelps recognized and adjusted its analyses to reflect the abnormal expansion in P/E ratios, Mr. Walters' DCF analyses, and his interpretation of their results, do not. In short, I disagree with Mr. Walters' conclusions and continue to believe less weight should be given to the Constant Growth DCF model under current market circumstance.

C. Application of the Multi-Stage DCF Model

Q83. DO YOU AGREE WITH MR. WALTERS' APPLICATION OF THE MULTI-STAGE DCF MODEL?

A. No, I do not. Mr. Walters' Multi-Stage DCF model contains several assumptions that produce unreasonably low ROE estimates. In particular, Mr. Walters' model assumes a perpetual growth rate beginning in the eleventh year of his model (that is, beginning in calendar year 2029) based on a GDP growth rate projection that actually ends in 2029.[205]

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[204] Duff & Phelps, 2018 Valuation Handbook, at 3-44.

[205] *See* Direct Testimony of Christopher C. Walters, at 29, 33 and Schedule CCW-9; *see also* and Blue Chip Financial Forecasts, December 1, 2018 at 14.

In addition, Mr. Walters assumes all dividends are received at year-end, rather than over the course of the year.

Q84. HOW DOES MR. WALTERS' ASSUMPTION AS TO THE TIMING OF DIVIDEND PAYMENTS UNREASONABLY DECREASE HIS MULTI-STAGE DCF MODEL RESULTS?

A. Mr. Walters notes that quarterly dividends in his Constant Growth DCF model were "annualized (multiplied by 4)."[206] Considering that Mr. Walters' proxy companies pay dividends on a quarterly basis, assuming (as Mr. Walters has done) that the entire dividend is paid at the end of that year essentially defers the timing of the quarterly cash flows (that is, the quarterly dividends) until year-end, even though they are paid throughout the year. A reasonable method of reflecting the timing of quarterly dividend payments is to assume cash flows are received in the middle of each year (*i.e.*, the "mid-year convention"). As Duff & Phelps notes:

> Common practice in business valuation is to assume that the net cash flows are received on average continuously throughout the year (approximately equivalent to receiving the net cash flows in the middle of the year), in which case the present value factor is generally based on a mid-year convention (e.g., (1+k)0.5).[207]

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206 Direct Testimony of Christopher C. Walters, at, at 23. Mr. Walters applies the same annualized dividend in his Multi-Stage DCF model.

207 Duff & Phelps, 2016 Valuation Handbook, Guide to Cost of Capital at 1-4.

Q85. WOULD MR. WALTERS' MULTI-STAGE DCF RESULTS BE DIFFERENT IF HE APPLIED THE MID-YEAR CONVENTION?

A. Yes. ENO Exhibit RBH-28, which replicates Mr. Walters' Schedule CCW-9, demonstrates that his model assumes year-end cash flows. As ENO Exhibit RBH-28 also demonstrates, simply changing the dividend timing to reflect the mid-year convention increases the mean and median results by approximately 13 basis points (from 7.78 percent and 7.67 percent, to 7.91 percent and 7.80 percent, respectively). Even with that change, however, Mr. Walters' model produces results too low to be reasonable estimates of the Company's Cost of Equity.

Q86. PLEASE FURTHER EXPLAIN YOUR CONCERN WITH THE LONG-TERM GROWTH RATE IN MR. WALTERS' MULTI-STAGE DCF MODEL.

A. The long-term growth rate represents the expected rate of growth, in perpetuity, as of the beginning of the third, or terminal, stage. It is an important parameter, given that it accounts for more than 70.00 percent of the model's results.[208] Mr. Walters' assumed terminal growth rates is not consistent with his model's structure, nor is it consistent with measures of growth noted elsewhere in his testimony.

208 *See* ENO Exhibit RBH-28.

Q87. TURNING TO YOUR SECOND POINT, HOW DOES MR. WALTERS' ASSUMED 4.19 PERCENT GDP GROWTH RATE CONFLICT WITH OTHER ASPECTS OF HIS ANALYSES?

A. In his Table 7, Mr. Walters presents the results of his various analyses, including his 8.20 percent CAPM estimate. That estimate relies, in part, on a Market Risk Premium of 7.70 percent, which is based on an expected market return of 11.30 percent.[209] As shown in ENO Exhibit RBH-16, the current expected market dividend yield is approximately 2.10 percent, suggesting an expected growth rate of about 9.20 percent (11.30 percent - 2.10 percent). At pages 29-30 of his testimony, Mr. Walters compares utility earnings growth rates to his expected GDP growth rate, concluding that one should correlate to the other. If that is the case, Mr. Walters' CAPM analysis assumes economic growth could be as high as 9.20 percent, well in excess of the 4.19 percent growth rate he uses to assess my estimates.

Q88. HAVE YOU CONSIDERED HOW MR. WALTERS' MULTI-STAGE DCF RESULTS WOULD CHANGE IF IT INCLUDED A TERMINAL GROWTH RATE IN THE RANGE OF 9.20 PERCENT?

A. Yes. Rather than assume 9.20 percent, I solved for the terminal growth rate that would produce mean and median ROE estimates of about 9.55 percent, consistent with the 2018 average authorized ROE provided in Mr. Walters' Schedule CCW-11. I then considered that terminal growth rate relative to the 9.20 percent growth rate associated with Mr.

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209 Schedule CCW-16; Direct Testimony of Christopher C. Walters, at 45.

Walters' expected market return. As ENO Exhibit RBH-28 demonstrates, using Mr. Walters' Multi-Stage DCF model (including the mid-year convention), a terminal growth rate of 6.26 percent produces mean and median ROE estimates of 9.61 percent and 9.50 percent, respectively (average of 9.55 percent). That growth rate (6.26 percent) falls below the midpoint of the 4.19 percent and 9.20 percent growth rates assumed in Mr. Walters' other analyses (that midpoint being 6.70 percent). It also falls below the long-term average nominal GDP growth rate of 6.34 percent reported by the Bureau of Economic Analysis. Assuming the 6.70 percent midpoint as the terminal growth rate produces an average ROE estimate of about 9.97 percent, well above Mr. Walters' 9.35 percent recommendation.

Q89. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. Adjusting Mr. Walters' Multi-Stage DCF model to reflect growth rates associated with other aspects of his analyses produces ROE estimates consistent with returns authorized in other jurisdictions, and closer to my recommended range.

D. Application of the CAPM

Q90. PLEASE BRIEFLY SUMMARIZE MR. WALTERS' CAPM ANALYSIS AND RESULTS.

A. Mr. Walters' two CAPM estimates (7.30 percent and 8.20 percent) are based on two measures of principally historical Market Risk Premium estimates, *Blue Chip Financial Forecasts*' projected 30-year Treasury yield of 3.60 percent as the risk-free rate and an average Beta coefficient of 0.60 as reported by Value Line.[210] Based on his assessment of risk premiums in the current market, Mr. Walters relies on the high-end 8.20 percent CAPM.[211] Mr. Walters' analyses assume Market Risk Premium estimates of 7.70 percent (based on the long-term historical arithmetic average real market return from 1926 through 2017 as reported by Duff & Phelps, adjusted for current inflation forecasts) and 6.10 percent (based on the historical difference between the average return on the S&P 500 and the average total return on long-term government bonds).[212] Combining those Market Risk Premium estimates with his projected long-term risk-free rate, Mr. Walters develops expected market returns in the range of 9.70 percent to 11.30 percent.[213]

Q91. TURNING FIRST TO THE EXPECTED TOTAL MARKET RETURN, DO YOU AGREE WITH MR. WALTERS' 9.70 PERCENT AND 11.30 PERCENT ESTIMATES?

A. No, I do not. As a practical matter, Mr. Walters' 9.70 percent expected total market return estimate, which is 236 basis points below the long-term average market return, falls outside the range of average returns during the period 1976-2017 using 50-year annual averages; his higher 11.30 percent estimate falls in the bottom 22nd percentile of the average return over the last fifty years.[214] A helpful perspective on the historical

[210] *Ibid*., at 48 and Schedule CCW-16.

[211] *Ibid*., at 48.

[212] *Ibid*., at 45 and Schedule CCW-16.

[213] *Ibid*., Mr. Walters' low Market Risk Premium of 6.10 percent plus his projected risk-free rate of 3.60 percent equals an estimated market return of 9.70 percent.

[214] Rolling average basis.

market return is the rolling 50-year average annual market return. As Mr. Walters points out, from 1926 through 2017 the arithmetic average market return was 12.10 percent.[215] Over time, the rolling fifty-year mean return has been quite consistent, in the range of approximately 12.00 percent.[216] Taken from that perspective, Mr. Walters' 9.70 percent expected market return is well below the long-term market experience and, therefore, is not reasonable.

Q92. DO YOU AGREE WITH MR. WALTERS' USE OF THE HISTORICAL AVERAGE MARKET RISK PREMIUM?

A. No. For the reasons discussed in my response to the Advisors' Witness Mr. Proctor, I do not agree that the historical average Market Risk Premium is appropriate for the CAPM.

E. Application of the Risk Premium Model

Q93. PLEASE BRIEFLY DESCRIBE MR. WALTERS' RISK PREMIUM ANALYSES.

A. Mr. Walters defines the "Risk Premium" as the difference between average annual authorized equity returns for electric utilities and a measure of long-term interest rates each year from 1986 through 2018.[217] Mr. Walters' first approach calculates the annual risk premium by reference to the 30-year Treasury yield, and his second approach considers the average A-rated utility bond yield.[218] In each case, Mr. Walters establishes

[215] Direct Testimony of Christopher C. Walters, at 45.

[216] Source: Duff & Phelps 2018 SBBI Yearbook, Appendix A-1.

[217] Direct Testimony of Christopher C. Walters, at 37.

[218] *Ibid*., Schedules CCW-11 and CCW-12.

his risk premium estimate by reference to five-year and ten-year rolling averages. The lower and upper bounds of Mr. Walters' Risk Premium range are defined by the lowest and highest rolling average, respectively, regardless of the year in which those observations occurred.[219]

Regarding the period over which he gathers and analyzes his data, Mr. Walters argues his 33-year horizon is "appropriate"[220] for developing an Equity Risk Premium estimate. On page 39 of his Direct Testimony, Mr. Walters further states "it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns" and concludes his risk premium study is based on "investor expectations, not actual investment returns, and, thus, need not encompass a very long historical time period."[221] Based on those assumptions, Mr. Walters calculates a range of risk premium estimates of 4.25 percent to 6.72 percent using his Treasury bond analysis, and 2.88 percent to 5.57 percent using his A-rated utility bond analysis.[222]

Combined with a 3.60 percent projected Treasury yield, a 4.44 percent A-rated utility bond yield estimate, and a 4.96 percent Baa-rated utility bond yield estimate, Mr. Walters' Risk Premium analysis produces results ranging from 7.32 percent to 10.53 percent.[223] To calculate his Risk Premium-based ROE recommended range, Mr. Walters

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219 *Ibid*., at 38, Schedules CCW-11 and CCW-12.

220 *Ibid*., at 39.

221 *Ibid*., at 40.

222 Schedules CCW-11 and CCW-12.

223 4.44% + 2.88% = 7.32%; 4.44% + 5.57% = 10.01%; 4.96% + 2.88% = 7.84%; 4.96% + 5.57% = 10.53%; 3.60% + 4.25% = 7.85%; 3.60% + 6.72% = 10.32%.

gives 75.00 percent weight to the high end of his risk premium estimates and 25.00 percent to the low end. The 9.60 percent low end of his Risk Premium-based range reflects his weighted risk premium estimates using the 13-week average utility bond yields of 4.44 percent and 4.96 percent.[224] Applying the same 75.00 percent and 25.00 percent weighting to his high and low Treasury yield estimates, respectively, Mr. Walters produces the upper bound of his range of 9.70 percent.[225] Mr. Walters then concludes that upper bound of his range (9.70 percent) is the appropriate Risk Premium-based ROE estimate.[226]

Q94. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING MR. WALTERS' RISK PREMIUM ESTIMATES AND HOW THEY WEIGH IN HIS OVERALL ROE RECOMMENDATION?

A. Yes, I do. In assessing his DCF analyses, Mr. Walters relied on his highest results, effectively discarding several other results that ranged from 7.67 percent to 7.92 percent.[227] Similarly, in assessing his CAPM analysis, Mr. Walters relied on his high-end result, discarding an 7.30 percent estimate.[228] In his Risk Premium analysis, however, Mr. Walters retained risk premiums that produced ROE estimates below the DCF and CAPM estimates he discarded. Despite their low levels, Mr. Walters gave those risk

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224 Direct Testimony of Christopher C. Walters, at 41-42. 9.60% = (0.125 x 7.32%) + (0.125 x 7.84%) + (0.375 x 10.01%) + (0.375 x 10.53%)

225 Direct Testimony of Christopher C. Walters, at 41-42; 9.70% = (0.25 x 7.85%) + (0.75 x 10.32%)

226 *Ibid*., at 42.

227 *Ibid*., at 36.

228 *Ibid*. at 48.

premium estimates (producing ROE results of 7.32 percent, 7.84 percent, and 7.85 percent) weights of 25.00 percent in aggregate. Mr. Walters offers no explanation as to why he would exclude DCF results of 7.92 percent and lower, yet include Risk Premium results of 7.32 percent, 7.84 percent, and 7.85 percent. The effect of including his low Risk Premium results is to reduce his ROE range.

Q95. WHAT ARE YOUR SPECIFIC CONCERNS WITH MR. WALTERS' RISK PREMIUM ANALYSIS?

A. I have three concerns with his analysis: (1) Mr. Walters' method understates the required risk premium in the current market because it ignores an important relationship confirmed by his own data, *i.e.,* that the risk premium is inversely related to the level of interest rates (whether measured by Treasury or utility bond yields); (2) the low end of Mr. Walters' Risk Premium results is far lower than any ROE authorized since at least 1986 and, as such, has no relevance in estimating the Company's Cost of Equity; and (3) Mr. Walters suggests that a Market/Book ("M/B") ratio of 1.00 is a relevant benchmark for assessing authorized ROEs.[229]

[229] *Ibid*., at 37–38.

Q96. TURNING FIRST TO THE ISSUE OF M/B RATIOS, DO YOU AGREE WITH MR. WALTERS THAT M/B RATIOS SHOULD BE USED TO ASSESS THE REASONABLENESS OF ROE RECOMMENDATIONS?

A. No. Although Mr. Walters frames his discussions in the context of authorized returns "sufficient to support market prices that at least exceeded book value,"[230] he does not suggest whether the M/B ratio should exceed some level or even explain the relationship between authorized returns and M/B ratios.

The M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book equity) per share. Book value per share is an accounting construct, which reflects historical costs. In contrast, market value per share (*i.e.*, the stock price) is forward-looking, and a function of many variables, including (but not limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.

Q97. ARE YOU AWARE OF ANY PUBLISHED RESEARCH THAT ADDRESSES THE ISSUE OF M/B RATIOS IN THE CONTEXT OF THE CONSTANT GROWTH DCF MODEL?

A. Yes. As Branch *et al.* point out, the M/B ratio generally is greater than or equal to one because the value of the firm as a going concern (price per share) generally exceeds the liquidation value (book value per share) and "…firms having going concern values

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[230] *Ibid*.

greater than their liquidation values (most firms) and firms having finite prices (all firms) should have ROE > R> G."[231] Taken from that perspective M/B ratios in excess of unity should not be surprising; if the liquidation value exceeds the market value, the company would be liquidated.

Q98. HAVE M/B VALUES GENERALLY EXCEEDED 1.00 FOR THE BROAD EQUITY MARKET?

A. Yes, they have. As Chart 14 (below) demonstrates, since 1990 the average M/B ratio for the S&P 500 Index has been 2.87; it has never reached unity.

Chart 14: S&P 500 Market/Book Ratio Over Time[232]

If investors, over many years and across many companies, felt that the returns they expected had so significantly exceeded the returns they required, they would adjust their requirements.

231 Branch *et al.* (2014), at 18. [clarification added] Here, R = the Cost of Equity, and G = growth.

232 Source: Bloomberg Professional.

That finding also is consistent with U.S. Generally Accepted Accounting Principles ("GAAP") and International Financial Reporting Standards, which require firms to carry the value of assets on their books at the historical cost of those assets. Only under specific circumstances may the value of certain financial investments be carried at market value.[233] As a result:

> …given market efficiency, the [M/B] ratio is intrinsically an accounting phenomenon; that is, on first order, [M/B] is determined by how accountants measure book value… If all assets and liabilities were accounted for using unbiased mark-to-market or "fair value" accounting, [M/B] would be equal to unity for all levels of risk….A good example is a pure investment fund where "net asset value" typically equals market value, since accountants apply mark-to-market accounting to these funds….For most other firms, accountants do not mark the net assets involved with operations to market. The application of historical cost accounting, exacerbated by the application of conservative accounting, introduces a difference between price and book value.[234]

Q99. ARE YOU AWARE OF RESEARCH FOCUSING ON THE M/B RATIOS OF REGULATED UTILITIES?

A. Yes, such research has long concluded that regulation may not necessarily result in M/B ratios approaching unity. As noted by Phillips in 1993:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.'[235]

[233] Financial Accounting Standards Board Rule 157.

[234] S. H. Penman, S.A. Richardson, and I. Tuna, "*The Book-to-Price Effect in Stock Returns: Accounting for Leverage*", Journal of Accounting Research, 45:2, May 2007. The authors use the reciprocal of the M/B and different notation. In the quote above, I have replaced B/P (where P denotes price per share) with M/B for ease of exposition.

[235] Charles F. Phillips, The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) at 395.

In 1988 Bonbright stated:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the Company they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels. [236]

As noted by Stewart Myers in 1972:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that market and book values will be equal. This is an obvious but important point. *If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital*. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book [emphasis added].[237]

Lastly, as Dr. Morin states, it is rarely the case in cost of service-based regulation that M/B ratios equal 1.00:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s whose utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is

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[236] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), at 334.

[237] *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366, citing Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 76.

> applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[238]

Q100. WHAT WOULD BE THE RESULT IF REGULATORY COMMISSIONS DID FORCE M/B RATIOS TOWARD UNITY?

A. Looking to Mr. Walters comparison group, the average capital loss for equity investors would be about 51.30 percent.[239] That loss would not just affect investors, it also would substantially diminish the ability of utilities to attract external capital. To summarize, if regulatory commissions were to set rates with an eye toward moving the M/B ratio toward unity, that practice may well impede the ability to attract the capital required to support its operations, especially in markets during which the M/B ratio for the overall market is significantly greater than 100.00 percent.

Q101. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THIS ISSUE?

A. Yes. It is important to keep in mind that in practice, the M/B ratio is used as a measure of relative, not absolute valuation. That is, it typically is used by investors to assess the value of an asset or enterprise relative to the prevailing M/B ratios of comparable assets or enterprises. Its use as a measure of relative value simply reflects the practical understanding that no one model, including the present value structure that underlies the Constant Growth DCF model, should be relied on as the sole measure of value.

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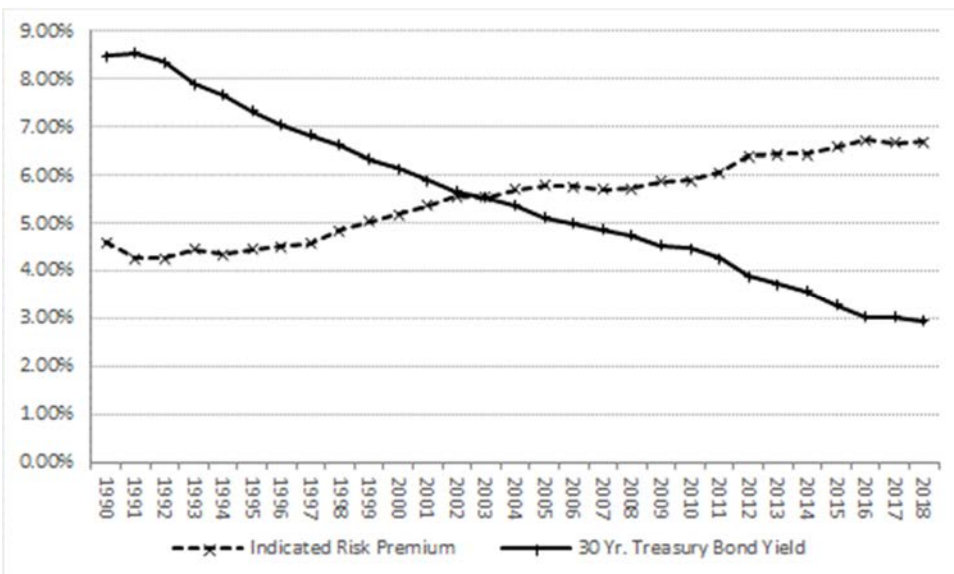
238 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 434. [emphasis added]

239 Based on Mr. Walters' proxy group 2018 average M/B ratio of 205.40. (205.40-100)/205.40 = 51.31 percent. Schedule CCW-6, page 2.

Q102. WHAT DID YOUR ANALYSIS OF MR. WALTERS' RISK PREMIUM ANALYSES INDICATE?

A. Because Mr. Walters failed to consider the inverse relationship between interest rates and the Equity Risk Premium, his Risk Premium ROE estimates are biased downward. Considering first the Treasury yield-based analysis, I plotted the yields and Risk Premia over the 1986 to 2018 period included in Mr. Walters' analysis. Chart 15 (below) clearly indicates the inverse relationship between interest rates and the Equity Risk Premium, based on Mr. Walters' data.

Chart 15: Mr. Walters' Treasury Yield-Based Risk Premium Data[240]



There are several other points made clear in Chart 15. First, the low end of Mr. Walters' Risk Premium range, 4.25 percent, was observed in the five-year period ending 1991. There is little question that Risk Premium estimates associated with economic environments 28 years ago have little to do with current market conditions. For example,

240 Schedule CCW-11; based on five-year rolling average.

prior to 2002, Treasury yields exceeded the Risk Premium (on a five-year average basis). As Chart 15 (*see also* ENO Exhibit RBH-29) demonstrates, since then, the opposite has been true – the Risk Premium has consistently exceeded Treasury yields. It therefore is clear that the low end of Mr. Walters' range has little, if any, relevance to the current market environment.

The high end of Mr. Walters' range, 6.72 percent, occurred more recently (for the five-year period ending 2016). In fact, as Schedule CCW-11 indicates, Mr. Walters' Equity Risk Premium averaged approximately 6.75 percent over the more recent period from 2015 through 2018.[241] Adding that 6.75 percent Equity Risk Premium to Mr. Walters' projected Treasury yield of 3.60 percent produces an ROE estimate of 10.35 percent, within my recommended ROE range.

Q103. HAS THE RISK PREMIUM INCREASED AS TREASURY YIELDS HAVE DECREASED?

A. Yes. The relationship between the five-year average Equity Risk Premium and Treasury yields is very clear. A simple linear regression demonstrates the two are highly related, with a Coefficient of Determination (R-Square) of approximately 96.50 percent (*see* Chart 16, below).[242]

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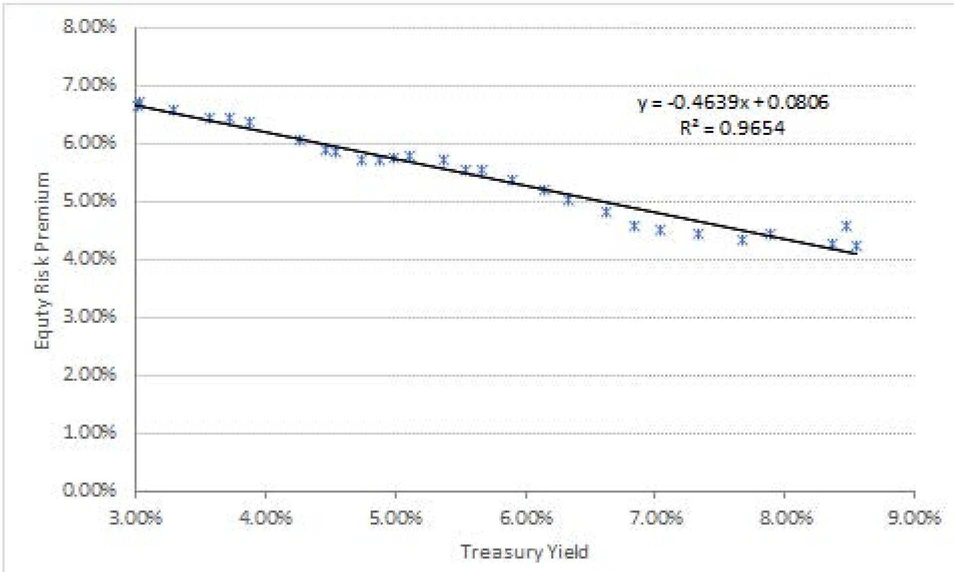
241 Based on Indicated Risk Premium.

242 Those findings are supported in academic studies. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when rates fell and declining when interest rates rose." Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006 at 128 [clarification added]

Chart 16: Treasury Yield vs. Equity Risk Premium

(Five-Year Rolling Average)[243]



Turning back to Mr. Walters' data, a simple linear regression analysis using annual (rather than the rolling-average data) demonstrates that for every 100-basis point decrease in Treasury yields, the Equity Risk Premium increases by approximately 44 basis points (*see* ENO Exhibit RBH-30).[244] Similarly, the Equity Risk Premium increases approximately 45 basis points for every 100-basis point decrease in utility bond yields. Those results are consistent with those reported by Maddox, Pippert, and Sullivan, who determined that the Risk Premium would increase by 37 basis points for every 100-basis point change in the 30-year Treasury yield.[245]

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243 *See* ENO Exhibit RBH-30. Source: Schedule CCW-11.

244 Serial correlation is not present at the 1% significance level.

245 *See* Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Vol. 24, No. 3, Autumn 1995 at 93.

Contrary to Mr. Walters' position, accounting for additional factors, such as credit spreads (taken from Mr. Walters' exhibits), does not change the sign, statistical significance, or the magnitude of the slope coefficient.[246]

Q104. WHAT ARE YOUR CONCLUSIONS REGARDING MR. WALTERS' RISK PREMIUM ANALYSIS?

A. Mr. Walters' use of rolling average estimates analysis does not negate the effect of his reliance on outdated and unrepresentative data, and the conclusions he draws from that data. Although he argues more variables are at play, Mr. Walters' own data strongly support the finding that the Equity Risk Premium is inversely related to interest rates. Taking that finding into account leads ROE estimates of nearly 10.00 percent, relative to his 9.35 percent recommendation.[247]

F. Response to Mr. Walters' Criticisms of Company Analyses

Q105. PLEASE SUMMARIZE MR. WALTERS' CRITICISMS OF YOUR COST OF EQUITY ANALYSES.

A. Mr. Walters asserts my estimated ROE is overstated and should be rejected because (1) my Constant Growth DCF results are based on unsustainably high growth rates; (2) my Multi-Stage DCF is based on an "unrealistic" long-term growth rate, a "manipulated" dividend payout ratio, and "unjustified" terminal P/E ratio assumptions; (3) my CAPM is based on inflated estimates of the Market Risk Premia; and (4) my Bond Yield Plus Risk

[246] *See* ENO Exhibit RBH-30.

[247] *See*, *for example*, ENO Exhibit RBH-29, which present a range of results from 9.71 percent to 9.99 percent.

Premium is based on an inflated utility Equity Risk Premium.[248] Additionally, Mr. Walters asserts that ENO's business risks are captured in its credit rating and that a flotation cost adjustment is not appropriate.[249]

Q106. DOES MR. WALTERS HAVE ANY CONCERNS WITH YOUR PROXY GROUP?

A. Although he accepts most companies in my proxy group, Mr. Walters is critical of NextEra Energy, Inc. ("NextEra") and Southern Company ("Southern"), due to a transaction between the two companies in which Next Era acquired Gulf Power Company and Florida City Gas from Southern.[250]

Q107. DO YOU AGREE THAT THE TRANSACTION BETWEEN NEXTERA AND SOUTHERN IS SIGNIFICANT ENOUGH TO WARRANT THEIR REMOVAL FROM THE PROXY GROUP?

A. No, I do not. The purchase of Gulf Power Company and Florida City Gas from Southern Company ("Southern") is not transformative to the buyer or seller, either in terms of relative market capitalization or operations. As Mr. Walters notes:

> M&A activity can distort the market factors used in DCF and risk premium studies. M&A activity can have impacts on stock prices, growth outlooks, and relative volatility in historical stock prices if the market was anticipating or expecting the M&A activity prior to it actually being announced. This distortion in the market data thus

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248 Direct Testimony of Christopher C. Walters, at 51.

249 *Ibid*., at 60–64.

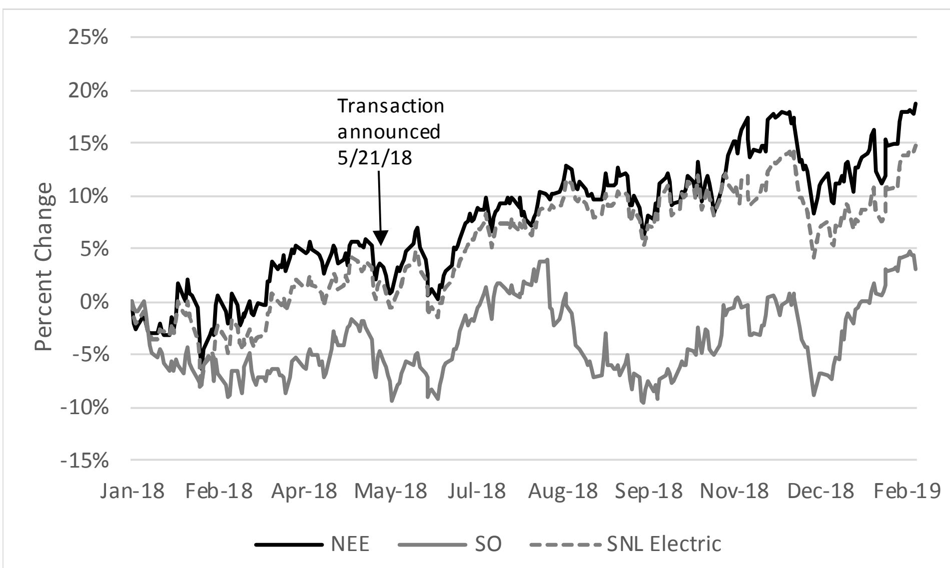
250 *Ibid*,, at 20.

> impacts the reliability of the DCF and risk premium estimates for a company involved in M&A.[251]

I agree with Mr. Walters on those points. However, Mr. Walters has not provided any evidence to demonstrate NextEra and Southern's market factors were "distorted" by the transaction. As shown in Chart 17 below, there was no significant effect on the stock prices of the two companies at the time of the announcement. Over the last year (with the exception of early August due to Southern's announcement of increased project costs at its Vogtle nuclear plant[252]), NextEra and Southern have generally traded consistent with other electric utilities (as measured by the SNL Electric Index). Consequently, I have kept NextEra and Southern in my proxy group.

Chart 17: Stock Price Change in NextEra and Southern

(January 2018 – February 2019)[253]



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[251] *Ibid*.

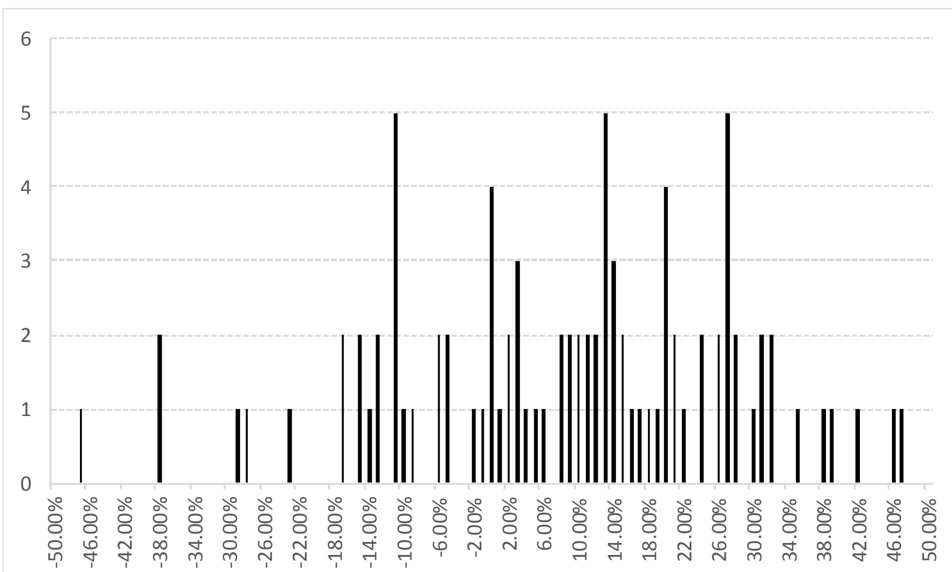
[252] *See, e.g.*, Regulatory Research Associates, "Southern CEO: Vogtle nuke write-off is 'short-term pain, but long-term gain'," August 8, 2018.

[253] Source: S&P Global Market Intelligence.

Q108. ARE THE GROWTH RATES USED IN YOUR CONSTANT GROWTH DCF ANALYSIS "UNSUSTAINABLY HIGH"?

A. No, they are not. A capital appreciation rate of 5.67 percent (*i.e.*, the average growth rate in the Constant Growth DCF analysis in my Revised Direct Testimony) and higher has occurred quite often (*see* Chart 18 below).[254] That is, Chart 18 shows the number of times historical observations have been in certain ranges. The growth rates Mr. Walters asserts are "unsustainably high" by historical standards represent approximately the 42nd percentile of the actual capital appreciation rates observed from 1926 to 2017.

Chart 18: Frequency Distribution of Capital Appreciation Returns, 1926-2017[255]



254 Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation.

255 Duff & Phelps, 2018 SBBI Yearbook, at A-3.

Q109. PLEASE RESPOND TO MR. WALTERS' ASSERTION THAT YOUR MULTI-STAGE DCF LONG-TERM GROWTH RATE IS INCONSISTENT WITH OTHER CONSENSUS ESTIMATES OF LONG-TERM GDP GROWTH.

A. The long-term growth rate in my multi-stage DCF analysis reflects growth expectations beginning ten years in the future, whereas Mr. Walters' consensus GDP projections are current five- and ten-year projections. Because there are no consensus forecasts that begin in ten years, it is reasonable to assume that real growth will revert to its long-term average over time. Because the terminal growth rate reflects expected growth in perpetuity, the term of even the longest GDP forecast considered by Mr. Walters does not reflect the expected, perpetual nature of the terminal growth assumed in the DCF model.

In his Multi-Stage DCF analysis, Mr. Walters cites to projections from the EIA, Congressional Budget Office, and other sources including the SSA, and suggests that the terminal growth rate in my Multi-Stage DCF analysis is too high.[256] Because of the inherent uncertainty in economic projections, the SSA provides three sets of projections, including intermediate, low-cost, and high-cost scenarios.[257] My long-term growth estimate falls well within the range of the "scenarios" that the SSA considers.[258]

Mr. Walters' 4.19 percent long-term sustainable growth rate also is inconsistent with market measures cited elsewhere in his testimony. For example, Mr. Walters does

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256 Direct Testimony of Christopher C. Walters at 34–35.

257 For the SSA's projections, the low-cost scenario reflects higher economic growth and interest rates.

258 Tables V.B1 and V.B2 of the 2018 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds includes "Low Cost" scenario assumptions of 2.90 percent and 3.20 percent for the GDP Price Index and CPI, respectively, and 2.70 percent for Real GDP Growth, over the period 2027 through 2092. Combined, those projections indicate nominal GDP growth of approximately 5.60 percent to 5.90 percent.

not consider the use of long-term historical data to develop his terminal growth rate, yet he relies on long-term historical data in his CAPM analyses. That is, because Mr. Walters's CAPM analysis looks to the long-term historical average Market Risk Premium, which depends (at least in part) on long-term macroeconomic growth, he also should consider the long-term GDP growth in the Multi-Stage DCF analysis. To that point, the data on which Mr. Walters relies to perform his analysis undermines his claim that a 4.19 percent estimate of long-term GDP growth is reasonable. According to Duff & Phelps (which provides the data Mr. Walters relies on to estimate the historical Market Risk Premia), the arithmetic average historical capital appreciation rate is 7.80 percent, which is substantially higher than Mr. Walters' 4.19 percent estimate of long-term GDP growth.[259]

Historically, average annual GDP growth rates as low as 4.19 percent have been infrequent. When measured over five-year periods, average annual GDP growth exceeded 4.19 percent in 71 of 85 periods. The same conclusion holds when growth is measured over ten-year periods; the average annual GDP growth rate was greater than 4.19 percent in 68 of 80 periods (*see* Charts 19 and 20 below).

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[259] Duff & Phelps, 2018 Valuation Handbook: Guide to Cost of Capital at 2-4. Even if we were to consider the geometric mean, the historical capital appreciation rate exceeds Mr. Walters' 4.19 percent estimate; Mr. Walters notes on page 31 of his testimony that the long-term geometric average growth rate of the U.S. stock market is 6.00 percent.

Chart 19: Average Annual GDP Growth Measured over Five-Year Periods[260]

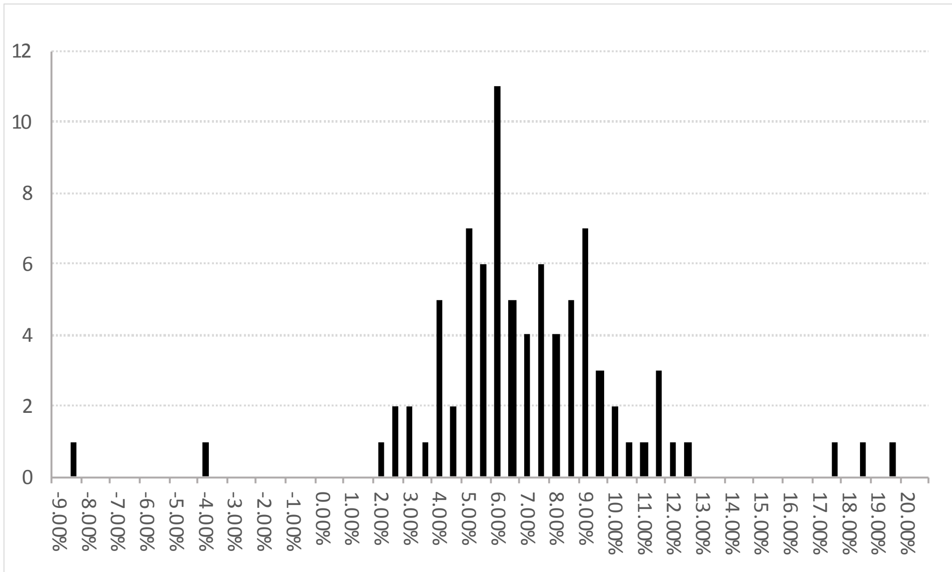
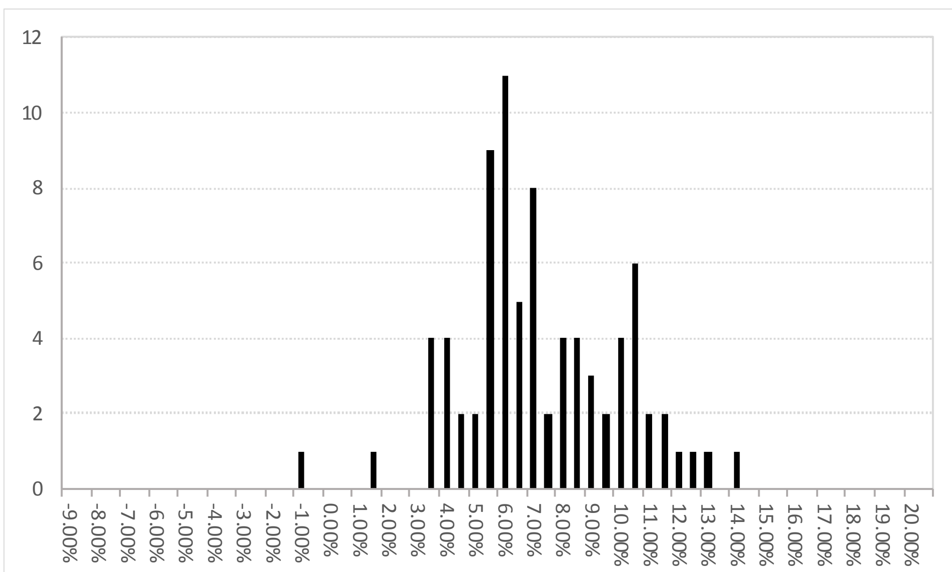


Chart 20: Average Annual GDP Growth Measured over Ten-Year Periods[261]



260 Bureau of Economic Analysis.

261 Bureau of Economic Analysis.

Q110. WHAT IS YOUR RESPONSE TO MR. WALTERS' ASSERTION THAT YOUR PAYOUT RATIO ASSUMPTION IS UNREASONABLE?

A. Mr. Walters argues there is "no basis" to expect the dividend payout ratio of the proxy group to increase or change between growth stages of the model.[262] I disagree. There are several reasons why management may adjust dividend payments in the near term, such as increases or decreases in expected capital spending. Because we cannot say those factors will remain constant forever, it is reasonable to assume over time, payout ratios will revert to their long-term average.

Several of Mr. Walters' proxy companies recently have discussed target payout ratios that are highly consistent with my 65.57 percent terminal payout ratio. For example, in late 2018 and early 2019 investor relations presentations, Alliant Energy, American Electric Power, and NorthWestern Corporation noted target payout ratios in the range of 60.00 percent to 70.00 percent.[263] Additionally, RRA expects the dividend payout ratio for electric utilities to rise from 61.70 percent in 2018 to 63.70 percent by 2021.[264] Because my projected payout ratio is consistent with both historical experience and industry expectations, it is entirely appropriate.

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262 Direct Testimony of Christopher C. Walters, at 59.

263 Alliant Energy, UBS Midstream, MLP and Utilities Conference, January 15, 2019; American Electric Power, Evercore ISI Utility CEO Retreat, January 10-11, 2019; and NorthWestern Energy, Wells Fargo Energy Symposium, New York, December 5–6, 2018.

264 Regulatory Research Associates Financial Focus *Utility Dividends: 2018 Review and Outlook*, January 24, 2019, at 8.

Q111. PLEASE RESPOND TO MR. WALTERS' CRITICISM OF YOUR TERMINAL P/E MULTI-STAGE DCF APPROACH.[265]

A. My terminal P/E approach is consistent with the fundamental assumptions underlying the Constant Growth DCF method. As discussed earlier in my response to Mr. Walters, the utility sector recently has undergone an "abnormal expansion" in P/E ratios, which have weighed on the Constant Growth DCF model's results. Mr. Walters cannot support the low Constant Growth DCF estimates that result from abnormally high P/E ratios and that weigh directly in his 9.35 percent ROE recommendation while criticizing the same assumption in my Multi-Stage DCF model.

Q112. PLEASE SUMMARIZE MR. WALTERS' CONCERNS WITH YOUR CAPM ANALYSIS.

A. Mr. Walters' concerns with my CAPM analysis lie primarily with my Market Risk Premium estimates.[266] In particular, Mr. Walters argues my 15.73 percent and 16.10 percent projected returns on the market are "inflated."[267] Mr. Walters further argues there is a "mismatch" between my calculation of the expected market return and the projected Treasury yields used in my CAPM analyses.[268]

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[265] Direct Testimony of Christopher C. Walters, at 55, 60–61.

[266] *Ibid*., at 62–63.

[267] *Ibid*., at 63.

[268] *Ibid*.

Q113. WHAT IS YOUR RESPONSE TO MR. WALTERS?

A. I disagree. The market return estimates presented in my Revised Direct Testimony, which

Mr. Walters asserts are "inflated,"[269] represent the approximately 53rd and 54th percentile of actual returns observed from 1926 to 2017. Moreover, because market returns historically have been volatile, my market return estimates are statistically indistinguishable from the long-term arithmetic average market data on which Mr. Walters relies.[270]

Mr. Walters also asserts the Market Risk Premia estimated from my projected market returns are "inflated and not reliable."[271] I therefore gathered the annual Market Risk Premia reported by Duff and Phelps and produced a histogram of the observations (recall that Mr. Walters includes historical data among the methods he uses to estimate the Market Risk Premium). The results of that analysis, which are presented in Chart 21 below, demonstrate Market Risk Premia of at least 12.99 percent (the high end of the range of the Market Risk Premium estimates in my Revised Direct Testimony) occur approximately 40.00 of the time.

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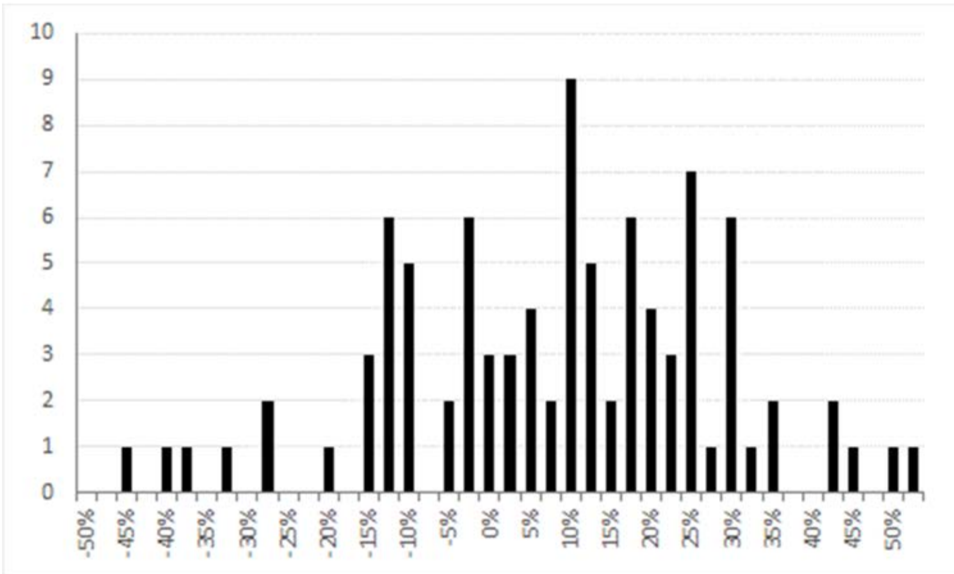
[269] *Ibid*., at 64.

[270] Source: Duff & Phelps, 2018 SBBI Yearbook Appendix A-1. Even if we were to look at the standard error, my estimates are within two standard errors of the long-term average.

[271] Direct Testimony of Christopher C. Walters, at 64.

Chart 21: Frequency Distribution of Observed Market Risk Premia, 1926 – 2017[272]



Q114. MR. WALTERS ALSO SUGGESTS YOUR EXPECTED MARKET RETURN IS INFLATED BECAUSE THE EXPECTED GROWTH RATES EXCEED THE HISTORICAL RATE OF CAPITAL APPRECIATION.[273] WHAT IS YOUR RESPONSE TO MR. WALTERS ON THAT POINT?

A. First, Mr. Walters refers to capital appreciation rates in the range of 6.00 percent to 7.80 percent.[274] To the extent either is meaningful in this context, it is the latter, which is the arithmetic mean. That simply is because the arithmetic mean reflects uncertainty, whereas the geometric mean (the 6.00 percent rate) equates a beginning value to an ending value, with no uncertainty regarding the path from the beginning to the end.

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272 ENO Exhibit RBH-31.

273 Direct Testimony of Christopher C. Walters, at 64–65.

274 *Ibid*., at 64.

Because we are focused on forward-looking estimates, which necessarily reflect uncertainty, the arithmetic average capital appreciation rate is the appropriate measure.

Second, although Mr. Walters references the long-term capital appreciation rate, he does not refer to the long-term average "income" rate (the dividend yield) of 4.00 percent, or that the current expected market dividend yield is about 2.10 percent.[275] Under the "sustainable growth" model, the higher growth rates and lower dividend yields associated with the current expected market return simply may mean that companies are retaining more of their earnings relative to the historical average. In that case, the sustainable growth method would produce growth rates higher than the historical average. Consequently, Mr. Walters' observation that current expected growth rate is higher than the historical growth rate does not demonstrate my estimates are unreasonable.

Q115. WHAT IS YOUR RESPONSE TO MR. WALTERS' CONCERN THAT THERE IS A "MISMATCH" BETWEEN THE EXPECTED MARKET RETURN, AND THE PROJECTED TREASURY YIELDS IN YOUR CAPM ANALYSIS?

A. Mr. Walters argues that there is an "error" in my calculations because the risk-free rate used to calculate the market risk premium is not the same risk-free rate used in my CAPM estimates based on the near-term projected Treasury yields.[276] That is, Mr.

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275 Source: Bloomberg Professional, Value Line. *See* ENO Exhibit RBH-16.

276 Direct Testimony of Christopher C. Walters, at 65.

Walters appears to argue that the risk-free rate used to calculate the Market Risk Premium should be the same as the risk-free rate term in the CAPM.[277]

Despite that concern, Mr. Walters' CAPM analysis relies on a method of calculation that is comparable to mine. As Mr. Walters explains, his long-term historical Market Risk Premium estimate (6.10 percent) is the difference between the average market return (approximately 12.10 percent) and the total return of long-term Government bonds (approximately 6.00 percent).[278] But his CAPM estimate, which is presented in his Schedule CCW-16, assumes a risk-free rate component of 3.60 percent, not the 6.00 percent used in his Market Risk Premium calculation. That is, Mr. Walters' CAPM estimate includes the same type of "mismatch" he claims is an "error" on my part. Had he chosen to use the 6.00 percent risk-free rate that underlies the 12.10 percent market return, Mr. Walters' CAPM estimate would have been 240 basis points higher.[279]

Q116. AT PAGE 81 OF HIS DIRECT TESTIMONY, MR. WALTERS ARGUES THAT YOUR CONSIDERATION OF PROJECTED TREASURY YIELDS IS "UNREASONABLE" BECAUSE YOU DO NOT CONSIDER "THE HIGHLY LIKELY OUTCOME THAT CURRENT OBSERVABLE INTEREST RATES WILL PREVAIL DURING THE PERIOD IN WHICH RATES DETERMINED IN THIS PROCEEDING WILL BE IN EFFECT." IS MR. WALTERS CORRECT?

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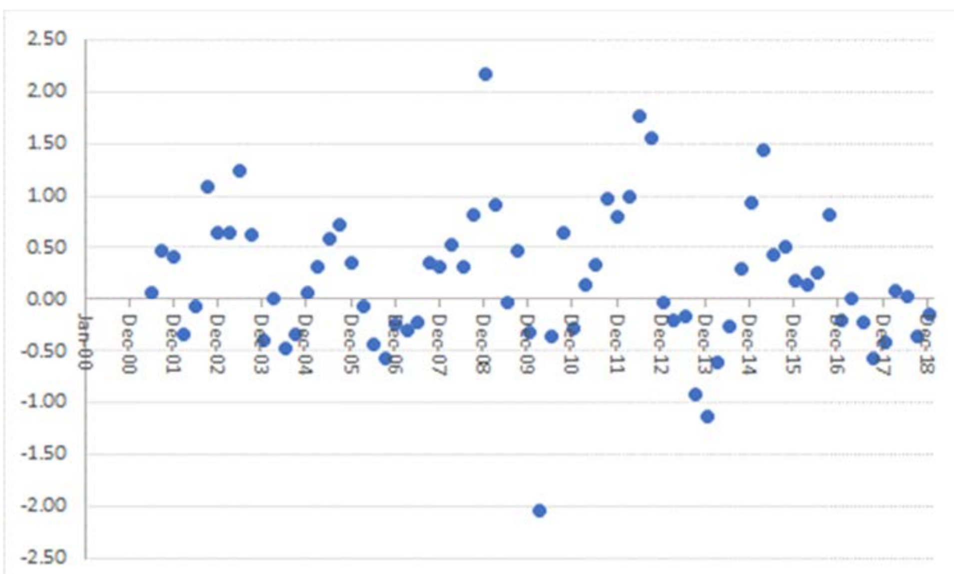
277 That is, Mr. Walters argues that in my analyses the term "r_f" should be the same number in the CAPM equation: $k_e = r_f + \beta(r_m - r_f)$.

278 Direct Testimony of Christopher C. Walters, at 45.

279 2.40% = 6.00% - 3.60%.

A. No, he is not. Mr. Walters argues the "accuracy of forecasted interest rates is problematic at best."[280] He states that over the last several years, "current observable interest rates are just as likely to accurately predict future interest rates as are economists' projections."[281] Although Mr. Walters suggests current yields are a "more accurate predictor" of future yields, he has not indicated what that level of accuracy might be, or how it figures in his conclusion. As Chart 22 (below) demonstrates, using the same quarterly convention applied in Schedule CCW-18 (that is, comparing forecasts five quarters in the future to the actual yields observed in those forecast quarters) shows actual yields were not accurate predictors of future yields. In fact, the forecast error generally was positive through 2015, indicating that observed yields over-predicted actual yields.

Chart 22: Forecast Error of Spot 30-Year Treasury Yields[282]



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280 Direct Testimony of Christopher C. Walters, at 81.

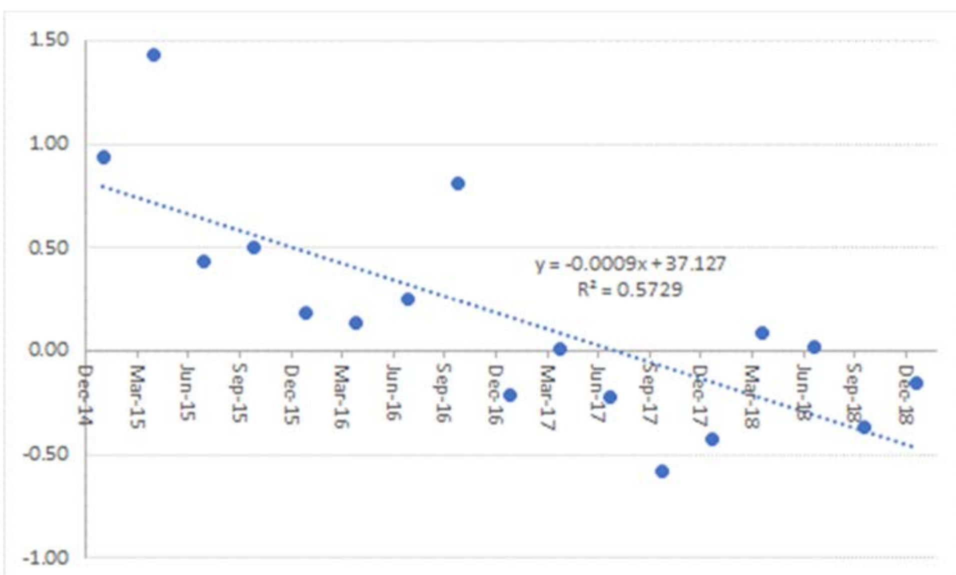
281 *Ibid.*, at 82.

282 Source: Bloomberg Professional.

Those results make intuitive sense. During much of the review period (2000 through 2018), interest rates were undergoing a secular decline; with the 2008/2009 recession, interest rates became the subject of Federal monetary policies specifically designed to keep them low. Because yields fell during that time, prior quarters were likely to over-estimate future quarters.

Although interest yields steadily declined between 2000 and 2015, as noted in my Revised Direct Testimony, in December 2015 the Federal Reserved began its process of monetary policy normalization.[283] The effect of that change in policy and improving economic conditions is shown in Chart 23 (below), which limits the review period to the seventeen quarters from December 2014 through December 2018. As interest rates have begun to increase, spot Treasury yields have begun to under-project future yields.

Chart 23: Forecast Error of Spot 30-Year Treasury Yields Since December 2014[284]



[283] Revised Direct Testimony of Robert B. Hevert, at 67.

[284] Source: Bloomberg Professional.

To the extent interest rates continue to increase, Mr. Walters' suggested approach of using spot yields as a measure of forecast yields will systematically under-estimate Treasury yields, and therefore systematically bias downward his model results.

Q117. PLEASE SUMMARIZE MR. WALTERS' CRITICISMS OF YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. Mr. Walters' concern with my Bond Yield Plus Risk Premium analysis is my "contention" of a "simplistic inverse relationship" between the Equity Risk Premium and interest rates, which he suggests is not supported by academic research.[285] He argues that the relevant factor explaining changes in the Equity Risk Premiums is the change to equity risk relative to debt risk, not changes in interest rates alone. Additionally, Mr. Walters asserts that the relationship between the Equity Risk Premium and interest rates is weaker in "the 2010 through the April 2018 post-recession period".[286]

Q118. WHAT IS YOUR RESPONSE TO MR. WALTERS' POSITION ON THOSE POINTS?

A. Regarding the inverse relationship between the Equity Risk Premium and interest rates, several academic studies support my findings.[287] Regarding his analysis using my data

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[285] Direct Testimony of Christopher C. Walters, at 67.

[286] *Ibid*., at 70. I note that while Mr. Walters discusses the period through April 2018, his Figure 4 includes data through June 2018.

[287] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

over the 2010 to June 2018 period, Mr. Walters argues that because the "R-squared" is only 45.00 percent, it suggests there is not a "strong relationship" between the two variables.[288] I disagree. The salient question is whether the relationship is statistically significant. As

shown in Table 7, the T-statistics show that both the intercept and the 30-year Treasury yield (the independent variable) are highly significant.[289]

Table 7: Regression Coefficients for Bond Yield Plus Risk Premium Analysis, January 2010 - June 2018

	Coefficient	T-Statistic	P-Value	Standard Error
Intercept	-0.0103	-2.235	0.026	0.005
30-Year Treasury Yield	-0.0222	-16.367	0.000	0.001

Q119. DID YOU PERFORM ANY ADDITIONAL ANALYSES TO ADDRESS MR. WALTERS' CONCERN REGARDING THE EFFECT OF EXPECTED MARKET VOLATILITY AND INTEREST RATE ENVIRONMENTS ON YOUR RESULTS?

A. Yes, I did. Although for the reasons discussed above I continue to believe the Risk Premium is properly specified, I performed an additional analysis to specifically include the effect of equity market volatility and credit spreads (*see* ENO Exhibit RBH-32). As with my original Bond Yield Plus Risk Premium analysis, I defined the Risk Premium as the dependent variable and the prevailing 30-year Treasury yield as an independent variable. I then included two additional explanatory variables: (1) the VIX (the Chicago

[288] Direct Testimony of Christopher C. Walters, at 69.

[289] As noted earlier, a T-statistic higher than 2.00 (absolute value) indicates a statistically significant relationship at the 95.00 percent confidence level.

Board Options Exchange's one-month volatility index, which is a common measure of volatility); and (2) the credit spread between the 30-year Treasury yield and the Moody's Baa Utility Index (as a measure of incremental risk).[290] In both instances, the statistically significant inverse relationship between Treasury yields and the Risk Premium remains, and the resulting ROE estimates are generally consistent with those of my original and updated Bond Yield Plus Risk Premium analysis.[291]

Lastly, applying Mr. Walters' projected 3.60 percent 30-year Treasury yield to the alternative Bond Yield Plus Risk Premium Analysis discussed above produces an ROE estimate of 9.96 percent relative to Mr. Walters' 9.35 percent recommendation (*see* ENO Exhibit RBH-32).[292]

Q120. WHAT IS MR. WALTERS' CONCERN WITH YOUR EVALUATION OF THE COMPANY'S CAPITAL EXPENDITURE PLAN AS IT RELATES TO THE COST OF EQUITY?

A. Mr. Walters argues ENO's capital expenditure forecasts are not "out of line" with the utility industry."[293] He point to his Schedule CCW-1,[294] noting that "the industry as a whole is expected to require access to the external capital markets due to producing less

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290 Mr. Walters notes on page 21 of his testimony that his proxy group has an average Moody's credit rating of Baa1. *See* ENO Exhibit RBH-32.

291 *See* ENO Exhibit RBH-32, ENO Exhibit RBH-19, and ENO Exhibit RBH-7.

292 Mr. Walters uses a 3.60 percent projected Treasury yield in his risk premium analysis. *See* Direct Testimony of Christopher C. Walters, at 41.

293 Direct Testimony of Christopher C. Walters, at 75.

294 Although Mr. Walters points to Page 6 of Schedule CCW-1, Page 7 of provides his Cash Flow/Capital Spending analysis.

cash flow per share than capital spending per share."[295] However, nowhere does his analysis compare ENO to "the utility industry", or demonstrate it is in line with the industry. As noted in my Revised Direct Testimony, the Cost of Equity is necessarily a comparative exercise; therefore, any analysis must compare the subject company to a comparable peer group,[296] as I have done in ENO Exhibit RBH-8. As I demonstrated in ENO Exhibit RBH-8, the Company's planned capital expenditures (as a share of net plant) are well above the proxy group.

Q121. PLEASE SUMMARIZE MR. WALTERS' TESTIMONY AS IT RELATES TO FLOTATION COSTS.

A. Mr. Walters argues that the flotation cost adjustment is unreasonable because it is "not based on the recovery of prudent and verifiable actual flotation costs incurred by ENO."[297]

Q122. WHAT IS YOUR RESPONSE TO MR. WALTERS REGARDING THE NEED TO RECOVER FLOTATION COSTS?

A. As explained in my Revised Direct Testimony, flotation costs are not reflected on the income statement as they are not current expenses. Rather they are part of the invested costs of the utility and are reflected on the balance sheet under "paid in capital."[298]

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295 Direct Testimony of Christopher C. Walters, at 75.

296 Revised Direct Testimony of Robert B. Hevert, at 7.

297 Direct Testimony of Christopher C. Walters, at 78.

298 Revised Direct Testimony of Robert B. Hevert, at 56.

Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. Because flotation costs permanently reduce the equity portion of the balance sheet, an adjustment must be made to the ROE to ensure that the authorized return enables investors to realize their required return.

I have provided an illustrative example of the effect of flotation costs on the ROE in ENO Exhibit RBH-33.[299] As shown in that exhibit, due to the effect of flotation costs, an authorized return of 10.87 percent would be required to realize an ROE of 10.75 percent (*i.e.*, a 12-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.63 percent (*i.e.*, below the required return).[300]

V. RESPONSE TO CRESCENT CITY POWER USERS' GROUP WITNESS BAUDINO

Q123. PLEASE SUMMARIZE MR. BAUDINO'S ROE ANALYSES AND ROE RECOMMENDATION IN THIS PROCEEDING.

A. Mr. Baudino recommends an ROE of 9.35 percent, which is based on the results of his Constant Growth DCF analyses applied to the proxy group of 22 companies used in my Revised Direct Testimony.[301] Mr. Baudino also performs two CAPM analyses, which he uses in support of his DCF results and recommended ROE.[302]

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[299] This example is based on an analysis performed by Dr. Roger Morin. *See* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 330–332.

[300] ENO Exhibit RBH-33 is provided for illustrative purposes only. I have not relied on the results of the analysis in determining my recommended ROE or range.

[301] Direct Testimony of Richard A. Baudino, at 3, 15.

[302] *Ibid*.

Q124. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH MR. BAUDINO'S ROE ANALYSES?

A. The principal areas in which I disagree with Mr. Baudino include: (1) his reliance on the Constant Growth DCF model to determine the Company's Cost of Equity; (2) the growth rates applied in the Constant Growth DCF model; (3) the application of the Multi-Stage DCF model; (4) the risk-free rate and Market Risk Premium used in the CAPM; (5) whether the Bond Yield Plus Risk Premium analysis provides reasonable estimates of the Company's Cost of Equity; (6) our respective assessments of the Company's level of business and financial risk; and (7) interpretation of current capital market conditions and their effect on ROE.

Q125. AS A PRELIMINARY MATTER, MR. BAUDINO NOTES YOUR ROE RECOMMENDATION IGNORES YOUR DCF RESULTS AND SUGGESTS YOUR ROE RANGE SHOULD BE REJECTED BY THE CITY COUNCIL AS UNSUPPORTED BY YOUR ANALYSES.[303] WHAT IS YOUR RESPONSE?

A. As noted in my Revised Direct Testimony and throughout my Rebuttal Testimony, all models are subject to limiting assumptions and no single model is more reliable than all others under all market conditions. As also noted in my Revised Direct Testimony, it is my view that the Constant Growth DCF model is subject to several assumptions that likely are not consistent with current market conditions, and therefore should be given

[303] *Ibid.*, at 33–39.

less weight in the current capital market. To that point (and as noted earlier), authorized returns consistently have exceeded Constant Growth DCF estimates.[304] Further, as discussed in Section II above, other regulatory commissions and the FERC have found it appropriate to place less weight on the DCF model results. As to Mr. Baudino's argument that I reject the results of two of my four methods, he rejects two out of his three approaches, relying exclusively on his Constant Growth DCF model results. Lastly, although Mr. Baudino argues that relying on the high DCF results is inappropriate, his 9.35 percent recommendation is based on his high DCF result.[305]

A. Application of the Constant Growth DCF Model

Q126. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONSTANT GROWTH DCF ANALYSIS AND RESULTS.

A. Mr. Baudino calculates an average dividend yield of 3.26 percent by dividing each proxy company's annualized dividend by its monthly stock price for the six-month period ending December 2018.[306] Mr. Baudino notes that the average dividend yield for the proxy group ranged from 3.23 percent to 3.30 percent during the six-month period.[307] For the expected growth rate, Mr. Baudino relies on Earnings Per Share growth rate projections from Value Line, Zacks, and First Call, as well as dividend per share ("DPS")

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304 *See* Chart 1.

305 Direct Testimony of Richard A. Baudino, at 30.

306 *Ibid.*, at 20.

307 *Ibid*.

growth rate projections from Value Line.[308] Mr. Baudino then calculates DCF results based on the mean and median growth rate of the four sources noted above, producing eight ROE estimates, ranging from 8.52 percent to 9.36 percent.[309]

Mr. Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced using median growth rates as "Method 2". The mean DCF results of his Methods 1 and 2 were 9.05 percent and 8.97 percent, respectively.[310]

Q127. DO YOU AGREE WITH MR. BAUDINO THAT DIVIDEND GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?

A. No, I do not. As discussed in my Revised Direct Testimony, academic literature supports the use of earnings growth rates in the DCF model.[311] Earnings growth is the fundamental driver of the ability to pay dividends. As noted in my Revised Direct Testimony, to reduce growth to a single measure we assume a fixed payout ratio, and a constant growth rate for earnings per share ("EPS"), DPS, and book value per share ("BVPS").[312] ENO Exhibit RBH-34 illustrates that under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock prices all grow at the same, constant rate in perpetuity. Because earnings are the fundamental driver of

308 *Ibid.* at 22.

309 *Ibid.* at 23.

310 *Ibid.*

311 *See* Revised Direct Testimony of Robert B. Hevert, at 19–21.

312 *Ibid.*, at 18–19.

dividends, and knowing investors tend to value common equity on the basis of Price/Earnings ratios, the Cost of Equity is a function of the expected growth in earnings, not dividends. That is, earnings growth enables both dividend and book value growth. Book value can increase over time only through the addition of retained earnings, or with the issuance of new equity. Both of those factors are derivative of earnings: retained earnings increases with the amount of earnings not distributed as dividends; and the price at which new equity is issued is a function of the EPS and the then-current P/E ratio.

In addition, Value Line is the only service on which Mr. Baudino relies that provides DPS growth projections. To the extent that the earnings projections services such as Zacks and First Call represent consensus estimates, the results are less likely to be skewed in one direction or another as a result of an individual analyst.

B. DCF Model Assumptions

Q128. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONCERNS WITH YOUR ARGUMENTS REGARDING THE ASSUMPTIONS OF THE DCF MODEL.

A. Mr. Baudino argues: (1) the industry's current payout ratio's departure from the long-term average is not a valid concern; and (2) the industry's current P/E ratio's departure from its long-term average is not a valid concern.[313]

[313] Direct Testimony of Richard A. Baudino, at 37.

Q129. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S CONCERN WITH YOUR ASSUMPTION REGARDING PAYOUT RATIOS?

A. As discussed in my responses to Mr. Walters (above), it is reasonable to assume, as Mr. Baudino recognizes,[314] that near-term payout ratios will revert to the long-term industry average over the horizon of the DCF analysis and that assumption is consistent with the stated payout ratio targets of several electric utility companies.[315] In that regard, it is the Constant Growth DCF model relied on by Mr. Baudino (which assumes that payout ratios will remain unchanged in perpetuity) that is inconsistent with investor expectations.

Q130. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S CONCERN WITH YOUR ASSUMPTION REGARDING P/E RATIOS?

A. Mr. Baudino observes that current stock prices reflect investors' required ROE.[316] However, as explained in my response to the Advisors' ROE Witnesses, the DCF model will not produce accurate estimates of the market-required ROE if the market price diverges from intrinsic value as defined by the present value formula.

The equity valuation levels recently observed more likely arose from the "reach for yield" that sometimes occurs during periods of low Treasury yields. During those periods, some investors would turn to dividend-paying sectors, such as utilities, as an

[314] *Ibid*.

[315] As discussed in my response to the Mr. Walters, Alliant Energy, American Electric Power, and NorthWestern Corporation noted target payout ratios in the range of 60.00 percent to 70.00 percent.

[316] Direct Testimony of Richard A. Baudino, at 37.

alternative source of income (that is, for the dividend yield).[317] Then, when interest rates increased, investors rotated out of the utility sector, causing prices to fall. Because the Constant Growth DCF model assumes a constant P/E ratio in perpetuity, in periods of elevated P/E ratios, the Constant Growth DCF model understates the required return. As discussed in my Revised Direct Testimony, interest rates are expected to increase.[318] Consequently, it is unreasonable to place significant weight on the Constant Growth DCF model's results when the assumptions underlying that model are plainly inconsistent with market expectations.

Q131. HAVE THERE BEEN RECENT PERIODS WHEN UTILITY VALUATION LEVELS WERE HIGH RELATIVE TO BOTH THEIR LONG-TERM AVERAGE AND THE MARKET?

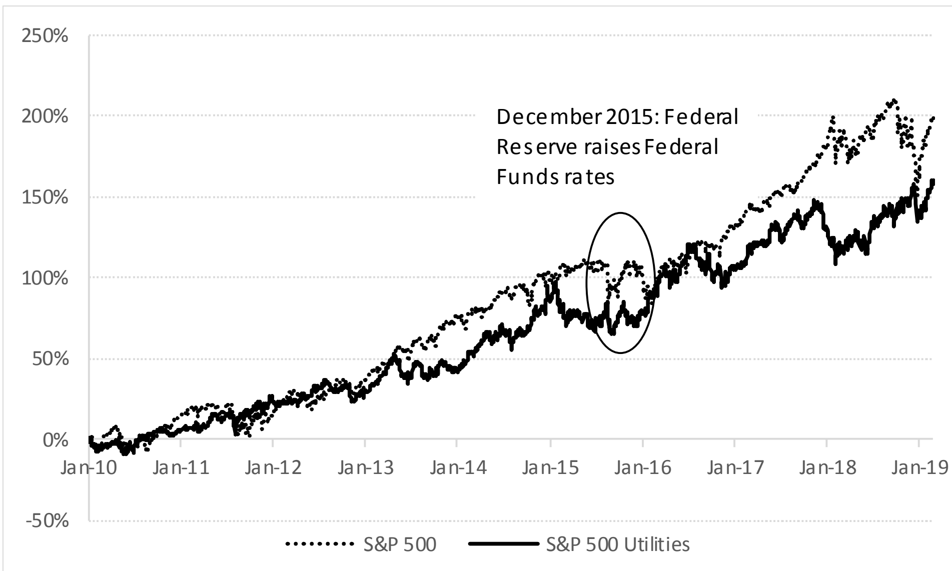
A. Yes. For example, between July and December 2016, the S&P Electric Utility Index lost approximately 9.00 percent of its value. At the same time, the S&P 500 increased by approximately 7.00 percent, indicating that the utility sector under-performed the market by about 16.00 percent. Also during that time, the 30-year Treasury yield increased by as much as approximately 95 basis points (an increase of approximately 44.00 percent). More recently, between January and March 2018, the S&P Electric Utility Index lost approximately 7.00 percent of its value while the S&P 500 increased by approximately

[317] The relationship between utility prices and utility dividend yields is given in Equation [2], page 17 of my Revised Direct Testimony.

[318] *See* Revised Direct Testimony of Robert B. Hevert, at 73. For example, consensus estimates project the 30-year Treasury yield to increase to 3.40 percent by the second quarter of 2020 and to 3.90 percent by 2022. *See*, Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2; Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.

2.00 percent, an under-performance of about 9.00 percent as the 30-year Treasury yield increased by nearly 40 basis points. The point simply is that as interest rates increased, utility valuations fell. As shown in Chart 24, below, since the Federal Reserve began raising interest rates in 2015, utilities (as measured by the S&P 500 Utilities Index) have underperformed the broad market by a substantial margin.

Chart 24: S&P 500 Utilities vs S&P 500 Returns[319]



C. Multi-Stage DCF Analysis

Q132. DO YOU AGREE WITH MR. BAUDINO'S ASSERTION THAT YOUR LONG-TERM GROWTH RATE ESTIMATE IS OVERSTATED?[320]

A. No. For the reasons explained in my response to the Advisors' ROE Witnesses and Mr. Walters, my long-term growth rate is reasonable and consistent with historical growth. The 5.45 percent long-term growth rate used in my Multi-Stage DCF model is within the

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319 Source: S&P Global Market Intelligence.

320 Direct Testimony of Richard A. Baudino, at 40–41.

bounds of the long-term growth estimates Mr. Baudino uses in his Constant Growth DCF analysis (mean rates ranging from 5.36 percent to 6.00 percent, and median rates ranging from 5.17 percent to 6.00 percent).[321]

D. Capital Asset Pricing Model

Q133. PLEASE SUMMARIZE MR. BAUDINO'S CAPM ANALYSES.

A. Mr. Baudino performs two sets of CAPM analyses. His first set calculates two Market Risk Premium measures, which rely on the forecasted total market return as determined using Value Line projections, and six-month averages of five and 30-year Treasury security yields (*i.e.*, 2.85 percent and 3.17 percent, respectively).[322] Mr. Baudino assumes a total growth rate for the market of 10.25 percent, using the average of the book value and earnings growth forecasts (8.50 percent and 12.00 percent, respectively) for all companies covered by Value Line. Mr. Baudino combines that average growth rate with Value Line's average expected dividend yield of 1.19 percent for the same group of companies, which results in an estimated market return of 11.50 percent. Mr. Baudino then averages that estimate with Value Line's projected annual total return of 16.00 percent to arrive at his final expected market return of 13.75 percent.[323]

Mr. Baudino's two Market Risk Premium measures represent the difference between (1) his calculated expected market total return, and (2) the average yield over the past six months on five- and 30-year Treasury securities. Mr. Baudino arrives at his

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321 Exhibit__(RAB-3).

322 Exhibit__(RAB-4).

323 Direct Testimony of Richard A. Baudino, at 26. Exhibit__(RAB-4).

CAPM results using the average Value Line Beta coefficient of 0.60 for his proxy companies.[324]

Mr. Baudino's second set of CAPM analyses calculate the geometric and arithmetic mean long-term annual returns on stocks, and long-term annual income returns on long-term government bonds, resulting in two historical measures of the Market Risk Premium.[325] Mr. Baudino uses those two Market Risk Premium measures in combination with the current five and 30-year Treasury bond yield and the average Value Line Beta coefficient to calculate two additional CAPM results. Lastly, Mr. Baudino considers an adjusted historical Market Risk Premium calculated by Dr. Roger Ibbotson and Dr. Peng Chen, and reported by Duff & Phelps.[326]

Although Mr. Baudino advises the City Council to consider only his DCF results in establishing the Company's ROE, he does report CAPM results ranging from 9.34 percent to 9.47 percent for his forward-looking return analysis and 6.26 percent to 7.39 percent for his historical returns analysis.[327]

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324 *Ibid.*, at 29. Exhibit__(RAB-4).

325 *Ibid.*, at 27-28. Exhibit__(RAB-4).

326 *Ibid.*, at 28. Exhibit__(RAB-4).

327 Direct Testimony of Richard A. Baudino, at 29.

Q134. DO YOU AGREE WITH MR. BAUDINO'S APPLICATION OF THE CAPM AND HIS INTERPRETATION OF ITS RESULTS?

A. No. There are two areas in which I disagree with Mr. Baudino: (1) the term of the Treasury security used as the risk-free rate component of the model; and (2) the calculation of the Market Risk Premium.

Q135. TURNING FIRST TO THE RISK-FREE RATE COMPONENT, WHY DO YOU DISAGREE WITH MR. BAUDINO'S USE OF FIVE-YEAR TREASURY SECURITY AS THE MEASURE OF THE RISK-FREE RATE?

A. As a preliminary matter, I do not disagree with Mr. Baudino's use of the 30-year Treasury bond as the risk-free rate. As discussed in my response to Mr. Proctor, the tenor of the risk-free rate used in the CAPM should match the life (or duration) of the underlying investment. Like Mr. Watson's proxy group (*see* ENO Exhibit RBH-22), the average Equity Duration of the companies in Mr. Baudino's proxy group is 32.36 years. Given that relatively long Equity Duration, and knowing that utility assets are comparatively long-lived, I continue to believe that it is appropriate to use the long-term (*i.e.*, 30-year) Treasury yield as the measure of the risk-free rate.

Q136. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S SUGGESTION THAT "THE RISK-FREE RATE SHOULD HAVE NO INTEREST RATE RISK"?[328]

A. I disagree. If Mr. Baudino is concerned with interest rate risk *per se*, he should focus exclusively on short-term Treasury Bills as the risk-free security, even though they may be less "stable" than longer-dated Treasury bonds.[329] Adopting such short-term securities, of course, would further decrease his already-low CAPM estimates. In any case, the perpetual nature of equity argues for the longest-term Treasury security, the 30-year Treasury Bond, to measure the risk-free rate.

Q137. WHAT CONCERNS DO YOU HAVE WITH MR. BAUDINO'S *EX-ANTE* MARKET RISK PREMIUM CALCULATIONS?

A. Mr. Baudino calculates the expected market return using an average of earnings growth projections (12.00 percent) and book value growth projections (8.50 percent). As noted above, academic research indicates investors rely on estimates of earnings growth in arriving at their investment decisions. In that regard, Mr. Baudino did not include book value growth projections in his proxy group DCF analysis; he has not explained why it is reasonable to include those growth rates in his Market Risk Premium analysis but exclude them from his proxy company DCF analyses. Excluding book value growth estimates from Mr. Baudino's market return calculation would increase his Market Risk Premium estimate by approximately 84 basis points on average.

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[328] *Ibid.*, at 43.

[329] *Ibid.*

Q138. DO YOU AGREE WITH MR. BAUDINO'S USE OF HISTORICAL ESTIMATES OF THE MARKET RISK PREMIUM?

A. No, I do not. For the reasons discussed in my response to the Advisors' ROE Witnesses and Mr. Walters, the Market Risk Premium is meant to be a forward-looking parameter. A Market Risk Premium calculated using historical market returns does not necessarily reflect investors' expectations or, for that matter, the relationship between market risk and returns. The relevant analytical issue in applying the CAPM is to ensure that all three components of the model (*i.e.*, the risk-free rate, Beta, and the Market Risk Premium) are consistent with market conditions and investor expectations. Therefore, *ex-ante* CAPM analyses are the more appropriate method to estimate ENO's Cost of Equity. Lastly, if Mr. Baudino chooses to rely on historical data, he should consider the inverse relationship between the Market Risk Premium and interest rates.

Q139. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S COMMENTS REGARDING YOUR *EX-ANTE* CAPM ANALYSES.

A. Mr. Baudino disagrees with my *ex-ante* Market Risk Premium, arguing that the underlying growth rates "are by no means long-run sustainable growth rates."[330] Mr. Baudino further suggests the forecasted Treasury bond yields applied in my CAPM analyses are "speculative at best and may never come to pass."[331]

[330] *Ibid.*, at 44.

[331] *Ibid.*, at 42.

Q140. DO YOU AGREE WITH MR. BAUDINO'S CONCERNS IN THAT REGARD?

A. No, I do not. As discussed in my response to Mr. Walters, my estimates of the Market Risk Premium are consistent with historical experience. [332] Regarding the use of projected interest rates, it is important to remember that, as Mr. Baudino states, the "[r]eturn on equity analysis is a forward-looking process."[333] In that regard, I have considered forward-looking estimates of the risk-free rate. Because my analyses are predicated on market expectations, the expected increase in Treasury yields (as reflected in consensus projections) is a measurable and relevant data point.

E. Bond Yield Plus Risk Premium Approach

Q141. WHAT CONCERNS DOES MR. BAUDINO EXPRESS REGARDING YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Mr. Baudino suggests the Bond Yield Plus Risk Premium method is "imprecise and can only provide very general guidance," and notes that "[r]isk premiums can change substantially over time."[334] In the end, Mr. Baudino likens the approach to a "blunt instrument".[335] Regarding its application, Mr. Baudino disagrees with the use of projected Treasury yields in calculating the range of Risk Premium-based results.

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332 *See* Chart 21 above in my response to Mr. Walters and ENO Exhibit RBH-31.

333 Direct Testimony of Richard A. Baudino, at 21.

334 *Ibid.*, at 45.

335 *Ibid.*

Q142. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S OBSERVATIONS?

A. Turning first to Mr. Baudino's point that the Risk Premium can change over time, I agree. As noted in my Revised Direct Testimony, there is a statistically significant negative relationship between long-term Treasury yields and the Equity Risk Premium.[336] Given Mr. Baudino's observation that interest rates have declined since 2008, the Bond Yield Plus Risk Premium analysis provides an empirically and theoretically sound method of quantifying the relationship between the Cost of Equity and interest rates. That is, it provides a method to quantify the change Mr. Baudino has observed.

As to Mr. Baudino's notion that the approach is a "blunt instrument," I disagree. As shown in Chart 1 in my Revised Direct Testimony, the R-squared of the Bond Yield Plus Risk Premium regression analysis is approximately 0.74, indicating a rather high degree of explanatory value. More importantly (and as discussed in my response to Mr. Walters), the relationship is highly statistically significant. Consequently, and as explained in my response to the Advisors' ROE Witnesses, the Bond Yield Plus Risk Premium approach provides empirically and theoretically sound results that can be used, at a minimum, to assess the wide range of ROE results produced by Mr. Baudino's analyses in general, and his 9.35 percent recommendation in particular.

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[336] Revised Direct Testimony of Robert B. Hevert, at 35, 37.

Q143. DO YOU AGREE WITH MR. BAUDINO'S CLAIM THAT INCLUDING RATE CASE RESULTS SINCE 1980 IS "AN IRRELEVANT EXERCISE"?[337]

A. No, I do not. Simply, the model focuses on the relationship between interest rates and the Equity Risk Premium; it does not view the two in isolation. There is no evidence that excluding data from my analysis would improve the model's ability to estimate expected returns.

F. Business Risks

Q144. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S POSITION REGARDING THE COMPANY'S BUSINESS RISKS.

A. Mr. Baudino argues that the business risks discussed in my Revised Direct Testimony are covered in ENO's credit rating agency reports and that because S&P's credit rating assigned to the Company is "consistent with the proxy group", he does not believe an additional risk premium for the Company is appropriate.[338]

Q145. WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. As with the other intervening witnesses, Mr. Baudino's assertion that ENO's credit rating is "consistent with" the proxy group fails to consider the Company's Moody's Ba1 rating. None of the other proxy group companies have a below investment grade credit rating. From that perspective alone, I disagree that the Company's risk (from the perspective of the rating agencies) is similar to the proxy group. That point aside, as

337 Direct Testimony of Richard A. Baudino, at 38.

338 *Ibid.*, at 47.

explained in my response to the Advisors' ROE Witnesses, credit ratings speak to overall creditworthiness from the perspective of debtholders, not equity holders. We therefore cannot draw firm inferences regarding differences in the Cost of Equity from differences in credit rating notches.

Q146. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S ARGUMENT THAT THE SMALL SIZE ANALYSIS DOES NOT APPLY TO ENO BECAUSE THE ANALYSIS CONTAINS UNREGULATED COMPANIES?

A. As noted in my Revised Direct Testimony, although studies of the size effect often include unregulated industries, analysts have also noted utilities face risks associated with small size as well (such as concentrated customer base, limited financial resources, and lack of geographic diversity).[339] In addition to the studies cited in my Revised Direct Testimony, Dr. Morin discusses the small size effect Ibbotson Associates found for utility companies in particular:

> To illustrate, the Ibbotson data suggests that under SIC Code 49, *Electric, Gas & Sanitary Services*, the average return for that group over an almost 80-year period was 14.03% for the small-cap company group and 10.86% for the large-cap group, more than a 300 basis point difference. This is true for all industry groups.[340]

Regardless, as discussed in my response to the Advisors' ROE Witnesses, I have not made a specific size adjustment to my recommended ROE. Rather, I take into consideration the additional risk implied by ENO's small size relative to the proxy group

[339] *See* Revised Direct Testimony of Robert B. Hevert, at 52.

[340] *See* Morin, Roger A., New Regulatory Finance, Public Utilities Report, Inc., 2006, at 182.

when determining where within the range of ROE model results the appropriate ROE should be.

Q147. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S ARGUMENT THAT THE COMPANY'S FORMULA RATE PLAN REDUCES ENO'S RISK?[341]

A. For the reasons explained in my response to Mr. Proctor, I disagree. As Mr. Baudino suggests, rate structures such as the Formula Rate Plan are more likely to be credit supportive, rather than credit enhancing.[342]

Q148. MR. BAUDINO SUGGESTS FLOTATION COSTS "LIKELY" ARE ACCOUNTED FOR IN CURRENT STOCK PRICES.[343] IS HE CORRECT?

A. No, he is not. As explained in my Revised Direct Testimony, the models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model).[344]

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341 Direct Testimony of Richard A. Baudino, at 47–48.

342 *Ibid*., at 48.

343 *Ibid*.

344 Revised Direct Testimony of Robert B. Hevert, at 57. *See also* ENO Exhibit RBH-33 for an illustrative example.

G. Capital Market Environment

Q149. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S DISCUSSION OF CAPITAL MARKETS.

A. Mr. Baudino acknowledges that interest rates increased in the second half of 2016 and will likely continue raising rates into 2019.[345] However, Mr. Baudino "firmly believe[s] that it would not be advisable for utility regulators to raise ROEs in anticipation of higher forecasted interest rates that may or may not occur."[346] As discussed in my Revised Direct Testimony, and earlier in my response to Mr. Baudino, investors expect interest rates to rise in the short- and medium-term. Because we are focused on understanding required returns from investors' perspectives, we should reflect data that is important to them. Mr. Baudino has provided no evidence that projected interest rates are of no consequence to investors.

Q150. MR. BAUDINO ALSO ARGUES THAT "EXPECTATIONS OF HIGHER FUTURE INTEREST RATES, IF ANY, ARE ALREADY LIKELY EMBODIED IN CURRENT SECURITIES PRICES, WHICH INCLUDE DEBT SECURITIES AND STOCK PRICES."[347] DO YOU AGREE WITH MR. BAUDINO'S ARGUMENT?

A. Mr. Baudino makes that argument in the context of "market efficiency", suggesting that if markets are efficient, expectations regarding the direction and level of interest rates already are embedded in stock prices and Treasury yields. Mr. Baudino points to Dr.

[345] Direct Testimony of Richard A. Baudino, at 9–11.

[346] *Ibid.*, at 10.

[347] *Ibid.*, at 9.

Morin's 2006 reference to the forecast accuracy of naïve extrapolations and "no-change" methods of projecting interest rates in support of his position that there is no need to consider projected interest rates in setting the current ROE.[348] I have several responses to Mr. Baudino on those points.

Regarding the suggestion that the "no-change" method of projecting interest rates is appropriate in the current market, I do not believe that to be the case. As discussed in my response to Mr. Walters, the Federal Reserve's Quantitative Easing program, which was initiated after 2006 (that is, after Dr. Morin's book was published), was designed to put downward pressure on long-term interest rates. Consequently, the observed Treasury yield in a given month likely would over-forecast the observed Treasury yield twelve months in the future.[349] Conversely, when the Federal Reserve completed its Quantitative Easing program, it would be reasonable to assume the observed Treasury yield would under-forecast the yield twelve months in the future (as yields increase). That would be the case even though the Federal Reserve has not yet unwound the $4 trillion of assets it acquired during Quantitative Easing. As Chart 23 above demonstrates, that is clearly the case.

Mr. Baudino's data support that position. As shown in Table 8, from February 2007 through the end of Quantitative Easing (October 2015),[350] the 30-year Treasury yield over-forecast the twelve-month forward yield 71.00 percent of the time. After October 2015, current yields over-forecast future yields only 29.00 percent of the time;

[348] *Ibid*.

[349] *See, e.g.*, Chart 23.

[350] Because the Treasury Department discontinued issuances of 30-year Treasury bonds from March 2002 to January 2006, February 2007 was the first month for which the forecast yield was available.

from 2017 through December 2018, in only three of 24 months (about 13.00 percent of the time). That is, from 2017 through the end of 2018, the "no-change" approach under-forecast Treasury yields in 21 of 24 months.

Table 8: "No-Change" Forecast Error Observations[351]

	Feb. 2007 – Oct. 2015	Nov. 2015 – Dec. 2018	Jan. 2017 – Dec. 2018
Number of Observations			
Over-Forecast	75	11	3
Under-Forecast	30	27	21
Total	105	38	24
% Over-Forecast	71.00%	29.00%	13.00%
% Under-Forecast	29.00%	71.00%	87.00%

If Mr. Baudino wishes to consider current Treasury yields as measures of future rates, we can view the market's expectations based on the current yield curve. Those expected rates, often referred to as "forward yields" are derived from the "Expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current five-year Treasury yield, and the 25-year Treasury yield expected in five years. That is, an investor would be indifferent to (1) holding a 30-year Treasury bond to maturity, or (2) holding a five-year Treasury note to maturity, then a 25-year Treasury bond, also to maturity.[352] Here, we can apply Mr. Baudino's data to calculate the forward and current (interpolated) 25-year Treasury yield. If the forward

351 Source: Mr. Baudino's workpapers, Treasury Yields.xls; Federal Reserve Board Schedule H.15.

352 In addition to Expectations theory, there are other theories regarding the term structure of interest rates including: Liquidity Premium Theory, which asserts that investors require a premium for holding long term bonds; Market Segmentation Theory, which states that securities of different terms are not substitutable and, as such, the supply of and demand for short-term and long-term instruments is developed independently; and Preferred Habitat Theory, which states that in addition to interest rate expectations, certain investors have distinct investment horizons and will require a return premium for bonds with maturities outside of that preference.

25-year Treasury yield exceeds the current 25-year yield, that relationship indicates expectations of future rate increases.

Based on the data Mr. Baudino's Exhibit__(RAB-4), page 2, forward yields consistently exceeded current spot yields throughout 2018 (*see* Table 9, below). That is, just as economists' projections called for increased interest rates, so have forward Treasury yields.

Table 9: Forward vs. Interpolated 25-Year Treasury Yields[353]

	30-Year Treasury Yield	5-Year Treasury Yield	Forward 25-Year Treasury Yield	Interpolated 25-Year Treasury Yield
July	3.01%	2.78%	3.06%	2.96%
August	3.04%	2.77%	3.09%	2.99%
September	3.15%	2.89%	3.20%	3.10%
October	3.34%	3.00%	3.41%	3.27%
November	3.36%	2.95%	3.44%	3.28%
December	3.10%	2.68%	3.18%	3.02%
Average	3.17%	2.85%	3.23%	3.10%

Importantly, forward yields assume the current slope of the yield curve will remain constant going forward. They therefore assume the conditions supporting the current slope also will remain constant. As discussed earlier, however, Federal monetary policy continues to evolve as short-term yields are increased, and the Federal Reserve's balance sheet is unwound. Consequently, the current yield curve may not fully reflect market expectations. Nonetheless, implied forward yields certainly are known and considered by the professionals that contribute to the consensus long-term bond yield

353 Source: Exhibit__(RAB-4), page 2 of 2.

projections published by sources such as *Blue Chip Financial Forecasts*. In that case, forward yields would be reflected in economists' projections.

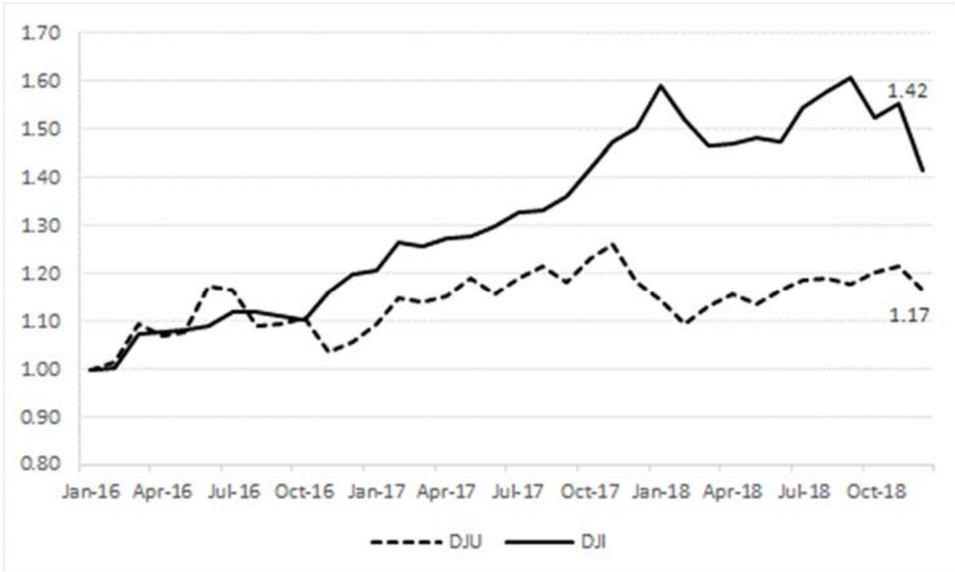
Q151. MR. BAUDINO ALSO POINTS TO INCREASES IN THE DOW JONES UTILITY AVERAGE, AND THE DECREASE IN UTILITY DEBT YIELDS AS SUPPORT FOR HIS 9.35 PERCENT ROE RECOMMENDATION.[354] WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THOSE POINTS?

A. Regarding performance of the Dow Jones Utility Average ("DJU"), an important perspective is its performance relative to the overall market. As Chart 25 (below) demonstrates, from January 2016 through December 2018 (the period included in Mr. Baudino's Table 1), the DJU significantly underperformed the overall market as measured by the Dow Jones Industrial Average ("DJI"). Notably, much of that underperformance occurred between November 2017 and March 2018, about the time the TCJA was enacted, and during which the major rating agencies noted its implications for utilities. As discussed in my Revised Direct Testimony (and in my response to the Advisors' ROE Witnesses), a reasonable inference drawn from that data is that investors began to re-evaluate utilities relative to other sectors.[355] That inference, and the related conclusion that required returns for utilities has increased, is supported by Mr. Baudino's data.

[354] Direct Testimony of Richard A. Baudino, at 10–11.

[355] Direct Testimony of Robert B. Hevert, at 59.

Chart 25: Relative Price Performance[356]



Regarding Mr. Baudino's observation that utility bond yields were lower in December 2018 than January 2016, there are several points to consider. First, over time credit spreads tend to be inversely related to Treasury yields. Data from Mr. Baudino's Table 1 display that relationship; credit spreads were negatively and significantly related to Treasury yields (*see* Table 10, below).

Table 10: Regression Statistics[357]

R Squared	21.43%	
F Stat	9.271	T Stat
Intercept	2.241	7.249
Treasury Yield	-0.327	-3.045

In 2016, the average Treasury yield and credit spreads were 2.60 percent and 1.51 percent, respectively. By 2018, the average Treasury yield increased to 3.11 percent, and the credit spread fell to 1.23 percent, from a low of 1.02 percent (February) to a high of

[356] Source: Direct Testimony of Richard A. Baudino, at 11, Table 1; Yahoo!Finance.

[357] *Ibid*.

1.41 percent (December). Simply based on the movement of Treasury yields and credit spreads since 2016, there is no reason to conclude utility bond yields indicate a lower Cost of Equity, as Mr. Baudino suggests. If anything, we may conclude that because both Treasury yields and credit spreads increased during 2018, investors' perceptions of utility risk also have increased.

VI. SUMMARY OF UPDATED RESULTS

Q152. PLEASE SUMMARIZE YOUR UPDATED ROE ANALYSES AND RESULTS.

A. I have updated many of the analyses contained in my Revised Direct Testimony, including the Constant Growth and Multi-Stage DCF analyses, the CAPM, and the Bond Yield Plus Risk Premium approach with data as of February 28, 2019. As noted in my response to the Advisors' ROE Witnesses, I have also included an ECAPM analysis and Expected Earnings analysis. Lastly, I have updated my proxy group based on recent data.[358] My updated analytical results based are provided in Table 11 below.

[358] The July 27, 2018 Value Line report for IDACORP, Inc. states its recent high stock price reflects takeover speculation. Consequently, I have removed IDACORP from my proxy group. Additionally, as enough time has passed since the merger between Great Plains Energy, Inc. and Westar Energy, Inc. to form Evergy, Inc., I have included Evergy, Inc. in my proxy group.

Table 11: Summary of Updated Analytical Results

Discounted Cash Flow	***Mean Low***	***Mean***	***Mean High***
30-Day Constant Growth DCF	8.34%	9.24%	10.23%
90-Day Constant Growth DCF	8.40%	9.31%	10.30%
180-Day Constant Growth DCF	8.48%	9.39%	10.38%
MSDCF-Gordon Method			
30-Day Multi-Stage DCF	8.64%	8.87%	9.13%
90-Day Multi-Stage DCF	8.71%	8.94%	9.20%
180-Day Multi-Stage DCF	8.79%	9.02%	9.30%
MSDCF-Terminal P/E			
30-Day Multi-Stage DCF	8.35%	8.96%	9.64%
90-Day Multi-Stage DCF	8.52%	9.13%	9.81%
180-Day Multi-Stage DCF	8.74%	9.36%	10.04%
CAPM Results		***Bloomberg Derived Market Risk Premium***	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.04%)		8.25%	9.78%
Near-Term Projected 30-Year Treasury (3.25%)		8.47%	10.00%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (3.04%)		9.29%	11.12%
Near-Term Projected 30-Year Treasury (3.25%)		9.50%	11.34%
ECAPM Results		***Bloomberg Derived Market Risk Premium***	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.04%)		9.61%	11.54%
Near-Term Projected 30-Year Treasury (3.25%)		9.83%	11.75%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (3.04%)		10.39%	12.54%
Near-Term Projected 30-Year Treasury (3.25%)		10.60%	12.76%
		Average	**Median**
Expected Earnings		10.34%	10.52%
Bond Yield Risk Premium			
	Low	***Mid***	***High***
Bond Yield Risk Premium	9.93%	9.96%	10.17%

VII. CONCLUSION

Q153. WHAT IS YOUR CONCLUSION REGARDING THE ROE FOR THE COMPANY?

A. Based on the analyses discussed throughout my Rebuttal Testimony, and the results summarized in Table 11, I conclude the reasonable range of ROE estimates is from 10.25 percent to 11.25 percent and within that range, 10.75 percent is a reasonable and appropriate estimate of the Company's Cost of Equity.

Q154. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

AFFIDAVIT

COMMONWEALTH OF MASSACHUSETTS

COUNTY OF WORCESTER

NOW BEFORE ME, the undersigned authority, personally came and appeared,

ROBERT HEVERT,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

ROBERT HEVERT

Sworn to and

Subscribed Before Me

This 12th Day of March, 2019.

NOTARY PUBLIC

SARA A. DERSTINE
MY COMM. EXPIRES
NOVEMBER 8, 2024
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTION R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

EXHIBIT RBH-14
through
EXHIBIT RBH-35

SEE ATTACHED CD

MARCH 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

ADOPTING DIRECT

AND REBUTTAL TESTIMONY

OF

MATTHEW S. KLUCHER

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Name and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew S. Klucher. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, LLC ("ESL") as Director, Utility Rates and Pricing.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am filing this Adopting Direct and Rebuttal Testimony on behalf of Entergy New Orleans, LLC ("ENO" or the "Company") before the Council of the City of New Orleans (the "Council").

Q4. ARE YOU ADOPTING THE TESTIMONY PREVIOUSLY FILED BY ANY WITNESSES ON BEHALF OF ENO IN THIS PROCEEDING?

A. Yes. I am adopting all of the Direct Testimony previously filed by Phillip B. Gillam with the exception of Section I.[1]

Q5. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. A summary of my education and work experience is included as Exhibit MSK-1.

[1] Mr. Gilliam will retire from the Company on March 31, 2019.

Q6. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. In my current position, I am responsible for retail pricing, rate design, and tariffs. In that capacity, I direct and supervise the ESL's pricing team that develops and supports pricing structures and tariffs.

Q7. HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY RATEMAKING PROCEEDINGS?

A. Yes. I have testified before the Arkansas Public Service Commission on a variety of issues including class cost-of-service studies, cost allocation, revenue distribution, rate design, customer impacts, and energy efficiency issues. A summary of my previous testimony is included in Exhibit MSK-1.

B. Purpose of Testimony

Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to certain questions and concerns raised by the City Council's Advisors ("Advisors") related to the development and mechanics of the electric and gas class cost-of-service studies and the electric and gas formula rate plans. I also address the City of New Orleans billing issues raised by the Crescent City Power Users Group ("CCPUG"). Some of my recommendations also are supported by other Company witnesses. Additionally, I note out of an abundance of caution, that my lack of discussion on a particular issue should not be construed in any way as my agreement with that issue as presented by another party.

Q9. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is divided into the following sections: (II) Class Cost of Service Study ("COS Study"), (III) Formula Rate Plan Riders ("FRP Riders") and Decoupling, (IV) Other Riders proposed by the Company and (V) City of New Orleans billing issues.

II. CLASS COST OF SERVICE STUDY

Q10. WHAT POSITIONS HAVE OTHER PARTIES TAKEN REGARDING THE ELECTRIC AND GAS COS STUDIES PRESENTED BY ENO?

A. Air Products and Chemicals, Inc.'s ("Air Products") witness Maurice Brubaker and CCPUG witness Stephen J. Baron[2] supported ENO's Electric Cost of Service ("COS") Study (which is limited to what ENO believes are properly considered base rate revenues) as reasonable. Advisors' witness, Victor Prep, rejects ENO's methodology for developing the Electric and Gas COS Studies and recommends a different approach. No other witnesses specifically address the COS Studies.

Q11. WHAT APPROACH DID THE COMPANY USE TO DEVELOP THE ELECTRIC AND GAS COS STUDIES?

A. ENO prepared a fully-allocated or fully-distributed, embedded class COS Study, limited to total base rate revenues and costs, consistent with commonly accepted cost of service

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[2] CCPUG witness Mr. Baron also supports ENO's Gas COS Study as reasonable, Direct Testimony of Stephen J. Baron on behalf of the Crescent City Power Users' Group, Council of the City of New Orleans Docket No. UD-18-07 (February 2019), p. 29.

methodologies. As part of its COS Study approach, ENO removed the revenues and corresponding costs for which the revenue requirement will be collected over a twelve-month period through a mechanism other than base rates. This adjustment was made to assure that only the Company's base rate revenue requirement was considered for rate making purposes. This approach also is used with respect to other current and proposed exact recovery riders (*e.g.*, MISO Cost Recovery Mechanism, etc.).

Q12. WHY IS IT APPROPRIATE TO REMOVE FROM THE CLASS COS STUDY FUEL AND PURCHASED POWER EXPENSE RECOVERED THROUGH A RIDER?

A. Removing fuel and purchased power expenses and revenues effectively synchronizes, or sets to zero, the expense and revenue associated with fuel and purchased power to ensure that there is no increase or decrease requested in this proceeding related to fuel expenses that are recoverable through the Fuel Adjustment Clause rider. Synchronizing fuel revenue and expenses in this manner, setting both to zero, by definition, also synchronizes sales and generation for the test year. Accordingly, the per book unbilled revenue and deferred fuel expenses amount are also not included.

Fuel and purchased power are expense items on which there is no investment, and therefore the Company earns no return. These expenses are collected through a rider mechanism that allows recovery on a dollar-for-dollar basis. This includes true-ups so that customers are asked to pay no more or no less than the actual cost of fuel and purchased power used to provide electric service. Since these revenue requirements are not included in base rates and will be tracked through a separate set of rate schedules, it is appropriate to remove these items from the class COS Study.

Q13. WHAT APPROACH HAVE THE ADVISORS PROPOSED FOR THE COS STUDY?

A. The Advisors recommend what is described as a "Fully-allocated" COS Study. They assert that "Fully-allocated" refers to an analysis of the total utility costs incurred in providing service and the total revenues of all customer classes, as well as other operating revenues derived from the use of the utility investment. To accomplish this, they recommend all expenses and revenues collected through all sources be included within the class COS Study, including those costs that will be recovered through other mechanisms other than base rates, such as fuel and purchased power.

Q14. DO YOU AGREE THAT A "FULLY-ALLOCATED" COST OF SERVICE CAN ONLY BE ACHIEVED IF ALL COST AND REVENUES ARE INCLUDED IN THE CLASS COS STUDY?

A. No. It should be noted that ENO prepared its case in this proceeding consistent with historical practice, and in ENO's last rate case, Mr. Prep did not criticize the Company for excluding non-base rate costs/revenues, nor did he recommend that ENO change the way it performed Cost of Service Studies in his prior Direct Testimony.[3] The hallmark of a fully-allocated or fully-distributed cost of service is that all costs for a utility are allocated or distributed to all classes of customers according to principles of cost causation. For example, the variable fuel costs that ENO proposes to continue to collect in riders and did not roll into the base rates are costs that would be allocated on an energy

[3] *See* Direct Testimony of Victor Prep on behalf of the Council of the City of New Orleans, Council of the City of New Orleans, Docket No. UD-08-03, (November 2008). A copy of this testimony is attached hereto as Exhibit MSK-2.

basis. Since an embedded class COS Study would allocate those costs on the same basis as the rider, the resulting proportionate share of costs by rate class is the same under either approach. Inclusion of the costs allocated and recovered through riders is an extra step to developing the class COS Studies that is not necessary to derive the same allocation of those costs.

Based on my experience working both as a member of the General Staff of the Arkansas Public Service Commission and working for Entergy Services, LLC and the numerous rate cases I have reviewed for various companies, the full allocation of costs can be accomplished accurately using the approach employed by ENO. ENO's approach effectively allocates all of its costs to the various customer classes, whether those costs are in the COS Study or in riders. The results of ENO's COS Study is a fully-allocated, embedded COS Study consistent with the principles described in the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual dated January 1992 ("NARUC Manual"), which can be used as an aid in the establishment of the base rate revenue requirement responsibility for each customer class of service. The revenue requirement responsibility for each rider is a separate issue and is determined specific to the rider by the Council.

Q15. WHY IS ENO'S PROPOSED APPROACH PREFERABLE TO THE APPROACH PROPOSED BY THE ADVISORS?

A. First, ENO's approach eliminates the potential for double or under recovery of ENO's costs, which might occur if the costs recovered through riders are included in the determination of rate base and net utility operating income, whether in a base rate case or an FRP filing.

Second, given that this instant proceeding is to establish base rates, the method employed by ENO is straight–forward, efficient, and is consistent with generally accepted ratemaking principles used in other jurisdictions. It is not clear what benefits, if any at all, are provided to the base rate setting process with Mr. Prep's proposed approach.

Q16. HAVE THE ADVISORS IDENTIFIED ANY RULES OR ORDERS FROM OTHER JURISDICTIONS SUPPORTING MR. PREP'S PROPOSAL TO INCLUDE REVENUES COLLECTED AND COSTS RECOVERED THROUGH RIDERS IN THE CALCULATION OF THE REVENUE REQUIREMENT THAT IS AT ISSUE IN THIS CASE?

A. No. In the Advisors' response to data request ENO 2-6, the Company asked what other regulatory jurisdictions require inclusion of costs recovered through fuel and other riders in a COS Study for purposes of utility rate setting. The response to ENO 2-6 is attached as Exhibit MSK-3 to my Rebuttal Testimony. The response did not identify any specific rules or orders from other jurisdictions that support the Advisors' proposal; it only pointed generally to four utility industry references. However, it is not clear how the principles set forth in these references are applied in practice in a manner that is consistent with the proposal.

For example, in the Advisors' response to ENO 2-6, one of the references that purports to support the Advisors' proposal is an extract from the NARUC Manual. The provided reference highlights various phrases and words throughout the document that include total utility revenue requirement, total cost of providing service, and the word total. However, the NARUC Manual does specifically address how to treat costs that are recovered through exact recovery riders, such as fuel and purchased power. The NARUC Manual also affirmatively states on page 25, when describing pro forma adjustments, that "[t]he goal is to adjust the actual costs to present normal operating conditions as accurately as possible, so that rates resulting from a proceeding are appropriate for application in the immediate future. An example of costs that may require adjustment or normalization are power production and purchased power expenses." This would be consistent with the synchronization adjustment ENO has made to fuel and purchased power.

Q17. WHY IS A SYNCHRONIZATION ADJUSTMENT TO FUEL AND PURCHASED POWER NECESSARY?

A. The inclusion of fuel in the class COS Study requires adjustments to offset the fuel expense and revenues to assure that the COS Study provides an accurate measure of the base rate revenue requirement. Synchronizing or offsetting the fuel expense and revenues will account for the deferred expense component of fuel and purchased power. Synchronization ensures that no increase or decrease in revenue requirement is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel adjustment clause, including deferred fuel expenses.

Q18. WOULD ALL EXPENSES IF RECOVERED THROUGH A RIDER NEED TO BE SYNCHRONIZED IF INCLUDED IN THE COS STUDY?

A. Yes. It is more appropriate and straightforward to remove these items from the COS Study. If rider costs are included in the COS Study, the synchronization adjustment is necessary to ensure that these costs do not impact the total base rate revenue requirement requested in this proceeding.

Q19. DO YOU HAVE ANY OBSERVATIONS REGARDING THE OTHER REFERENCES PROVIDED IN THE ADVISORS' RESPONSE TO ENO 2-6?

A. Yes. Another reference identified in the response was an extract from a training presentation on cost allocation and rate design presented to the Oklahoma Corporation Commission by a representative from the National Regulatory Research Institute in March 2017. The training presentation contains a highlighted bullet point on page 4 that states "[t]he revenue requirement represents the total cost of providing service." However, the referenced material does not expressly address the treatment of expenses recovered through riders.

To gain further insight regarding what approach to developing a COS Study is used in practice before the Oklahoma Corporation Commission, I reviewed the Direct Testimony of Jason J. Thenmadathil on behalf of Oklahoma Gas and Electric Company ("OG&E") filed before the Oklahoma Corporation Commission on January 16, 2018 in Cause No. PUD 201700496, and Mr. Thenmadathil explained that the utility's pro forma adjustments remove costs recovered elsewhere, such as fuel and purchased power related costs that are recovered through OG&E's Fuel Adjustment Clause rider. His reasoning for this adjustment was similar to mine – "to ensure that customers are not double charged for fuel costs recovered through a separate recovery mechanism." This adjustment was supported and recommended for approval by the Public Utility Division of the Oklahoma Corporation Commission.[4] Given this example of what actually occurs in Oklahoma,[5] I conclude that the author of the training presentation did not intend to make a statement on the full scope of revenue requirements presented to the Oklahoma Corporation Commission for consideration of a COS Study. Attached as Exhibit MSK-4, *in globo,* are the referenced testimonies filed in Oklahoma Corporation Commission Cause No. PUD 201700496.

Q20. DO YOU HAVE ANY OTHER OBSERVATIONS WITH THE ADVISORS' APPROACH TO DEVELOPING THE TOTAL COST OF SERVICE?

A. Yes. On page 14 of Mr. Prep's Direct Testimony, he describes his development of the Utility's Total Cost of Service in two basic steps. He explains that in the first step he used the allocation factors "to conduct appropriate allocations of each operating expense and rate base component of the total cost of service to customer rate classes." Mr. Prep then explains that he next "made reasonable adjustments to the [before-tax] rates of return for each customer rate class relative to present total revenues by customer class to

4 *See* Exhibit MSK-4, Direct Testimony of Jason J. Thenmadathil and Responsive Testimony of Geoffrey M. Rush filed before the Oklahoma Corporation Commission, Cause No. PUD 201700496, page 11 and 55.

5 *See In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma*, Corporation Commission of the State of Oklahoma, Cause No. PUD 201700496, Order No. 679358 (June 19, 2018).

develop the composite total utility [before-tax] return on rate base such that the total utility revenue requirements are achieved."

It is the second step that is inconsistent with generally-accepted cost of service principles. At this step Mr. Prep begins combining the concepts of cost of service principles with the concept of rate design principles. The designing of rates is the fourth step in the four-step process to developing rates described on page 13 in the NARUC Manual. While the NARUC Manual mainly addresses cost allocation, which is the third step, the NARUC Manual does recognize that rates are generally not designed in the fourth step strictly by the results of the class COS Study completed in the third step. It states the regulators design rates using the costs incurred by each class as a major determinant. However, the NARUC Manual continues to explain that other non-cost attributes are considered by regulators in designing rates such as revenue-related considerations and rate continuity for the customer. While I agree that regulators are not required to strictly follow COS Study results, I would not characterize an approach that applies varying before-tax rates of return as class cost of service. This issue is further addressed by Company witness Myra L. Talkington.

Finally, the before-tax rate of return concept that Mr. Prep has proposed essentially ignores how the Company calculates taxes, as well as how taxes are allocated to the various customer classes within the class COS Study. Mr. Prep's approach also provides no gross up on the incremental income for bad debt and regulatory commission expense. However, in his deposition he indicated that he is not opposed to an adjustment to account for bad debt and regulatory commission expense.[6]

Q21. WERE YOU ABLE TO REPLICATE THE ADVISORS' ELECTRIC AND GAS COS MODEL AS IT RELATES TO MR. PREP'S EXHIBIT VP-9 AND VP-11?[7]

A. No. Mr. Prep presents the results of the Electric COS Study in Exhibit VP-9 and the Gas COS Study in VP-11; however, the allocation of cost by class is not consistent with the COS Models provided by the Advisors. Mr. Prep has acknowledged the issue in deposition[8] and it is my understanding that the Advisors provided supplemental information on March 21, 2019. I have been unable to fully assess the intent of the Advisors' testimony due to late receipt of this information and unreconciled exhibits and work papers. At this time, ENO is not certain it would be able to replicate Mr. Prep's approach if the Council were to approve such for future rate base proceedings.

Q22. DOES ENO'S APPROACH TO DEVELOPING BASE RATES CONSIDER TOTAL COMPANY REVENUE REQUIREMENT?

A. Yes. ENO's recommended approach provides the total base rate and rider revenues by class, as shown in Statement AA-2. This provides the opportunity to consider all

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[6] *See* Exhibit MSK-5, *in globo*, Excerpts from the Transcript of the Deposition of Victor Prep taken on March 14, 2019 at p. 86.

[7] The Company reserves the right to supplement or amend this testimony based on any changes reflected in Mr. Prep's revised exhibits received on March 21, 2019.

[8] Id, pp. 75-80.

revenues and costs when setting base rates. In fact, ENO's proposed revenue allocation by rate class used in designing base rates considered the impact by class on a total revenue basis.

Q23. WHAT IS YOUR RECOMMENDATION REGARDING THE DEVELOPMENT OF THE COS STUDIES IN THIS PROCEEDING?

A. I recommend the Electric and Gas COS Studies be developed using the method I described above consistent with ENO's Direct Application. However, if the Council approves an Electric and Gas COS Study approach that ultimately includes all costs and revenues, as explained earlier, it will be necessary to require the synchronization of the expenses and revenues associated with riders in this proceeding and in any future FRP that is implemented.

III. FORMULA RATE PLAN RIDERS AND DECOUPLING

Q24. WHAT POSITIONS HAVE OTHER PARTIES TAKEN REGARDING THE ELECTRIC AND GAS FRPS PRESENTED BY ENO?

A. The Advisors, CCPUG, and Air Products recommend the approval of the Electric and Gas FRP with certain modifications. No other party specifically addresses the Electric and Gas FRP. The modifications proposed by CCPUG and Air Products are addressed by Company witness Joshua B. Thomas. I address recommendations proposed by the Advisors regarding what cost to include in the Electric and Gas FRPs and their proposal for decoupling within the Electric FRP, other policy issues regarding the Advisors' recommendations to modify ENO's proposed FRP are addressed by Mr. Thomas.

A. Costs Included in the FRP

Q25. WHAT COST DID MR. PREP RECOMMEND BE INCLUDED IN THE ELECTRIC AND GAS FRPS?

A. Consistent with his recommendation for the class COS Studies, Mr. Prep recommended that all costs and revenues, including those recovered through riders, be included in the FRPs. The reasons I do not support this approach have already been addressed in Section II.

Q26. WHAT COSTS SHOULD BE INCLUDED IN THE FRP?

A. Consistent with my recommendation for the COS Studies, only those costs that are to be collected through base rates should be included in the FRP. This will ensure that costs that are recovered through riders are not double-counted in the FRP formula.

B. Advisors' Decoupling Recommendation

Q27. WHAT IS THE ADVISORS' ELECTRIC FRP DECOUPLING RECOMMENDATION?

A. Mr. Prep recommends that the decoupling adjustment be performed by applying the same allocation methodology approved in this proceeding. However, to accomplish this adjustment he recommends the Company provide a new COS Study each year by updating the allocation factors for each customer class with then-current customer data. He explains that this adjustment would also include a potential redetermination of the before-tax rates of return for each customer class relative to the final rate class revenues approved in this proceeding.

Q28. WHAT IS THE COMPANY'S REACTION TO MR. PREP'S DECOUPLING RECOMMENDATION?

A. The Company has significant concerns that this requirement would substantially undermine the purposes and efficiencies of an FRP. Further, it is the Company's position that there is minimal benefit to be gained from developing updated allocation factors and presenting a fully-developed COS Study each year. Such an exercise would result in a significant amount of additional work that will challenge the FRP timeline, including the Company's ability to timely file the initial Evaluation Report and the parties' opportunity to review the filing. In addition, it is an inefficient use of resources in a process that is designed to streamline ratemaking and regulatory review. It would be tantamount to filing a rate case each year.

During rate proceedings the major areas of contention revolve around the utility's revenue requirement, the allocation of the revenue requirement to the various rate classes, and rate design. The FRP process generally eliminates two of these three potentially contentious areas and allows the parties to focus on those costs included in the revenue requirement. This approach is generally accepted for the 3 to 5 year term of an FRP because, typically, there are no substantial changes in operations from year to year that would materially affect cost allocations among customer classes. The approach recommended by Mr. Prep will add the allocation of the revenue requirement back to the FRP proceeding.

Generally, in an FRP process, it is not necessary to recalculate allocation factors each year and adding this step is counter to the efficiencies gained from using an FRP. Moreover, Mr. Prep is not proposing that the Council adopt rates based strictly on the results of the COS Study (or on any objective standard) in this case, nor is he recommending that rates strictly be adopted based on any change in cost of service that may result from updating the external allocation factors in the FRP process.

C. Annual Recalculation of Allocation Factors

Q29. PLEASE EXPLAIN WHAT EFFORTS WOULD NEED TO BE UNDERTAKEN BY THE COMPANY TO COMPLY WITH MR. PREP'S RECOMMENDATION TO ANNUALLY UPDATE ALLOCATION FACTORS?

A. While it is not yet exactly clear what level of supporting detail workpapers will be required of ENO as part of its annual FRP filing, to comply with the Advisors' proposal, the level of work to develop the allocation factors for the FRP will be no different than if ENO was developing allocation factors for a rate case. The basic COS Model is generally an automated application that relies on the input of data collected from various organizations within the Company. Given this automated process, the COS Model itself is generally not difficult to produce once the input data is available. However, the development of the data is very labor intensive and requires numerous resources. In particular, the process for developing external allocation factors is a systematic approach that requires the gathering of vast amounts of data from various systems that are subject to various analytical analyses. The Company does not routinely update the demand, energy, and customer-related allocation factors as part of its normal ongoing business; the process would require more resources than the Company has available at this time.

In order to develop external allocation factors, analysts in the Utility Pricing and Analysis group gather detailed customer-level data from the Company's customer record systems. This data has to be assigned to the proper rate class and voltage level classification and then analyzed to properly account for out-of-period cancel/rebills and other non-recurring anomalies. Typically, this process can't begin until two to three months following the end of the test year in order to include all revised billings occurring during the final months of the test year. The resulting data includes kilowatt hour ("kWh"), billed kW and customer counts by rate class and voltage level. Detailed information has to be pulled from the source systems then the data has to be verified and assigned to rate classes. This information is then used for two purposes: (1) to develop energy allocation factors, and (2) it is provided to Customer Load Information ("CLI") for use in developing peak demands for use in demand related allocation factors. CLI uses this data, along with additional data including "at generation" hourly load shapes and hourly metered demand data from each rate classes' load research sample to develop monthly demands by rate class and voltage level at the time of the system peak (also called jurisdictional peak or coincident peak), maximum diversified demand (MDD), and non-coincident peak (NCP) hours.

Q30. ADVISORS' WITNESS MR. PREP DOES NOT AGREE THAT THE RECALCULATION OF ALLOCATION FACTORS FOR EACH FRP EVALUATION REPORT WOULD BE A WASTE OF RESOURCES.[9] PLEASE EXPLAIN WHY IT WOULD BE INEFFICIENT TO FOLLOW MR. PREP'S RECOMMENDATION.

A. Unless there is a significant change in the way a utility operates to provide service to its customers or a significant shift in the utility's customer base, allocation factors generally do not change in any material way from year to year. The process I described above to develop the external allocation factors will require at least two to four analysts working primarily on the development of allocation factors for a period of four to six weeks. The majority of the processes described above are assigned to the CLI group and the Utility Pricing and Rates ("UP&A") group. Each group would need to assign up to two analysts to the process to complete the analysis in a timely manner. This would require allocating two of the three analysts in CLI and two of the four analysts in UP&A to the task for a period of four to six weeks.

The Advisors' recommendation will require the Company to undertake efforts similar to that employed in the preparation of a full rate case, adding an estimated 30 days to the filing timeline as compared to the Company's proposed Electric and Gas FRP and will require substantially more resources dedicated to the preparation of the annual FRP Evaluation Report. Consequently, not only would the regulatory efficiencies that a FRP is intended to provide be substantially eroded, there would be increased costs incurred and allocated to customers as opposed to cost savings.

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9 Direct Testimony of Victor Prep, page 79.

Q31. ARE THERE OTHER INSTANCES WHERE THE ADVISORS APPEAR TO HAVE TAKEN A DIFFERENT POSITION REGARDING THE NEED FOR UPDATING ALLOCATION FACTORS?

A. Yes. ENO data request 2-8 to the Council's Advisors asked whether Electric and Gas AMI Allocation Factors presented in Courtney A. Crouch's testimony must be updated annually in the Electric and Gas Formula Rate Plans. In that response, the Advisors indicate that the allocation factors would not be updated annually.[10]

Q32. IS THE ADVISORS' PROPOSED COST ALLOCATION METHODOLOGY IN THE CASE DRIVEN BY THE EXTERNAL ALLOCATION FACTORS?

A. No. The external allocation factors applied in the COS Studies have only partial impact on the Total Cost of Service developed by the Advisors. This is demonstrated on Mr. Prep's Exhibit VP-9,[11] which is the Advisors' Recommended Electric Revenue Requirements by Rate Class. Based on the external allocation factors applied in the Electric COS Study, the Residential rate class is allocated 55% and 48% of ENO's Total Company Adjusted Rate Base and Operating Expenses, respectively. This would indicate that the total cost to serve the Residential class would be at least 48% of the total Company Cost of Service. However, line 16 on Exhibit VP-9 with the description of "Total Cost of Service" shows Residential at only 44% of the total Company. This

[10] See Exhibit MSK-6 attached hereto.

[11] This statement refers to the Mr. Prep's original VP-9. The Company reserves the right to supplement or amend this testimony based on any changes reflected in Mr. Prep's revised exhibits received on March 21, 2019.

demonstrates that external allocation factors are not driving the purported Total Cost of Service results developed by the Advisors' approach.

Q33. IF THE EXTERNAL ALLOCATION FACTORS ARE NOT DRIVING THE TOTAL COST OF SERVICE, WHAT IS?

A. As I explained above in Section II, the different required before-tax rates of return on rate base assigned by Mr. Prep to each rate class is a principal driver of the Total Cost of Service by customer class. I say "assigned" because they were not calculated through an objective, replicable process. In a data request response, which is included as Exhibit MSK-7[12] the Advisors indicate that "[n]o specific algorithm was used to arrive at customer class rates of return on rate base allocated to customer classes." Mr. Prep further confirmed through his deposition that no objective standard was used in determining the relative rates of return for the respective classes.[13]

Q34. WOULD THE RELATIVE BEFORE-TAX RATE OF RETURN BY RATE CLASS REMAIN CONSISTENT IN FUTURE FRP FILINGS?

A. No. Based on my understanding of Mr. Prep's recommendation, that would be an issue that ENO, the other Parties, and the Council would be required to address each year. On page 79 of his Direct Testimony, Mr. Prep states "[t]he allocation methodology of FRP evaluation period costs should be applied consistent with the allocations applied in this

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[12] Exhibit MSK-7, Advisors' Response to ENO data request Advisors 2-10.

[13] *See* Exhibit MSK-5, *in global*, Excerpts from the transcript of the deposition of Victor Prep taken on March 14, 2019 at pp. 37-38.

proceeding to determine the decoupling revenue adjustments by customer class. That methodology would include an updated consideration of the before-tax rates of return for each customer class based on the final rate class revenues approved in this proceeding."

My understanding is that Mr. Prep is recommending that ENO be required to go through a lengthy process of updating the external allocation factors and present a fully-developed COS Study each year to only then modify the results (by varying the before-tax rate of returns by class) to a level that is considered acceptable. Mr. Prep confirmed this approach in his deposition in which he stated that the return component would be evaluated in whatever fashion the Council evaluates it this rate case.[14]

Q35. IF THE COUNCIL WERE TO ADOPT DIFFERENT BEFORE-TAX RATES OF RETURN ON RATE BASE FOR EACH RATE CLASS, WOULD THAT BE CONSISTENT WITH THE DIRECTIVE IN RESOLUTION R-16-103 TO UPDATE ANNUALLY THE FIXED-COST CUSTOMER RATE ALLOCATION FACTOR?

A. No. It would not because the different required before-tax rates of return on rate base are not allocation factors and their determination did not and would not follow a methodology. Resolution R-16-103 contemplated an allocation methodology that could be updated and applied consistently on an annual basis. Applying different before-tax rates of return to allocate costs is not consistent with resolution.

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14 *See id.* at page 25.

Q36. WHAT COULD BE UPDATED CONSISTENT WITH THE SPIRIT OF RESOLUTION R-16-103 TO CALCULATE THE RATE CLASS REVENUE REQUIREMENTS?

A. ENO proposes that the proposed revenue by rate class approved in this proceeding be used to allocate ENO's revenue requirement in future FRP evaluation reports. This would be consistent with the spirit of Resolution R-16-103 and consistent with the revenue allocation approved in this proceeding.

Q37. WHAT IS YOUR RECOMMENDATION REGARDING THE MECHANICS OF THE DECOUPLING PROPOSAL IN THE CONTEXT OF THE FRP?

A. I recommend that the Council adopt ENO's proposal, which uses the revenue allocation ultimately approved by the Council in this rate case as the basis for the allocation of the revenue requirements presented in the annual FRPs, consistent with historical practice before the Council.

Q38. DOES ANY OTHER PARTY PROVIDE DECOUPLING RECOMMENDATIONS?

A. Yes. Alliance witness Pamela G. Morgan recommends a different approach to decoupling. Based on the Company's current understanding of Ms. Morgan's recommendation, the Company believes her recommendation may have some merit and if implemented effectively would further moot Mr. Prep's recommendation to updated COS allocation factors annually. Company witness D. Andrew Owens addresses the decoupling recommendation proposed by Ms. Morgan.

IV. OTHER RIDERS PROPOSED BY THE COMPANY

Q39. DID ANY PARTIES ADDRESS THE OTHER RIDERS PROPOSED BY ENO IN ITS DIRECT CASE?

A. Yes. While no parties address the mechanics of the riders themselves, the Advisors and CCPUG have cited certain policy reasons why they recommend the Council reject the revised Purchased Power Capacity Acquisition Cost Recovery Rider, the Gas Infrastructure Replacement Program Rider and the Distribution Grid Modernization Rider. Company witness Mr. Thomas addresses the issues raised by the parties regarding these riders.

V. CITY OF NEW ORLEANS BILLING ISSUES

Q40. IN HIS DIRECT TESTIMONY, MR. BARON RECOMMENDS THAT THE COUNCIL REQUIRE ENO TO ESTABLISH A WORKING GROUP, FOLLOWING COMPLETION OF THE RATE CASE TO ADDRESS PURPORTED BILLING ISSUES. IS THIS NECESSARY?

A. No. Mr. Baron claims his recommendation is based on discussions with representatives of the City about “a number of aspects” regarding the summary billing of more than 1,000 separate accounts under which the City takes electric and gas service. I would first note that Mr. Baron does not identify the “aspects of billing” that the City claims to be at issue. I would also note that in addition to preparing and delivering the monthly summary bill of accounts that Mr. Baron references, the City receives a collective bill (by Department) and a detailed monthly bill (by account) for each of the City’s accounts. The collective and detailed bills are produced by the Company’s billing system, whereas the summary bill is compiled manually. Each summary bill requires approximately 40 man-hours to complete and verify.

Mr. Baron has offered no evidence of any economies of scales attributable to the volume of the City's accounts. In fact, it is my understanding that producing the monthly summary bill for numerous City accounts requires a level of service that is not replicated for any other ENO customer. Further, the account information produced in the summary billing is accessible through Entergy's myEbusiness online portal. Through the myEbusiness portal, business customers are able to:

- View current account detail summary
- View/Print bill image (up to past 24 months)
- View Meter History (up to 24 months)
- Export Meter History Reports
- View Billing History (up to 24 months)
- Export Billing History Reports
- Maintain Users - set user restrictions, invite users
- Maintain Account Groups/Assign Account; and
- View Outage(s).

In the near future, customers with access to myEbusiness will also observe enhancements that are currently in the testing phase, including enhanced options for payment.

Q41. DO YOU PROPOSE AN ALTERNATIVE TO MR. BARON'S RECOMMENDATION?

A. Yes. The City of New Orleans has an assigned account representative who serves as a liaison between the City administration and the Company. Any time there is a customer service-related issue, that account representative is available to work through those issues and escalate them to ENO management where appropriate. Since commencement of this proceeding, representatives from ENO and from the City have met on two occasions. During those meetings, representatives from the City have identified several items that the Company views as customer service-related issues, such as identifying the rate schedule under which an account takes services in addition to the rate code currently stated on bills, among others. The Company believes these discussions have been productive and proposes to continue the periodic meetings to address any remaining outstanding customer service-related issues that the City may have with its accounts.

On the other hand, when the City seeks to modify a rate under which it takes service, that must occur through a rate proceeding in which the City must identify the specific issue and presents evidence required to support the proposed modification(s). The City has failed to identify specific issues or present evidence that the COS Study and/or proposed rate design are inappropriate as it relates to municipal accounts. Mr. Baron's proposed working group cannot serve as a substitute for failing to undertake the necessary steps in this proceeding to meet regulatory requirements for modifying rates.

Q42. DOES THIS CONCLUDE YOUR REVISED DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared,

MATTHEW KLUCHER,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

MATTHEW KLUCHER

Sworn to and

Subscribed Before Me

This 14th Day of March, 2019.

NOTARY PUBLIC

J. ANDREW LEWIS, JR.
Notary Public
State of Louisiana
Notary ID # 133686
My Commission is for life.

Matthew S. Klucher - Summary of Education and Work Experience

I received a Bachelor of Science degree in Mathematics and Minor in Statistics from the University of Arkansas at Little Rock in 1997. In April 2018, I accepted my current position with Entergy Services LLC. ("ESL"). Prior to joining ESL I worked for the General Staff of the Arkansas Public Service Commission. I began my career with Arkansas Public Service Commission in March 2010 as a Rate Analyst in the Cost Allocation and Rate Design Section where I was involved with developing class Cost of Service Studies, evaluating rate design, and reviewing utility sponsored energy efficiency programs. In September 2012, I was promoted to Director of the Cost Allocation and Rate Design Section. Prior to joining the Staff of the Arkansas Public Service Commission, I worked in the telecommunication industry in wholesale tariff administration and billing as a Senior Analyst for Windstream Communications, and prior to that I was Senior Analyst with Alltel Wireless in the Strategic Pricing group.

I have received specialized utility training by completing the Advanced Regulatory Studies Program at Michigan State University's Institute of Public Utilities, the Introduction to Cost of Service Concepts and Rate Design for Electric Utilities sponsored by EUCI, the Electric Industry Regulation Course at New Mexico State University's Center for Public Utilities, the Certified Energy Management Courses sponsored by the Association of Energy Engineers and the Energy Efficiency Management Certificate Program sponsored by the American Public Power Association. I have received training from the Association of Energy Engineers and have qualified as a Certified Energy Manager (CEM), License No. 21109.

Arkansas Public Service Commission Testimony:

Electric Rate Cases

1. Direct, Sur-rebuttal, and Settlement Testimony (2017). Docket No. 16-052-U (Oklahoma Gas and Electric Company). General Change in Rates, Charges, and Tariffs. On behalf of the general Staff of the APSC. Issues: class cost of service, revenue distribution, rate design, customer charges, and customer bill impacts.

2. Settlement Testimony (2016). Docket No. 15-015-U (Entergy Arkansas, Inc.). Change in Rates for Retail Electric Service. On behalf of the general Staff of the APSC. Issues: forecasted billing determinants and revenues, class cost of service, revenue distribution, rate design, customer charges, and customer bill impacts.

3. Settlement Testimony (2014). Docket No. 13-111-U (The Empire District Electric Company). Change in Rates and Tariffs. On behalf of the general Staff of the APSC. Issues: forecasted billing determinants and revenues, class cost of service, revenue distribution, rate design, and customer bill impacts.

4. Direct and Sur-rebuttal Testimony (2013). Docket No. 13-028-U (Entergy Arkansas, Inc.). Change in Rates for Retail Electric Service. On behalf of the general Staff of the APSC. Issues: class cost of service and revenue distribution.

Natural Gas Rate Cases

1. Settlement Testimony (2016). Docket No. 15-098-U (CenterPoint Energy Arkansas Gas). General Change or Modification in its Rates, Charges, and Tariffs. On behalf of the general Staff of the APSC. Issues: forecasted billing determinants and revenues, class cost of service, revenue distribution, rate design, customer charges, and customer bill impacts.
2. Settlement Testimony (2014). Docket No. 13-079-U (Sourcegas Arkansas, Inc.). General Change in Rates and Tariffs. On behalf of the general Staff of the APSC. Issues: forecasted billing determinants and revenues, class cost of service, revenue distribution, rate design, and customer charges.

Water Rate Cases

1. Direct and Sur-rebuttal Testimony (2010). Docket No. 09-130-U (United Water Arkansas, Inc.). General Change in Rates and Tariffs. On behalf of the General Staff of the APSC. Issues: forecasted billing determinants and revenues.

Energy Efficiency Testimony

Various energy efficiency testimonies in Docket No.'s: 13-002-U, 10-100-R, 08-072-TF, 07-085-TF, 07-083-TF, 07-082-TF, 07-81-TF, 07-079-TF, 07-078-TF, 07-077-TF, 07-076-TF, 07-075-TF.

Various Self-Direct testimonies in Docket No.'s: 11-137-SD, 11-136-SD, 11-131-SD, 11-126-SD, 11-125-SD, 11-124-SD, 11-123-SD, 11-120-SD, 11-118-SD, 11-111-SD, 11-109-SD, 11-104-SD, 11-101-SD, 11-095-SD, 11-093-SD.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, INC.	**)**	
FOR A CHANGE IN ELECTRIC	**)**	
AND GAS RATES PURSUANT TO	**)**	**DOCKET NO. UD-08-03**
COUNCIL RESOLUTION NO. R-06-459	**)**	

DIRECT TESTIMONY

OF

VICTOR PREP

ON BEHALF OF

COUNCIL OF THE CITY OF NEW ORLEANS

NOVEMBER 17, 2008

PREPARED DIRECT TESTIMONY

OF

VICTOR PREP

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Victor Prep. My business address is 8055 East Tufts Avenue, Suite 1250, Denver, Colorado. I am a registered Professional Engineer in the Commonwealth of Pennsylvania and an Executive Consultant with the firm, Legend Consulting Group Limited ("Legend").

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Council of the City of New Orleans ("Council" or "CNO"). The Council regulates the rates, terms, and conditions of electric and gas service of Entergy New Orleans, Inc. ("ENO" or "Company") and a portion of the electric service of Entergy Louisiana, LLC. ("ELL") located within the Orleans Parish. Both ENO and ELL are Operating Company affiliates of Entergy Corporation ("Entergy").

Q. PLEASE SUMMARIZE YOUR RELEVANT EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. Exhibit No. ___ (VP-2) provides a summary of my relevant education and professional experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

1. Present a fully allocated cost of service analysis by rate schedule for the electric and gas utilities based on the rate of return recommended by CNO Witness Proctor and the CNO adjustments as recommended by CNO Witnesses Mathai, Rogers and Vumbaco.

2. Propose total revenues for each rate schedule based on the allocated cost of service analysis that I conducted and specific allocated rates of return for each rate.

3. Propose revenue recovery resulting from a revised fuel adjustment clause and revised base rate tariffs employing the proposed total revenues for each rate schedule.

4. Define the demand, energy and customer components of the allocated cost of service and combine them with billing determinants for cost based rate proposals to the tariff structure.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND ITS MAJOR CONCLUSIONS OR RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. I have proposed revenues for each rate schedule that will achieve the Company revenue requirement. Those proposed revenues were based on allocated cost of service results for each rate schedule, adjusted to maintain reasonable changes relative to all rate schedules. This approach is consistent with the principles of rate continuity and the avoidance of undue rate shock. The proposed revenues are an acceptable balance between improved rates of return and reasonable relative changes in revenue among the rate schedules.

2. I recommend that a load research program be instituted for all sampled customers and structured to provide comprehensive data on load characteristics for each rate schedule every two years.

3. I recommend that voltage level loss factors be updated annually, and used in conjunction with the load research data and fuel adjustment clause calculations.

4. I recommend that the fully allocated cost analysis be streamlined, structured to support rate design, and updated periodically. It should include all customers served, including gas non jurisdictional (“NJ”)

customers. An improved cost analysis would provide the Council and the Company a valuable and contemporaneous reference to evaluate rate relationships among all rate classes.

5. Finally, I recommend a complete rate design study that was required by the 2006 Agreement in Principle.

II. ELECTRIC OPERATIONS

Q. PLEASE SUMMARIZE THE RESULTS OF THE FULLY ALLOCATED COST OF SERVICE ANALYSIS FOR ENO'S ELECTRIC UTILITY.

A. The fully allocated cost of service analysis was developed for the projected year 2008, Period II, using the rate of return recommended by CNO Witness Proctor and the CNO adjustments as recommended by CNO Witnesses Mathai, Rogers and Vumbaco. Revenues for existing rates and the corresponding allocated rates of return of the electric utility are summarized in Exhibit No. ___ (VP-3).

Q. CAN YOU SUMMARIZE THE ALLOCATION METHODS USED IN THE ANALYSIS?

A. Each item of the cost of service was analyzed to determine the appropriate method of allocation, while functionally grouping the costs as demand, energy, and customer related. The demand related costs at the bulk power supply level were allocated on the basis of the average of the contributions to the twelve months coincident peaks ("CP"). Demand related costs below that level were allocated on the basis of non-coincident demands. Energy related costs were allocated on the basis of annual megawatt-hour sales. Customer related costs were allocated using the customer allocation factors developed by ENO.

Q. DID YOU REVIEW THE COMPANY'S FORECAST FOR PERIOD II?

A. ENO's forecast affects allocation factors in the cost analysis and billing determinants in setting rates. However, it was not possible to do a detailed examination of the forecast of ENO's annual megawatt-hour sales or peak loads, because ENO did not provide the information necessary to accomplish a complete review. ENO's responses to CNO data requests 29-1, 29-3, 4-6, and 21-5 concerning questions related to forecasted data produced little or no useful information.

Q. WHAT ADDITIONAL INFORMATION CAN BE USED TO CHECK THE FORECAST DATA USED IN PERIOD II?

A. On October 31, 2008 ENO made a filing with the Council that provided the results of its year to date performance through the third fiscal quarter of 2008. That ENO third quarter data was received on November 3, 2008, so there was not sufficient time to use that actual data to compare with Period II data in ENO's July 31, 2008 filing and incorporate the results in my direct testimony. This comparison with actual data will be addressed in the next round of my testimony and the impact on the cost analysis and rate schedule revenue proposals will be evaluated at that time.

Q. HOW DID YOU DEVELOP THE DEMAND ALLOCATION FACTORS?

A. The proper procedure would be to use current load research sample data and loss factor studies to construct a composite of each month's peak demand. Without that data being available from ENO, I examined the allocation factors ENO developed from 2004 pre-Katrina data. Demand allocation factors are estimated values, but they are the foundation blocks for allocated cost analysis. It is important to use the most current and complete load research data because of the impact on the cost allocation results. Essentially, ENO estimates of monthly coincident peak demands for each rate schedule and voltage level were used with loss factors to construct a total peak demand composite for each month of Period I. ENO used estimates of coincident peak demands for each rate schedule for Period II, but did not construct monthly composites correlating to system peaks. I performed that analysis to evaluate the demand allocation factors.

Q. WHAT CONCERNS DID YOU NOTE IN THAT PROCESS?

A. I examined ENO's development of monthly peak demand composites for Period I data, and noted that demand estimates produced differences from 5 to 12 percent for several months' peaks. As discussed below in my testimony, this can not be remedied until such time as more comprehensive and current load research and loss data is obtained. This procedure was not only omitted for Period II demand allocation factors, but with no adjustments by ENO similar to Period I, the concern I have is the system peak values that correlated with ENO's estimated coincident peak demands. I constructed a demand composite for each Period II month, and noted that ENO's Period II coincident demand estimates showed noticeable variances from the monthly Entergy system peaks.

Q. WHY DO YOU CONSIDER THE CONTRIBUTIONS TO THE ENTERGY SYSTEM PEAKS TO BE SIGNIFICANT?

A. As an Entergy Operating Company, ENO's bulk power supply costs are very much influenced by the System Agreement. The purpose of the System Agreement is to provide the contractual basis for the planning, construction, and operation of the electric generation, transmission, and other facilities of the Entergy Operating Companies in such a manner as to achieve economies consistent with the highest practicable level of service reliability. The System Agreement Service schedule MSS-1, for reserve equalization, and service schedule MSS-2 for transmission equalization provide for the sharing of generation reserves and the equalization of all transmission costs above 115kV. Pursuant to the System Agreement, these specific costs and benefits are shared among the Operating Companies on the basis of the contributions of each company to the twelve monthly Entergy System peaks. Other production and transmission level costs are related to the twelve monthly peaks of ENO.

Q. WERE YOU ABLE TO COMPUTE THE CONTRIBUTIONS TO THE TWELVE MONTHLY ENTERGY SYSTEM PEAKS?

A. The coincident demand estimates from ENO data were used to develop a composite of those twelve peaks, but some adjustment had to be made to correlate with the System's peak values. The resulting twelve month CP allocation factor ratios were not substantially changed. As soon as available, the use of current load research data applicable to those peaks would produce a more improved and much better set of results.

Q. DID YOU MAKE ANY OTHER CHANGES TO THE ELECTRIC DEMAND ALLOCATION FACTORS?

A. Yes. In the ENO cost allocation model, the capacity cost responsibility for the interruptible customers was reduced approximately 80 percent (80%). However, there is no substantial record of reduction or curtailment of these loads during peak conditions. The ENO cost of service model, as filed, was iterated to determine the change in rate of return for interruptible customers when their production cost demand allocator was varied from the ENO reduced demand to actual demand. The rate of return for interruptible customers changed from ninety-nine percent (99%) to sixty-nine percent (69%). This is primarily due to the low production investment cost of ENO. While it is necessary to recognize that the company has the contractual ability to interrupt that large load, a lesser reduction was applied to that demand allocation factor. Fifty percent (50%) or half of the highest demands for the twelve months were used as the allocation factor for these customers. This is equivalent to only seventy-three percent (73%) of their average demand and is an equitable allocation relative to the rest of the rate schedules.

Q. ON WHAT BASIS DID YOU PROPOSE NEW TOTAL REVENUES FOR EACH RATE SCHEDULE?

A. Using the results of the allocated cost of service analysis, I varied the allocated rates of return for each rate schedule to determine the corresponding total revenue changes for each customer group. Lower rates of return were raised, and reasonable percentage changes to each rate schedule's total revenue were maintained. This process was continued until the composite of these allocated revenues was equal to the allowed total revenue requirement of the electric utility.

Q. CAN YOU SUMMARIZE THE RESULTS OF THE PROPOSED TOTAL REVENUE BY RATE SCHEDULE?

A. The proposed total revenues by rate schedule with the corresponding allocated rates of return are summarized on Exhibit No. ___ (VP-4). Note that the allocated rates of return vary from the Company allowed rate of return as a whole, but they represent an acceptable level of allocated rate of return with corresponding revenue change for each customer group. Rate and revenue stability are among the considerations that allocated revenue requirements need not be strictly determined by equal rates of return. Rates do not have to follow rigid conformance to a specific allocated rate of return in a cost of service study. While equal rates of return serves as a point of reference, it is common to see the residential class with lower rates of return than the general service class. Setting higher proposed revenues for the large and interruptible customers warrants additional consideration because of their affect on total utility revenue with the opportunity cost decisions they can make related to their total business costs.

Q. HAVING ESTABLISHED THE PROPOSED TOTAL REVENUE FOR EACH CUSTOMER GROUP, WHAT METHODS OF REVENUE RECOVERY ARE PROPOSED?

A. The total proposed revenue for each rate is recovered through the fuel adjustment clause and the base rate tariff. Also, the allocated cost of service analysis provides additional information by providing the allocated revenue requirement in terms of the demand, energy, and customer components. CNO Witness Rogers has proposed a revised fuel adjustment clause, the principal revision being the recovery of a majority of the non fuel costs associated with ENO's allocated share of Grand Gulf Nuclear Station ("Grand Gulf") in base rates rather than through the fuel adjustment clause. Should the Council desire to recover these Grand Gulf costs from base rates rather than from the fuel adjustment clause and adopt CNO Witness Rogers recommendation of a revised FAC formula, I show the results in Exhibit No. ___ (VP-5). Revenue from this revised fuel adjustment clause was calculated for each customer group. The remainder of the allocated revenue requirement for each customer group will be recovered from revised base rate tariffs. The remaining cost of service to be recovered is expressed in terms of demand, energy and customer components. It is important to note that the total proposed revenues are based on the adjustments of CNO Witnesses Proctor, Mathai, and Vumbaco, and the proposed fuel adjustment clause revenue is based on the revised fuel adjustment clause proposed by CNO Witness Rogers. Should some of these adjustments or proposals not be accepted by the Council, the revised total allocated revenue, and revised adjustment clause revenue and base tariff revenues would be recalculated.

Q. PLEASE DESCRIBE THAT RECALCULATION IN MORE DETAIL.

A. Another set of proposed revenue by rate would be calculated for the approved adjustments. The allocated rates of return for each rate schedule would be varied to determine the corresponding total revenue changes for each customer group. Lower rates of return would be raised, and reasonable percentage changes to each rate schedule’s total revenue would be maintained. This process would be continued until the composite of these allocated revenues was equal to the total revenue requirement of the electric utility. Compared to the proposed revenue by rate based on the full set of adjustments of CNO Witnesses, this recalculation would result in a proportional change. It would maintain the same relative relationships among rates of return and percent changes from present revenue for the rate schedules.

Q. CAN YOU SUMMARIZE THE PROPOSED REVENUE IN TERMS OF ADJUSTMENT CLAUSE AND BASE RATE TARIFFS?

A. Yes, Exhibit No. ___ (VP-5) shows the proposed revenue by rate schedule, along with the proposed revenue recovered through the revised fuel adjustment clause and the proposed revenue recovered through base rate tariffs. The change and percent change in total bill are shown for each rate schedule. Additionally the demand, energy and customer related cost of service components are identified for both revenue recovery methods.

Q. DO YOU HAVE COST BASED PROPOSALS FOR REVISED ELECTRIC BASE TARIFFS?

A. Yes, Exhibit No. ___ (VP-6) summarizes the cost of service on a per kW, per kWh, and per bill basis for the proposed rates of each customer group. These per unit values were computed using the billing determinants filed for Period II. This detailed cost of service data by cost component is required for redesigning base tariffs. Since ENO fixed costs recovery are over $300 million, a current, equitable rate structure is just as important as the distribution of total revenue. The AIP required a complete rate design study along with its prerequisites, load research and cost of service studies. Although the load research and rate design studies were not completed, some recommendations can be made related to customer charge per bill, declining block rate structure, and seasonal rates

Q. WHAT DO YOU RECOMMEND FOR THE CUSTOMER CHARGE PER BILL?

A. The allocated customer cost of service per bill represents the basis for the customer charge per bill in the base rate tariff. But rate design principles place reasonable limits on the increased customer charge per bill above the existing rate Any remaining portions of customer cost of service not recovered in the customer charge would be recovered in the first rate block of the tariff. Specifically, with a residential customer related cost of service per bill of $14.00, and a current base rate tariff structured with a minimum bill of $8.00, I would recommend a customer charge of $10.00. The remainder of that portion of the cost of service would be recovered through the initial kWh usage. ENO proposed a change for the residential rate only, simply replacing the minimum bill with a customer charge of the same amount, with no reference to customer related cost of service.

Q. WHAT DO YOU RECOMMEND REGARDING THE DECLINING BLOCK RATE STRUCTURE?

A. Since no load research data is available to quantify cost analysis differences between low users and high users in each rate, I recommend that tariff structure changes should move toward a flat rate, and away from a declining block rate structure. Unless load research and cost data can definitely support a declining block structure, conservation policies have discouraged declining block rates.

Q. WHAT DO YOU RECOMMEND REGARDING SEASONAL RATES?

A. I recommend that the summer-winter seasonal differential should be expanded to all rate schedules except lighting rates. ENO is a definite summer peaking electric utility. The fixed and variable costs to serve all customers are higher in the summer months. Each rate's proposed annual revenue would be weighted proportionately more in summer months. The basis for the differential applied to the capacity costs of service is the ratio of the higher demand allocator values in the summer peak months relative to the lower demand allocator values in the winter months.

Q. HOW HAVE YOU INCORPORATED AN ALLOWANCE FOR FUNDING THE ENERGY SMART PLAN INTO THE ELECTRIC UTILITY COST ALLOCATION AND REVENUE REQUIREMENTS?

A. Should the Council desire to fund the ENO customer portion of the annual funds required for the Energy Smart Plan in the method detailed in the testimony of CNO Witness Vumbaco, I added the annual revenue and corresponding expense to the cost of service and added the amount to the proposed base revenue by rate schedule. These revenues by rate schedule are shown separate from the proposed revenue related to the cost of service. The corresponding expense of $3,056,852 was included as a separate administrative and general expense in the cost allocation. Exhibit Nos. ___ (VP-5) and ___(VP-6) show the addition of this system benefit charge to the proposed revenue requirement by rate schedule.

III. GAS OPERATIONS

Q. CAN YOU SUMMARIZE THE RESULTS OF THE FULLY ALLOCATED COST OF SERVICE ANALYSIS FOR THE GAS UTILITY?

A. The fully allocated cost of service analysis was developed for the projected year 2008, Period II, using CNO Witness Mathai's adjustments to the total cost of service and CNO Witness Proctor's recommended rate of return. Revenues for existing rates and the corresponding allocated rates of return of the gas utility are summarized in Exhibit No. ___ (VP-7).

Q. CAN YOU SUMMARIZE THE ALLOCATION METHODS USED IN THE ANALYSIS FOR THE GAS UTILITY?

A. Each item of the cost of service was analyzed to determine the appropriate method of allocation, while functionally grouping the costs as demand, commodity, and customer related. The demand related costs of gas supply, which included contracted capacity costs and storage costs were allocated on the basis of winter peak month or shoulder months as per contract terms. Demand related costs for the transmission/distribution system were allocated on the basis of 50 percent (50%) weighting for the peak month, and 50 percent (50%) weighting for the other winter peak season months. This allocation factor computation recognizes that while the winter peak is an important consideration in distribution, there are many other reliability and location-specific planning and operational considerations, somewhat similar to the electric distribution system. Furthermore weather station data indicates that the peak occurs in other winter months with a fifty percent (50%) probability. Weighting the remaining winter months in the distribution capacity allocation factor recognizes these other considerations. Commodity related costs were allocated on the basis of annual ccf sales. Customer related costs were allocated using the customer allocation factors developed by ENO.

Q. DID YOU MAKE ANY OTHER CHANGES TO THE GAS ALLOCATION FACTORS?

A. Yes. In the ENO cost allocation model, there was no provision for determining the allocated cost of service for the NJ customers, also classed as interruptibles. Twenty-three large customers are served at various locations in the service area from ENO's local distribution system and account for approximately twenty percent (20%) of the utility gas load. However, there is no substantial record of reduction or curtailment of these loads during peak conditions. As an alternative to ENO's present treatment of the NJ class of customer, I included those customers in the allocated cost of service analysis as a base load. NJ revenues included the cost of gas and the contracted total margin above that cost to offset the allocation of costs. Since no monthly ccf data was provided for NJ customers, the average ccf demand per month was used in developing allocation factors. In effect, by not using actual ccf in winter months for developing their allocation factor, this provides a reduction in their demand cost allocation. Without the NJ customers included in the cost allocation, the total margin of $960,000 changes the gas utility rate of return approximately seventy-five hundreds of a percent (0.75%). With the NJ customers included in the cost allocation, and assigning the total margin as revenue from that rate schedule, their allocated rate of return is close to the total utility (within one-half percent (0.5%) of total utility rate of return). This would imply that the total margin is roughly equivalent to the fixed costs of service for the NJ customers.

Q. ON WHAT BASIS DID YOU PROPOSE NEW TOTAL REVENUES FOR EACH GAS RATE SCHEDULE?

A. Similar to the process described above for the electric utility, I used the results of the allocated cost of service analysis, and varied the allocated rates of return for each rate schedule to determine the corresponding total revenue changes for each customer group. Lower rates of return were raised, and reasonable percent changes to each rate schedule's total revenue were maintained. This process was continued until the composite of these allocated revenues was equal to the allowed total revenue requirement of the gas utility.

Q. CAN YOU SUMMARIZE THE RESULTS OF THE PROPOSED TOTAL REVENUE BY RATE SCHEDULE FOR THE GAS UTILITY?

A. The proposed total revenues by rate schedule with the corresponding allocated rates of return are summarized in Exhibit No. ___(VP-8). While the allocated rates of return vary from the Company allowed rate of return as a whole, they represent an acceptable level of allocated rate of return with corresponding revenue change for each gas customer group. Setting higher proposed revenues for the NJ customers warrants additional consideration because of their affect on total utility revenue with the opportunity cost decisions they can make related to their total business costs.

Q. HAVING ESTABLISHED THE PROPOSED TOTAL REVENUE FOR EACH GAS CUSTOMER GROUP, WHAT METHODS OF REVENUE RECOVERY ARE PROPOSED?

A. The total proposed revenue for each rate is recovered through the purchased gas adjustment ("PGA") clause and the base tariff. Also, the allocated cost of service analysis provides additional information by providing the allocated revenue requirement in terms of the demand, commodity, and customer components. Revenue from the PGA clause was calculated for each customer group. The remainder of the allocated revenue requirement for each customer group will be recovered from revised base tariffs. The remaining cost of service to be recovered is expressed in terms of demand, energy and customer components. It is important to note that the total proposed revenues are based on the adjustments of CNO Witnesses Proctor and Mathai. Should some of these adjustments or proposals not be accepted, the revised total allocated revenue and base tariff revenues would have to be recalculated. The recalculation procedure would be the same as that described earlier in my testimony for the adjustments to the revenue requirement for the electric utility. Compared to the proposed revenue by rate based on the full set of adjustments of CNO witnesses, this recalculation would result in a proportional change. It would maintain the same relatives among rates of return and percent changes from present revenue for the rate schedules.

Q. CAN YOU SUMMARIZE THE PROPOSED GAS REVENUE FOR EACH CUSTOMER GROUP IN TERMS OF ADJUSTMENT CLAUSE AND BASE TARIFFS?

A. Yes, Exhibit No. ___ (VP-9) shows the proposed revenue by rate schedule, along with the proposed revenue recovered through the revised adjustment clause and the proposed revenue recovered through base tariffs. The percent change in the total bill for each rate schedule is also indicated. Additionally the demand, commodity and customer related cost of service components are identified for both revenue recovery methods.

Q. DO YOU HAVE COST BASED PROPOSALS FOR REVISED GAS BASE TARIFFS?

A. Yes, Exhibit No. ___ (VP-10) summarizes the cost of service on a per ccf, and per bill basis for the proposed rates of each customer group. These per unit values were computed using the billing determinants filed for Period II. The customer cost of service per bill represents the basis for customer charge per bill, notwithstanding the reasonable limits of an increase for that specific charge. Any remaining portions of customer cost of service not recovered in customer charge would be recovered in the first rate block of the tariff. Base tariff structure changes should be toward a flat rate, and away from a declining block rate structure. The winter-summer seasonal differential should be expanded to all rate schedules, reflecting the definite winter peak of the gas utility. A basis for the differential applied to the capacity costs of service is the ratio of the higher capacity contract basis in the winter peak months (85,000 MCF MDQ) relative to the lower capacity contract basis in the other months (approximately 30,000 MCF MDQ).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to amend or revise my testimony based on additional information that may become available before the hearing in this Docket.

AFFIRMATION

STATE OF COLORADO)
)
COUNTY OF DENVER)

I, Victor Prep, do hereby swear under penalty of perjury the following

That I am the person identified in the attached Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief, and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Victor Prep

Victor Prep

Subscribed and sworn to before me
this 17th day of November, 2008.

Charlotte De Cuir

NOTARY PUBLIC

CHARLOTTE DE CUIR
NOTARY PUBLIC
STATE OF COLORADO

My Commission Expires Nov. 13, 2012

EDUCATIONAL BACKGROUND AND EXPERIENCE
OF
VICTOR PREP

Mr. Prep graduated from the University of Oklahoma, Norman, Oklahoma, in 1966 with the degree of Bachelor of Science in Aerospace-Mechanical Engineering. In 1973, he received a Masters Degree in Business Administration from the Wharton School of Business, at the University of Pennsylvania, Philadelphia, Pennsylvania. He also graduated from the United States Naval Officer Nuclear Power Engineering Schools in Bainbridge, Maryland, Prototype Reactor Training School in Hartford, Connecticut, Inertial Navigation School in Norfolk, Virginia, and the United States Naval Submarine Service School at Groton, Connecticut. During his Naval Service, he received additional courses for Ships Engineer and Classified Material Control. Mr. Prep is a registered Professional Engineer in the Commonwealth of Pennsylvania.

In 2008, Mr. Prep became an Executive Consultant in the consulting firm of Legend Consulting Group Limited which provides consulting engineering, economic, financial and regulatory consulting services to the Council of the City of New Orleans in its regulation of Entergy New Orleans, Inc. and Energy Louisiana, LLC.

Since 1984 he has been an independent consultant and a successful entrepreneur who initiated and successfully ran several businesses, which he sold in 2008. In this capacity, he had complete control of all design, construction, and maintenance of physical plant, as well as business management for staff and operation. As an independent consultant, he supervised commercial/industrial projects with the Schuylkill County Economic Development Corporation and Schuylkill County Redevelopment Authority on co-generation, wind energy and other industrial projects. He served as Chairman of the Schuylkill County Redevelopment Authority from 2004 to 2008. He also served as a Principal Consultant with Management Applications Consulting of Reading, Pennsylvania providing management information services in the engineering, loss analysis, load management, and operations areas primarily for the utility/energy industry.

He also taught a college math course at the Pottstown School of Business, Pottstown, Pennsylvania.

From 1973 to 1984, he was Manager of Cost and Load Analysis in the Management Consulting Division of Gilbert Commonwealth, Reading, Pennsylvania. In that capacity, he conducted and presented extensive studies in regulatory issues including cost and load analyses, embedded cost allocation, rate design, load management and forecasting, revenue analysis, and preparation of and participation in utility rate cases including sponsorship of expert testimony. Major consulting projects included an Automated Rate Case Management System at Georgia Power Company and Southern California Edison Company; a week long industry seminar in Rate Case Preparation conducted for several years; and major Load Management research projects for EPRI and Western Farmers Electric Cooperative.

From 1971 to 1972, he was employed as a Field Startup Engineer with United Engineers and Constructors, Philadelphia, Pennsylvania. During that period, he worked on site at various utility power plant sites testing and starting new systems including Beezley's Point, Ocean City, New Jersey, Three Mile Island, Harrisburg, Pennsylvania, and Forney Burner Controls, Dallas, Texas.

From 1966 to 1971, he served as an Officer in the United States Navy Nuclear Submarine Force in Groton, Connecticut, with duties including Department Head of ship's Qualification for New Crew, Reactor Controls, Atmosphere Control Systems, Sonar, and Inertial Navigation, during several extended sea patrols and a shipyard repair period.

Mr. Prep has presented oral testimony before the Public Utilities Commission in the State of Texas on behalf of Central Power and Light Company concerning allocated cost of service and rate design. He has presented pre-filed written testimony before the Department of Public Utilities in the Commonwealth of Massachusetts on behalf of Fitchburg Gas and Electric and Commonwealth Energy Services Electric and Gas concerning allocated cost of service and cost basis for rate design. He has also presented written testimony before the Public Utilities Commission in the Commonwealth of Pennsylvania on behalf of UGI Luzerne Electric concerning allocated cost of service.

During the course of his career at Gilbert Commonwealth, Mr. Prep has prepared Cost and Rate Studies for the following Utilities:

Columbus and Southern, Columbus, Ohio
Fitchburg Gas and Electric, Fitchburg, Massachusetts
Exeter and Hampton Electric Utility, Exeter, New Hampshire
Concord Electric Company, Concord, New Hampshire
Green Mountain Power, Burlington, Vermont
Bangor Hydro Electric, Bangor, Maine
UGI Gas Company, Reading Pennsylvania
UGI Luzerne Electric, Wilkes Barre, Pennsylvania
Shaeffer Brewing Company, Water System Cost of Service
City of Lansing Electric Utility, Lansing Michigan
City of Vineland, Electric Utility, Vineland, New Jersey
City of Lakeland, Department of Electric & Water, Lakeland Florida
Wisconsin Electric Power Company, Madison, Wisconsin
Madison Gas and Electric, Madison, Wisconsin
Georgia Power Company, Atlanta, Georgia,
Central Power and Light Company, Corpus Christi, Texas
Lower Colorado River Authority, Austin, Texas
Southern California Edison, Pasadena, California
Rate Case Preparation Seminars – Dallas, Hershey, Atlanta

Berkshire Gas Company, Pittsfield, Massachusetts
Commonwealth Energy Services Electric and Gas, Cambridge, Massachusetts
Central Illinois Public Service, Springfield, Illinois
Hartford Steam Company, Hartford, Connecticut
Iowa-Illinois Gas and Electric, Davenport, Iowa
Indiana Gas Company, Evansville, Indiana
Iowa Power and Light, Des Moines, Iowa
Philadelphia Gas Works, Philadelphia, Pennsylvania
Toledo Edison Company, Toledo, Ohio
Nova Scotia Power Company, Halifax, Nova Scotia
Western Farmers Electric Cooperative, Anadarko, Oklahoma, Load Management
EPRI Industry Study on Residential Water Heater Loads, Load Management

Exhibit No. ___ (VP-3)
Docket No. UD-08-03

Summary of Results- Present Rates ($000)	TOTAL ELECTRIC	RES	MMA	SMALL ELEC SVC	MB
ENO's Cost Allocation as Filed Using Present Rates					
1 EARNED RATE OF RETURN ON RATE BASE	10.99%	3.08%	20.86%	11.99%	14.48%
ENO's Cost Allocation as Filed Using ENO's Proposed Reduction of $18.209 Million					
2 EARNED RATE OF RETURN ON RATE BASE	8.78%	1.82%	18.21%	10.27%	12.22%
Recommended Cost Allocation Using Present Rates					
3 TOTAL RATE BASE	269,939	142,933	715	46,423	2,412
PROPOSED REVENUES					
4 TOTAL RATE SCHEDULE REVENUES	449,549	163,736	1,417	65,533	3,875
5 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	182,155	14,160	134	5,577	336
6 TOTAL REVENUES	631,703	177,896	1,551	71,110	4,211
7 TOTAL OPERATING EXPENSES	569,394	164,936	1,414	61,302	3,630
8 TOTAL OPERATING INCOME	62,309	12,960	137	9,808	581
9 EARNED RATE OF RETURN ON RATE BASE	23.08%	9.07%	19.17%	21.13%	24.10%

Summary of Results- Present Rates ($000)	LG ELEC SVC	LG ELEC HLF	MMGS	HV	EIS
ENO's Cost Allocation as Filed Using Present Rates					
1 EARNED RATE OF RETURN ON RATE BASE	24.31%	25.37%	19.13%	147.93%	84.29%
ENO's Cost Allocation as Filed Using ENO's Proposed Reduction of $18.209 Million					
2 EARNED RATE OF RETURN ON RATE BASE	20.57%	20.58%	15.44%	123.87%	52.26%
Recommended Cost Allocation Using Present Rates					
3 TOTAL RATE BASE	26,722	36,918	2,911	412	52
PROPOSED REVENUES					
4 TOTAL RATE SCHEDULE REVENUES	64,783	105,084	6,421	13,829	1,105
5 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	5,622	8,977	557	1,260	87
6 TOTAL REVENUES	70,405	114,060	6,978	15,089	1,192
7 TOTAL OPERATING EXPENSES	59,063	94,780	5,975	12,347	893
8 TOTAL OPERATING INCOME	11,342	19,280	1,003	2,742	299
9 EARNED RATE OF RETURN ON RATE BASE	42.45%	52.22%	34.46%	665.54%	572.46%

Summary of Results- Present Rates
($000)

	LIS	ODSL	ONW	SL	Sales for Resale	TS
ENO's Cost Allocation as Filed Using Present Rates						
1 EARNED RATE OF RETURN ON RATE BASE	99.56%	(6.85%)	(5.27%)	26.98%	NA	(10.50%)
ENO's Cost Allocation as Filed Using ENO's Proposed Reduction of $18.209 Million						
2 EARNED RATE OF RETURN ON RATE BASE	87.71%	-6.95%	-5.35%	24.34%	NA	-11.51%
Recommended Cost Allocation Using Present Rates						
3 TOTAL RATE BASE	989	5,962	149	3,156	0	185
PROPOSED REVENUES						
4 TOTAL RATE SCHEDULE REVENUES	15,975	2,359	66	5,239	0	129
5 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	1,477	108	4	278	143,558	19
6 TOTAL REVENUES	17,452	2,466	70	5,517	143,558	148
7 TOTAL OPERATING EXPENSES	15,349	2,425	65	3,878	143,559	154
8 TOTAL OPERATING INCOME	2,103	42	5	1,638	(1)	(5)
9 EARNED RATE OF RETURN ON RATE BASE	212.70%	0.70%	3.27%	51.90%	0.00%	(2.95%)

Exhibit No. ___ (VP-4)
Docket No. UD-08-03

Summary of Results- Proposed ($000)	TOTAL ELECTRIC	RES	MMA	SMALL ELEC SVC	MB
1 TOTAL RATE BASE	269,939	142,933	715	46,423	2,412
PROPOSED REVENUES					
2 TOTAL RATE SCHEDULE REVENUES	385,335	152,400	1,300	56,000	3,300
3 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	182,155	14,460	136	5,573	336
4 TOTAL REVENUES	567,490	166,860	1,436	61,573	3,636
5 TOTAL OPERATING EXPENSES	544,686	160,744	1,370	57,631	3,408
6 TOTAL OPERATING INCOME (L4 - L5)	22,803	6,116	66	3,941	228
7 EARNED RATE OF RETURN ON RATE BASE (L6 / L1)	8.45%	4.28%	9.24%	8.49%	9.43%
REVENUE REQUIREMENT -EQUAL RATES OF RETURN					
8 PROPOSED RATE OF RETURN (11.75% ROE)	8.45%	8.45%	8.45%	8.45%	8.45%
9 REQUIRED OPERATING INCOME (L1 * L8)	22,810	12,078	60	3,923	204
10 OPERATING INCOME DEFICIENCY (EXCESS) (L9 - L6)	6	5,962	(6)	(18)	(24)
11 REVENUE CONVERSION FACTOR		1.642542	1.625511	1.629659	1.625422
12 REVENUE DEFICIENCY (EXCESS) (L10 * L11)	726	9,793	(9)	(30)	(39)
13 RATE SCHEDULE REVENUE REQUIREMENT (L2 + L12) TOTAL = BASE TARIFF + FAC	386,061	162,193	1,291	55,970	3,261

Summary of Results- Proposed ($000)	LG ELEC SVC	LG ELEC HLF	MMGS	HV	EIS
1 TOTAL RATE BASE	26,722	36,918	2,911	412	52
PROPOSED REVENUES					
2 TOTAL RATE SCHEDULE REVENUES	53,000	85,000	5,000	9,600	665
3 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	5,559	8,850	545	1,204	80
4 TOTAL REVENUES	58,559	93,850	5,545	10,804	745
5 TOTAL OPERATING EXPENSES	54,494	86,981	5,421	10,688	720
6 TOTAL OPERATING INCOME (L4 - L5)	4,066	6,869	123	116	25
7 EARNED RATE OF RETURN ON RATE BASE (L6 / L1)	15.21%	18.61%	4.24%	28.08%	48.41%
REVENUE REQUIREMENT -EQUAL RATES OF RETURN					
8 PROPOSED RATE OF RETURN (11.75% ROE)	8.45%	8.45%	8.45%	8.45%	8.45%
9 REQUIRED OPERATING INCOME (L1 * L8)	2,258	3,120	246	35	4
10 OPERATING INCOME DEFICIENCY (EXCESS) (L9 - L6)	(1,808)	(3,749)	123	(81)	(21)
11 REVENUE CONVERSION FACTOR	1.626441	1.625613	1.638216	1.625422	1.625422
12 REVENUE DEFICIENCY (EXCESS) (L10 * L11)	(2,940)	(6,095)	201	(131)	(34)
13 RATE SCHEDULE REVENUE REQUIREMENT (L2 + L12) TOTAL = BASE TARIFF + FAC	50,060	78,905	5,201	9,469	631

Summary of Results- Proposed ($000)

	LIS	ODSL	ONW	SL	SALES FOR RESALE	TS
1 TOTAL RATE BASE	989	5,962	149	3,156	0	185
PROPOSED REVENUES						
2 TOTAL RATE SCHEDULE REVENUES	12,900	2,500	70	3,450	0	150
3 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	1,457	120	5	252	143,558	20
4 TOTAL REVENUES	14,357	2,620	75	3,702	143,558	170
5 TOTAL OPERATING EXPENSES	14,155	2,486	67	3,175	143,559	162
6 TOTAL OPERATING INCOME (L4 - L5)	203	134	8	526	(1)	8
7 EARNED RATE OF RETURN ON RATE BASE (L6 / L1)	20.51%	2.24%	5.21%	16.67%	0.00%	4.40%
REVENUE REQUIREMENT -EQUAL RATES OF RETURN						
8 PROPOSED RATE OF RETURN (11.75% ROE)	8.45%	8.45%	8.45%	8.45%	8.45%	8.45%
9 REQUIRED OPERATING INCOME (L1 * L8)	84	504	13	267	0	16
10 OPERATING INCOME DEFICIENCY (EXCESS) (L9 - L6)	(119)	370	5	(260)	1	7
11 REVENUE CONVERSION FACTOR	1.625422	1.632238	1.634845	1.625422	1.625422	1.625422
12 REVENUE DEFICIENCY (EXCESS) (L10 * L11)	(194)	604	8	(422)	2	12
13 RATE SCHEDULE REVENUE REQUIREMENT (L2 + L12) TOTAL = BASE TARIFF + FAC	12,706	3,104	78	3,028	2	162

Exhibit No. ___ (VP-5)
Docket No. UD-08-03

Proposed Revenue Recovery by BaseTariff & Adjust Clause
($000's)

		TOTAL ELECTRIC	RES	MMA	SMALL ELEC SVC	MB
1	TOTAL RATE SCHEDULE REVENUES PRESENT	449,549	163,736	1,417	65,533	3,875
2	TOTAL RATE SCHEDULE REVENUES - PROPOSED	383,020	149,500	1,350	56,000	3,300
3	CHANGE IN TOTAL REVENUE BY RATE SCHEDULE	(66,529)	(14,236)	(67)	(9,533)	(575)
4	% CHANGE IN TOTAL BILL	-14.80%	-8.69%	-4.71%	-14.55%	-14.83%
	PROPOSED REVENUE FROM FAC					
5	PROPOSED FAC	174,871	58,912	532	23,256	1,456
6	Energy Related	127,872	48,268	561	18,699	1,123
7	Demand Related	46,999	10,644	(29)	4,557	333
	PROPOSED REVENUE FROM BASE TARIFF					
8	PROPOSED BASE	208,149	90,588	818	32,744	1,844
9	Energy Related	67,424	22261	202	8974	564
10	Demand Related	140,725	68,327	616	23,770	1,280

Proposed Revenue Recovery by BaseTariff & Adjust Clause
($000's)

		LG ELEC SVC	LG ELEC HLF	MMGS	HV	EIS
1	TOTAL RATE SCHEDULE REVENUES PRESENT	64,783	105,084	6,421	13,829	1,105
2	TOTAL RATE SCHEDULE REVENUES - PROPOSED	53,000	85,000	5,000	9,850	680
3	CHANGE IN TOTAL REVENUE BY RATE SCHEDULE	(11,783)	(20,084)	(1,421)	(3,979)	(425)
4	% CHANGE IN TOTAL BILL	-18.19%	-19.11%	-22.13%	-28.77%	-38.44%
	PROPOSED REVENUE FROM FAC					
5	PROPOSED FAC	25,491	44,304	2,584	6,087	585
6	Energy Related	19,077	29,378	1,862	4,012	227
7	Demand Related	6,414	14,926	722	2,075	358
	PROPOSED REVENUE FROM BASE TARIFF					
8	PROPOSED BASE	27,509	40,696	2,416	3,763	95
9	Energy Related	9963	17206	1028	2415	173
10	Demand Related	17,546	23,490	1,388	1,348	(78)

Proposed Revenue Recovery by BaseTariff & Adjust Clause
($000's)

		LIS	ODSL	ONW	SL	SALES FOR RESALE	TS
1	TOTAL RATE SCHEDULE REVENUES PRESENT	15,975	2,359	66	5,239	0	129
2	TOTAL RATE SCHEDULE REVENUES - PROPOSED	13,170	2,500	70	3,450	0	150
3	CHANGE IN TOTAL REVENUE BY RATE SCHEDULE	(2,805)	141	4	(1,789)	0	21
4	% CHANGE IN TOTAL BILL	-17.56%	5.99%	6.79%	-34.15%	0.00%	16.60%
	PROPOSED REVENUE FROM FAC						
5	PROPOSED FAC	9,264	512	13	1,830	0	45
6	Energy Related	4,041	115	3	480	0	26
7	Demand Related	5,223	397	10	1,350	0	19
	PROPOSED REVENUE FROM BASE TARIFF						
8	PROPOSED BASE	3,906	1,988	57	1,620	0	105
9	Energy Related	3671	204	5	740	0	18
10	Demand Related	235	1,784	52	880	0	87

Exhibit No. ___ (VP-6)
Docket No. UD-08-03

Cost of Service on Per Unit Basis- Proposed Rates
($000's)

	TOTAL ELECTRIC	RES	MMA	SMALL ELEC SVC	MB
UNIT COSTS OF SERVICE ANALYSIS					
UNIT COSTS OF SERVICE - DEMAND RELATED					
1 $ PRODUCTION DEMAND	182,991	40,693	472	15,743	945
2 $ TRANSMISSION DEMAND	14,982	5,997	61	2,186	128
3 $ DISTRIBUTION DEMAND	40,732	7,490	170	6,215	498
4 $ LABOR RELATED DEMAND	34,014	13,378	130	5,461	309
5 TOTAL DEMAND RELATED COST OF SERVICE	272,719	67,557	832	29,604	1,880
BILLING DATA	225,720				
6 DEMAND - MW		N/A	58	2,643	N/A
7 ENERGY - MWH		1,542,384	N/A	N/A	39,086
DEMAND RELATED COST OF SERVICE PER UNIT					
8 $/kW		N/A	14.23	11.20	N/A
9 $/kWH		0.04380	N/A	N/A	0.04810
UNIT COSTS OF SERVICE - ENERGY RELATED					
10 $ TOTAL ENERGY RELATED COST OF SERVICE	254,300	56,053	509	22,750	1,435
11 ENERGY SMART PLAN	3,057	1,542	8	590	23
BILLING DATA					
12 ENERGY - MWH		1,542,384	14,097	621,780	39,086
13 ENERGY RELATED COST OF SERVICE PER kWh $/kWH		0.03734	0.03669	0.03754	0.03728
UNIT COSTS OF SERVICE - CUSTOMER RELATED					
14 TOTAL CUSTOMER RELATED COST OF SERVICE	38,155	21,850	16	5,669	161
15 BILLING DATA - TOTAL BILLS		1,570,548	96	175,215	3,528
16 CUSTOMER RELATED COST OF SERVICE PER BILL		13.91	165.50	32.35	45.69

Cost of Service on Per Unit Basis- Proposed Rates
($000's)

	LG ELEC SVC	LG ELEC HLF	MMGS	HV	EIS
UNIT COSTS OF SERVICE ANALYSIS					
UNIT COSTS OF SERVICE - DEMAND RELATED					
1 $ PRODUCTION DEMAND	16,053	24,721	1,567	3,376	191
2 $ TRANSMISSION DEMAND	2,082	3,180	205	408	33
3 $ DISTRIBUTION DEMAND	5,476	17,605	860	340	273
4 $ LABOR RELATED DEMAND	4,608	7,016	434	780	51
5 TOTAL DEMAND RELATED COST OF SERVICE	28,219	52,522	3,065	4,903	548
BILLING DATA					
6 DEMAND - MW	1,933	2,482	167	312	76
7 ENERGY - MWH	N/A	N/A	N/A	N/A	N/A
DEMAND RELATED COST OF SERVICE PER UNIT					
8 $/kW	14.60	21.16	18.41	15.69	7.21
9 $/kWH	N/A	N/A	N/A	N/A	N/A
UNIT COSTS OF SERVICE - ENERGY RELATED					
10 $ TOTAL ENERGY RELATED COST OF SERVICE	25,385	43,856	2,595	6,108	440
11 ENERGY SMART PLAN	458	374	5	2	2
BILLING DATA					
12 ENERGY - MWH	690,914	1,196,629	71,217	180,032	12,901
13 ENERGY RELATED COST OF SERVICE PER kWh $/kWH	0.03740	0.03696	0.03651	0.03394	0.03430
UNIT COSTS OF SERVICE - CUSTOMER RELATED					
14 TOTAL CUSTOMER RELATED COST OF SERVICE	5,849	776	86	2,044	5
15 BILLING DATA - TOTAL BILLS	6,588	3,420	120	24	12
16 CUSTOMER RELATED COST OF SERVICE PER BILL	887.78	226.99	719.00	85,173.20	457.46

Cost of Service on Per Unit Basis- Proposed Rates
($000's)

	LIS	ODSL	ONW	SL	SALES FOR RESALE	TS	
UNIT COSTS OF SERVICE ANALYSIS							
UNIT COSTS OF SERVICE - DEMAND RELATED							
1 $ PRODUCTION DEMAND	3,401	97	2	404	75,305	22	22
2 $ TRANSMISSION DEMAND	583	49	1	66	0	5	5
3 $ DISTRIBUTION DEMAND	489	(264)	(23)	1,590	0	13	13
4 $ LABOR RELATED DEMAND	907	689	16	222	0	14	14
5 TOTAL DEMAND RELATED COST OF SERVICE	5,379	571	(3)	2,282	75,305	53	53
BILLING DATA							
6 DEMAND - MW	486	N/A	N/A	N/A	N/A	N/A	
7 ENERGY - MWH	N/A	14,137	363	51,276	N/A	1,232	N/A
DEMAND RELATED COST OF SERVICE PER UNIT							1,232
8 $/kW	11.07	N/A	N/A	N/A	N/A	N/A	
9 $/kWH	N/A	0.04040	(0.00842)	0.04451	N/A	0.04326	N/A
							0.04326
UNIT COSTS OF SERVICE - ENERGY RELATED							
10 $ TOTAL ENERGY RELATED COST OF SERVICE	9,286	520	13	1,903	83,403	45	
11 ENERGY SMART PLAN	36	2	12	0	N/A	1	45
BILLING DATA							
12 ENERGY - MWH	273,691	14,137	363	51,276	N/A	1,232	1,232
13 ENERGY RELATED COST OF SERVICE PER kWh	0.03406	0.03694	0.07014	0.03711	N/A	0.03738	
$/kWH							0.03638
UNIT COSTS OF SERVICE - CUSTOMER RELATED							
14 TOTAL CUSTOMER RELATED COST OF SERVICE	1,123	450	37	58	N/A	30	30
15 BILLING DATA - TOTAL BILLS	12	3,192	292	24	N/A	4,464	4,464
16 CUSTOMER RELATED COST OF SERVICE PER BILL	93,582.10	140.93	125.60	2,428.34	N/A	6.74	6.74

Exhibit No. ___ (VP-7)
Docket No. UD-08-03

Summary of Results- Present Rates
($000)

	TOTAL GAS	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SVC	NON-JURISDICTIONAL	MUNI	LARGE MUNI
ENO's Cost Allocation as Filed Using Present Rates							
1 EARNED RATE OF RETURN ON RATE BASE	1.65%	-2.57%	17.82%	17.92%	NA	0.78%	-4.85%
ENO's Cost Allocation as Filed Using ENO's Proposed Increase of $8.449 Million							
2 EARNED RATE OF RETURN ON RATE BASE	8.78%	1.17%	18.86%	18.90%		3.15%	-1.07%
Recommended Cost Allocation Using Present Rates							
3 TOTAL RATE BASE	70,825	45,663	7,660	6,211	6,193	653	4,445
PROPOSED REVENUES							
4 TOTAL RATE SCHEDULE REVENUES	133,650	54,487	17,617	22,281	23,787	912	14,566
5 TOTAL ENTERGY/SYSTEM/OTHER OPER REV	1,501	683	190	227	240	11	150
6 TOTAL REVENUES	135,151	55,170	17,807	22,508	24,027	923	14,716
7 TOTAL OPERATING EXPENSES	131,295	54,551	15,916	20,803	23,967	891	15,167
8 TOTAL OPERATING INCOME	3,856	619	1,891	1,704	60	32	(451)
9 EARNED RATE OF RETURN ON RATE BASE	5.44%	1.36%	24.69%	27.44%	0.97%	4.95%	-10.15%

Exhibit No. ___ (VP-8)
Docket No. UD-08-03

Summary of Results- Proposed
($000)

		TOTAL GAS	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SVC	NON-JURISDICTIONAL	MUNI	LARGE MUNI
1	TOTAL RATE BASE ADJUSTED	70,825	45,663	7,660	6,211	6,193	653	4,445
	REVENUES							
2	TOTAL RATE SCHEDULE REVENUES ADJUSTED	136,687	57,500	17,020	21,480	24,267	970	15,450
3	TOTAL OTHER REVENUES ADJUSTED	1,501	698	181	215	240	11	155
4	TOTAL REVENUES ADJUSTED (L2 + L3)	138,188	58,198	17,201	21,695	24,507	981	15,605
5	TOTAL OPERATING EXPENSES ADJUSTED	132,464	55,770	15,653	20,451	24,150	914	15,526
6	TOTAL OPERATING INCOME ADJUSTED (L4 - L5)	5,725	2,428	1,549	1,244	357	67	79
7	EARNED RATE OF RETURN ON RATE BASE (L6 / L1)	8.08%	5.32%	20.22%	20.03%	5.76%	10.23%	1.78%
	REVENUE REQUIREMENT							
8	REQUIRED RATE OF RETURN	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
9	REQUIRED OPERATING INCOME (L1 * L8)	5,723	3,690	619	502	500	53	359
10	OPERATING INCOME DEFICIENCY (L9 - L6)	(2)	1,261	(930)	(742)	143	(14)	280
11	REVENUE CONVERSION FACTOR		1.6401	1.6279	1.6260	1.6254	1.6254	1.6254
12	REVENUE DEFICIENCY / (EXCESS) (L10 * L11)	14	2,069	(1,514)	(1,207)	233	(23)	455

Exhibit No. ___ (VP-9)
Docket No. UD-08-03

Proposed Revenue Recovery by BaseTariff & Adjst Clause
($000)

	TOTAL GAS	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SVC	NON-JURISDICTIONAL	MUNI	LARGE MUNI
1 TOTAL RATE SCHEDULE REVENUES PRESENT	134,130	54,487	17,617	22,281	24,267	912	14,566
2 TOTAL RATE SCHEDULE REVENUES - PROPOSED BY RATE	136,687	57,500	17,020	21,480	24,267	970	15,450
3 CHANGE IN TOTAL REVENUE BY RATE SCHEDULE	2,557	3,013	-597	-801	0	58	884
4 % CHANGE IN TOTAL BILL	1.91%	5.53%	-3.39%	-3.60%	0.00%	6.31%	6.07%
PROPOSED REVENUE FROM PGA CLAUSE BY RATE SCHED							
5 PGA	96,327	34,257	11,672	16,977	20,000	627	12,794
6 Energy Related	80,079	26,540	9,511	13,930	18,311	475	11,312
7 Demand Related	18,248	7,717	2,161	3,047	3,689	152	1,482
PROPOSED REVENUE FROM BASE TARIFF BY RATE SCHED							
8 BASE	38,360	23,243	5,348	4,503	2,267	343	2,656
9 Energy Related	0	0	0	0	0	0	0
10 Demand Related	24,822	11,144	4,311	4,355	2,139	272	2,598
11 Customer Related	13,537	12,098	1,036	147	128	70	58

Exhibit No. ___ (VP-10)
Docket No. UD-08-03

Cost of Service on Per Unit basis- Proposed Rates
($000)

	TOTAL GAS	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SVC	NON-JURISDICTIONAL	MUNI	LARGE MUNI
UNIT COSTS OF SERVICE - DEMAND RELATED							
1 $ GAS SUPPLY DEMAND COSTS	13,600	6,598	1,516	2,063	1,815	125	1,483
2 $ TRANSMISSION DEMAND COSTS	324	163	35	46	44	3	34
3 $ DISTRIBUTION DEMAND COSTS	14,068	6,847	1,563	1,983	2,050	126	1,499
4 $ LABOR RELATED DEMAND COSTS	15,076	8,212	1,745	1,797	1,847	148	1,327
5 TOTAL DEMAND RELATED COST OF SERVICE	43,069	21,820	4,859	5,889	5,757	402	4,342
6 BILLING DATA - CCF BY RATE SCHEDULE	10,211,353	3,384,287	1,212,830	1,776,276	2,334,960	60,600	1,442,400
7 DEMAND RELATED COST OF SERVICE PER CCF	$4.2178	$6.4476	$4.0067	$3.3153	$2.4654	$6.6349	$3.0104
UNIT COSTS OF SERVICE - COMMODITY RELATED							
8 $ TOTAL COMMODITY RELATED COST OF SERVICE	80,079	26,540	9,511	13,930	18,311	475	11,312
9 BILLING DATA - CCF BY RATE SCHEDULE	10,211,353	3,384,287	1,212,830	1,776,276	2,334,960	60,600	1,442,400
10 COMMODITY RELATED COST OF SERVICE PER CCF	$7.8422	$7.8422	$7.8422	$7.8422	$7.8422	$7.8422	$7.8422
UNIT COSTS OF SERVICE - CUSTOMER RELATED							
11 TOTAL CUSTOMER RELATED COST OF SERVICE	13,537	12,098	1,036	147	128	70	58
12 BILLING DATA - TOTAL BILLS	1,179,132	1,111,068	63,468	1,032	1,032	2,520	12
13 CUSTOMER RELATED COST OF SERVICE PER BILL	$11.48	$10.89	$16.33	$142.54	$123.82	$27.85	$4,831.49

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	**)))))**	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-6

Question:

Referencing page 17, lines 6-12 of Mr. Prep's testimony:

a. Please identify other utility regulatory jurisdictions of which Mr. Prep is aware that require that costs recovered through fuel adjustment clauses and/or purchased gas adjustment clauses be included in a cost of service study for purposes of utility rate setting. For each jurisdiction so identified, please include references to specific rules or orders establishing such a policy.

b. Please identify other utility regulatory jurisdictions of which Mr. Prep is aware that require that costs recovered through riders outside of base rates (other than fuel adjustment clauses and/or purchased gas adjustment clauses) be included in a cost of service study for purposes of utility rate setting. For each jurisdiction so identified, please include references to specific rules or orders establishing such a policy.

Response:

a. Refer to the following utility industry references, included in Advisors' response to ENO 1-1, V_Prep Workpapers, which discuss that total utility costs be included in the cost of service allocation:
NARUC Cost Allocation Manual – (extracts provided in workpaper file)
NARUC Rate Design Cost Allocation – (extracts provided)
NRRI Cost Allocation and Rate Design Training (OCC) 2017 – (extracts provided)
CPUC Rate Case Manual 2017 – (extracts provided in workpaper file)

b. Refer to part a.

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	))))))	**CAUSE NO. PUD 201700496**

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OF OKLAHOMA

GREAT SEAL OF THE STATE OF OKLAHOMA
1907

RESPONSIVE TESTIMONY OF

GEOFFREY M. RUSH

MAY 2, 2018

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

RESPONSIVE TESTIMONY

OF

GEOFFREY M. RUSH

MAY 2, 2018

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INTRODUCTION

Q: Please state your name and your business address.

A: My name is Geoffrey M. Rush. My business address is Oklahoma Corporation Commission, Public Utility Division, Jim Thorpe Office Building, Room 580, 2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105.

Q: Have you previously testified before the Oklahoma Corporation Commission ("OCC" or "Commission") and were your qualifications accepted?

A: Yes. I have previously testified before this Commission, and my credentials were accepted at that time.

Q: Who employs you and what is your position?

A: I am employed as a Public Utility Energy Coordinator by the Public Utility Division ("PUD") of the OCC.

Q: How long have you been so employed?

A: I have been employed by the Commission since March 2013.

Q: What are your duties and responsibilities with PUD?

A: As an Energy Coordinator, I am the direct supervisor for a team of PUD analysts that, as authorized by the State of Oklahoma, regulate electric and gas transmission rates, terms, conditions of service, and safety, that are in Oklahoma's public interest, and as a surrogate for competition, provides rates that are fair, just, and reasonable. For a complete list of my work history and educational background, please review my attached curriculum vitae.[1]

In addition, I conduct research and perform comparative analysis of utility applications, reports, financial records, exhibits, and workpapers to ensure PUD makes accurate recommendations. My work also focuses on PUD's involvement with Southwest Power Pool ("SPP") in the areas of Settlements, the Integrated Marketplace ("IM"), and the processes relating to the Day-Ahead Market ("DAM").[2] I monitor SPP Working Groups and Task Forces, which include the Market Working Group, Change Working Group, Settlement User Group, Export Pricing Task Force, and the Z2 Task Force. Previously, I worked with SPP during the test markets and the transmission rights market development. From June 2014 to December 2014, I was also a voting member of SPP's Mitigated Offer Task Force.

[1] Exhibit GMR – 1.
[2] SPP is one of nine Independent System Operators/Regional Transmission Organizations, and one of eight North American Electric Reliability Corporation regional entities. SPP is mandated by the Federal Energy Regulatory Commission ("FERC") to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices for electricity.

PURPOSE

Q: What is the purpose of this Responsive Testimony regarding the Application filed by Oklahoma Gas and Electric Company ("OG&E" or "Company") for an Order of the Commission authorizing Applicant to modify its rates, charges, and tariffs for retail electric service in Oklahoma as filed in Cause No. PUD 201700496?

A: The purpose of this Responsive Testimony is to detail the areas that PUD reviewed, as well as its review process. In addition, the purpose of this Responsive Testimony is to present PUD's recommendation in this Cause regarding the following areas:

(1) Return on Equity ("ROE");
(2) Cost of Debt and Capital Structure;
(3) Short-Term Incentive Compensation ("STI");
(4) Long-Term Incentive Compensation ("LTI");
(5) Payroll Expense;
(6) Amortization of Pension Regulatory Liability;
(7) Materials and Supplies;
(8) Adjust Coal & Oil to reflect 13 month average;
(9) Adjust Gas in Storage to reflect 13 month average;
(10) Fuels and Purchased Power Expenses Removal;
(11) Unbilled Revenues and Over/Under Recoveries;
(12) Prepayments Expense;
(13) Outside Services/Attorney Fees;
(14) Rate Case Expense; and
(15) Regulatory Expense

In addition, PUD reviewed the areas of Day-Ahead Pricing, Pension/Post Retirement Benefits, Directors' Fees & Executive Salaries, Executive Salary Surveys, Wage and Salary Surveys, and Payroll Distribution.

EXECUTIVE SUMMARY

On January 16, 2018, Oklahoma Gas and Electric ("OG&E" or "Company") filed its Application for an adjustment in its rates, charges, and tariffs for retail electric service in Oklahoma. The Public Utility Division ("PUD") reviewed the Application, testimony of Company witnesses, and Company workpapers. PUD also interviewed Company personnel regarding various areas of assignment and conducted onsite audits to review confidential information at the Company's corporate office in Oklahoma City, Oklahoma. Items specifically covered in this Responsive Testimony are as follows: Return on Equity ("ROE"), Cost of Debt and Capital Structure, Short-Term Incentive Compensation ("STI"), Long-Term Incentive Compensation ("LTI"), Payroll Expense, Amortization of Pension Regulatory Liability, Materials and Supplies, Adjust Coal & Oil to reflect 13 month average, Adjust Gas in Storage to reflect 13 month average, Fuels and Purchased Power Expenses, Unbilled Revenues and Over/Under Recoveries, Prepayments Expense, Outside Services/Attorney Fees, Rate Case Expense and Regulatory Expense. Additionally, this Responsive Testimony will list all of the areas that PUD reviewed.

OG&E's cost of capital is comprised of two components: debt and equity. Fixed, contractual interest payments determine the cost of debt, while the cost of equity must be estimated through financial models and other analyses. PUD employed three financial models on a group of similar proxy companies to arrive at an estimate of the Company's cost of equity in this Cause, including (1) the Discounted Cash Flow Model ("DCF"); (2) the Capital Asset Pricing Model ("CAPM"); and (3) the Comparable Earnings ("CE") Model. In addition, PUD added a market analysis to review the return of utility fund companies compared to the market as a whole. Finally, PUD conducted an analysis to determine the Company's optimal capital structure.

The DCF Model is based on a fundamental financial model called the dividend discount model, which maintains that the value of a security is equal to the present value of the future cash flows that it generates. The average DCF result for the proxy companies using the Quarterly Approximation DCF model is 9.84%. The CAPM is a market-based model where investors require higher returns for adding additional risk. The average CAPM result for the proxy companies is 6.65%. The CE Model involves averaging the earned returns on other utility companies. The composite average and result of the CE Model is 9.84%. The market analysis looked at fourteen of the top utility funds, as well as the seventeen proxy group companies, and compared the returns over a 3-year, 5-year, and 10-year time span. The average market analysis result, using the 10-year time span of the seventeen proxy companies, is 8.62%. PUD's recommended ROE is 8.75%, which represents the midpoint, rounded to the nearest quarter percent, in a range of reasonableness as determined by PUD.

Capital Structure refers to the way a firm finances its overall operations through external debt and equity capital. PUD recommends the Company's proposed debt to equity ratio of 46.7% debt and 53.3% equity.

The Company has requested $17,973,228 in STI Compensation. PUD recommends that the Commission allow full recovery of STI. PUD believes that STI is appropriate to include in the overall compensation package of OG&E and recommends full allowance of its cost recovery from customers. PUD believes that short-term incentives are an important way for OG&E to attract and retain qualified employees. In addition, because the Company's incentive compensation package is not directly tied to financial performance, there is no "trigger" which, if met, would provide incentive payout. Focusing on the entire incentive package benefits both ratepayers and shareholders, as employees are focused on creating a company which is not only financially sound and strong, but also one that is safe, reliable, and has efficient infrastructure in place.

PUD recommends the Company's proposed removal of LTI Compensation in the amount of $5,487,519.

PUD recommends the Company's proposed amortization of the Pension Regulatory Liability in the amount of $44,020,103 and with the proposed amortization period of five years, results in a reduction to expenses (i.e., a credit to customers) in the amount of $8,804,003.

PUD recommends the Commission accept OG&E's Adjustment No. 1, removing the over-recovery of fuel and rider collections, decreasing revenue by $56,056,608, removing the provision for rate refund through decreasing revenue by $12,346,571, and adding unbilled revenue by increasing revenue by $1,600,000. These adjustments, proposed by the Company, result in a net adjustment to decrease revenue by $66,803,179.

PUD recommends the Commission accept PUD's Adjustment No. B-2 to increase Materials and Supplies by $299,243 to the 13-month average balance based on the six-month post test year. PUD compared the Materials and Supplies 13-month average balance based on the six-month post test year of $127,899,873 to OG&E's 13-month average balance of $127,600,630.

PUD recommends the Commission accept PUD's Adjustment No. B-3 to increase Coal and Oil Inventories by $1,389,919 to the 13-month average balance based on the six-month post test year. PUD compared the Coal and Oil Inventories 13-month average based on the six-month post test year of $79,241,890 to OG&E's 13-month average balance of $77,851,970.

PUD recommends the Commission accept PUD Adjustment No. B-4, in the amount of $1,229,162, to decrease the level of Gas in Storage to the 13-month average balance based on the six-month post test year. PUD compared the Gas in Storage 13-month average based on the six-month post test year of $4,806,032 to OG&E's 13-month average balance of $6,035,194.

PUD recommends Adjustment No. B-5 to increase Prepayments Expense by $278,416 to the 13-month average balance based on the six-month post test year. PUD compared the Prepayments Expense 13-month average based on the six-month post test year of $7,121,945 to OG&E's 13-month average balance of $6,843,529.

PUD recommends PUD Adjustment No. H-3 which will decrease OG&E's requested Outside Services / Attorney Fees by $2,835. While reviewing invoices, PUD discovered that 7% of a $40,500 invoice was estimated to be related to influencing legislation. As this amount of $2,835 does not facilitate the provision of electric service, and because legislative advocacy expenses are to be reported below the line, PUD recommends that this expense should not be passed on to the ratepayers. Thus, 7% of the $40,500 results in a PUD-recommended adjustment to decrease Outside Services / Attorney Fees by $2,835.

PUD recommends PUD Adjustment No. H-4 to amortize Rate Case Expenses to the actual incurred level of expenses. PUD's recommended adjustment will result in a decrease of $152,230 from the $533,445 per year of Rate Case Expenses requested by OG&E. PUD recommends that the Company only recover the actual Rate Case Expenses incurred and that these expenses are amortized over two years. This adjustment would decrease OG&E's Rate Case Expenses from $1,066,891 to $762,432.

PUD recommends PUD Adjustment No. H-5 to remove unnecessary expenses from Rate Case Expenses. This adjustment removes the actual amount the Company has incurred thus far, with respect to the expert witness fees of Dr. Russell R. Evans, which results in a decrease of $10,325 per year for two years. Further, PUD recommends the Commission disallow all future fees associated with this expert witness for this Cause.

PUD requests the Commission accept the following recommendations:

(1) PUD's recommended cost of equity of 8.75%, which is the midpoint, rounded to the nearest quarter percent, in a range of reasonableness between 8.24% and 9.24%;
(2) The Company's proposed cost of debt of 5.32%, and capital structure consisting of 46.7% debt and 53.3% equity;
(3) Full recovery of Short-Term Incentive Compensation in the amount of $17,973,228;
(4) The Company's proposed removal of Long-Term Incentive Compensation in the amount of $5,487,519;
(5) The Company's proposed increase to Payroll Expense in the amount of $3,292,166;
(6) The Company's proposed increase to Pension Expense and related Pension Regulatory Liability in the amount of $44,020,013, and its proposed amortization period of five years, resulting in an annual benefit to customers in the amount of $8,804,003;
(7) PUD Adjustment No. B-2, to increase Materials and Supplies by $299,243 to the 13-month average balance based on the six-month post test year;
(8) PUD Adjustment No. B-3, to increase Coal and Oil Inventories by $1,389,919 to the 13-month average balance based on the six-month post test year;
(9) PUD Adjustment No. B-4, to decrease the level of Gas in Storage by $1,229,162 to the 13-month average balance based on the six-month post test year;
(10) The Company's proposed an adjustment to remove all fuel expenses and purchased power costs for the test year in the amount of $787,820,444 from operating expense, while leaving $76,402,988 in base rates for cogeneration capacity payments;
(11) The Company's proposed an adjustment for Unbilled Revenue and Over/Under Recoveries amount of net decrease in revenues of $66,803,179;
(12) PUD Adjustment No. B-5, to increase Prepayments Expense by $278,416 to the 13-month average balance based on the six-month post test year;
(13) PUD's recommended adjustment H-3 to decrease Outside Services / Attorney Fees by $2,835;
(14) PUD's recommended adjustment H-4 to amortize Rate Case Expenses to the actual incurred level of expenses. This adjustment will result in a decrease of $152,230 from the $533,445 per year of Rate Case Expenses requested by OG&E; and
(15) PUD's recommended adjustment H-5 to remove unnecessary expenses from Rate Case Expenses over two years. This adjustment will remove $10,325 of unnecessary expenses from Rate Case Expenses over two years.

OVERVIEW OF PUD REVIEW

Q: Please list the areas reviewed by members of PUD.

A: The table below outlines PUD analysts and their assigned areas in this Cause:

Analyst	Assigned Areas
Geoffrey M. Rush	Lead Analyst
Andrew Scribner	Advertising Expenses Dues & Donations Information/Instructional/Misc./Sales Expense Legal Settlements
Tonya Hinex-Ford	Internal Auditor's Reports Regulatory Financial Report SEC Form 10-K Board Minutes Organizational Chart Annual Report Revenue Not-at-Issue
Isaac Stroup	Storm Amortization Expense Removal Corporate Expenses/Overheads and Allocations Other Amortization Adjustment to Regulatory Assets and Liabilities
Amy Taylor	Administrative Expenses Misc. General Expenses Employee Medical Benefits Insurance/Self Insurance Expenses Misc. Revenues Bad Debt Expense Lease/Rent Expenses
EJ Thomas	Contribution-in-Aid of Construction/Customer Advances Refundable CIAC Interest on Customer Deposits Renewable Energy Certificates Wind Power Expense Customer Deposits Investment Tax Credits

David Melvin	Depreciation Expense Accumulated Depreciation adjusted to the 6-month post test year Accumulated Depreciation Differential adjustment AR AFUDC Adjustment Adjust TYE CWIP balance for projects with a completion date more than 6 months past the TYE, reimbursable projects, and projects that are revenue producing Plant, Depreciation, and Deferred Taxes related to the holding company assets Transfers and Adjust CWIP completed from October 2017-March 2018 Adjust Plant-in-Service for Plant Held for Future Use Adjust Plant to reflect estimated balance transferred to Plant-in-Service at March 31, 2018 Plant O&M Expenses Acquisition Adjustment Amortization Summary of Operating Expenses
Jason Chaplin	SPP Expenses Transmission Expense Recovered from LSEs SPPCT Rider Expense Removal Intercompany SPP Fees Remove Transmission Investment charged to third parties Mustang Plant Cost of Service Vegetation Management – Distribution Vegetation Management – Transmission
Kathy Champion	Manual Posting Adjustment Rider Revenues Best Bill Customer Growth and Annualization Demand Program Savings Free Service, LIAP, and Sr. Citizen Discount Rate Recalculation Demand Side Management Expense Removal Re-establish Special Contracts Tariff Changes Revenue Growth Rate Design
Geoffrey M. Rush	Pension and Post-Retirement Benefits Amortization of Pension Regulatory Liability Pension Cost Accrual Procedure Long-Term Incentives Short-Term Incentives Directors' Fees & Executive Salaries Executive Salary Surveys

	Wage and Salary Surveys Payroll Expense Return on Equity Outside Services/Attorney Fees Rate Case Expenses Regulatory Expenses Non-Recoverable Expenses
Zachary Quintero	Current Income and Accumulated Deferred Income Taxes Federal and State Income Tax Computation Property Tax Expense Ad Valorem Taxes Adjustment to Cash Working Capital Lead Lag Study Factoring Expense Adjustments Cash Working Capital Interest Synchronization Adjustment to ADIT and Deferred Tax Regulatory Liability
Marydoris Casey	Large Invoices
Jason Lawter	Weather Normalization
Zachary Quintero	Accounting Exhibit

Q: How did PUD determine the areas to be reviewed in this Cause?

A: PUD reviewed OG&E's application package and assigned all of the major areas listed in the application package.

Q: Please explain PUD's overall review process in this Cause.

A: PUD reviewed all testimony, schedules, and workpapers provided by the Company as part of the Application in this Cause. Further, PUD reviewed Commission orders, testimony related to areas in prior causes, and workpapers relating to OG&E. PUD communicated with the Company through email, phone calls, in-person reviews, data requests, and reviewed responses to those requests, including the data requests issued by other parties along with the related responses.

Q: Did PUD perform any onsite audits during its review of this Cause?

A: Yes. PUD performed weekly onsite audits at the Company's office in Oklahoma City, Oklahoma, in addition to attending tours of the Mustang, Sooner, and McClain power plants.

Q: In reviewing the Application, was PUD able to audit every book entry made by OG&E during the test year?

A: No. It is impractical for PUD to review every account and entry made during the test year. However, PUD reviewed areas that had a major impact on the rates and charges passed through to ratepayers. PUD performed a review of sample entries to accounts to ensure proper posting, accounting, and allocation.

Q: From a policy viewpoint, would you please describe PUD's role in this Cause?

A: PUD's role in this review, and analysis of any Company filing for a change or modification in rates and tariffs, is to be as objective as possible. PUD balances the interests between the Company and the ratepayers. PUD strives to make recommendations that are considered fair, just, and reasonable, and that allow the Company to provide safe and reliable service to its ratepayers at a reasonable rate.

PUD'S REVIEW PROCESS

Q: Please explain the review process for the specific assignments in this Cause.

A: PUD reviewed the application of OG&E, as well as the Direct Testimony and supporting workpapers of Company witnesses. In addition, PUD issued and reviewed data requests and conducted weekly onsite audits at the Company's corporate office in Oklahoma City, Oklahoma, to review confidential information.

LEGAL STANDARD

Q: What is the legal standard governing the allowed rate of return on capital investments for regulated utilities?

A: I am not an attorney, and the cases below are to provide historical context. In *Wilcox v. Consolidated Gas Co. of New York*, the U.S. Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate, allowed rate of return. Later, in two landmark cases, the U.S. Supreme Court set forth the standards by which public utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and

> economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[3]

In *Federal Power Commission v. Hope Natural Gas Company*, the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[4]

The *Hope* and *Bluefield* decisions set forth the following primary standards to be considered when determining a fair rate of return for public utilities:

1. <u>Corresponding Risk</u> – Risk is the most important factor when assessing the required return on equity. A utility's return should be less than the return of riskier enterprises; and
2. <u>Financial Soundness</u> – A utility is entitled to a return sufficient to maintain its credit, attract capital, and remain financially sound under efficient and economical management.

The cost of capital models used in PUD's review aligns with these standards and has been widely accepted by regulatory commissions around the country for many years.

Q: Should the allowed rate of return equal the return required by the Company's investors?

A: Yes. The Supreme Court standards indicate that the allowed return set by the Commission in this Cause should equal the true required rate of return of the Company's equity investors. The models used in this Cause assist in indicating the true required rate

[3] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).
[4] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

of return for the Company. If the Commission sets the allowed return equal to the true required return, it will allow the Company to maintain its financial integrity and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return higher than the true required return, it can result in a transfer of wealth from ratepayers to shareholders. In an effort to strike a balance, traditional regulatory practice allows the Commission to establish a rate of return within a range of reasonableness – one that balances the interests of ratepayers and shareholders. The best starting point for assessing a reasonable range for the allowed return, however, is assessing the true required return on equity.

GENERAL CONCEPTS AND METHODOLOGY

Q: Please describe the general concept of the cost of capital.

A: The cost of capital for a firm refers to the weighted average cost of all types of securities issued by the firm, including debt and equity. Determining the cost of debt is relatively straightforward. Interest payments on bonds are contractual, and are calculated by dividing total interest payments by the book value of outstanding debt. Determining the cost of equity, however, is more complex. Unlike the known, contractual cost for fixed debt securities, there is no explicit cost of common equity. The return on equity is not known until after the prior claims of bondholders have been satisfied. While the return on equity is known after the fact, the cost of equity, or the required return of stockholders, must be estimated before a firm begins a capital project so it can be sure the project will generate enough cash flow to satisfy the required return of its investors. To determine the appropriate cost of equity capital, firms estimate the return their equity investors will demand in exchange for giving up their opportunity to invest in other securities or postponing their own consumption, all while assuming some level of risk that they will realize a negative return on their investment. Once firms estimate the required return on equity, they can calculate their overall weighted average cost of capital ("WACC"), which includes the cost of debt. Competitive firms use their WACC as the discount rate to determine the value of capital projects. The cost of equity (C_E) is one of the most important variables for the Commission to impute accurately. In addition, the Commission must also determine the appropriate capital structure, which is comprised of the debt ratio (D/ (D+E)) and the equity ratio (E/ (D+E)).

Q: What is PUD's general approach in estimating the cost of equity in this Cause?

A: While a competitive firm must estimate its own cost of capital to assess the profitability of capital projects, regulators act as a surrogate for competition, and must estimate a utility's cost of capital to determine a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The following models used in this Cause have been widely used and accepted in regulatory proceedings for many years: (1) Discounted Cash Flow Model ("DCF"); (2) Capital Asset Pricing Model ("CAPM"); and (3) Comparable Earnings Model ("CEM"). In addition, a market analysis was performed to outline utility company risks in relation to the market as a whole, and provide insight as to the level of return that actual investors are expecting to receive when investing in these types of funds. The specific inputs and calculations for these models will be described in more detail.

Q: Why were multiple models used to estimate the cost of equity?

A: The models used to estimate the cost of equity attempt to measure the required return of equity for investors by estimating a number of different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of inconsistency, especially depending on the reliability of the inputs used in the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the allowed rate of return.

THE PROXY GROUP

Q: What are the benefits of choosing a proxy group of companies in conducting cost of capital analyses?

A: The cost of equity models in this Cause can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a necessity when the target company is a subsidiary that is not publicly traded, as is the case with OG&E. This is because the financial models used in this Cause require information from publicly traded firms, such as stock prices and dividends.

Q: What were the criteria used to determine the proxy group selection?

A: The proxy group consisted of 17 publicly traded companies identified by Value Line Investment Survey as electric utilities. Additional criteria for the proxy group were as follows:

1. At least 70% of revenues from electric sales;
2. A Value Line safety rank of "3" or better; and
3. A Value Line financial strength of "B" or better.

DISCOUNTED CASH FLOW ANALYSIS

Q: Please describe the Discounted Cash Flow model.

A: The DCF Model is based on a fundamental financial model called the dividend discount model, which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. The General DCF Model would require an estimation of an infinite stream of dividends. Since this would be impractical, analysts use more feasible variations of the General DCF Model.

Q: Do all DCF Models rely on several underlying assumptions?

A: Yes, the DCF Models rely on the following four assumptions:

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;

2. Investors discount the expected cash flows at the same rate (k) in every future period;
3. The (k) obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and
4. Dividends, rather than earnings, constitute the source of value.

Q: Describe the Constant Growth DCF Model.

A: The General DCF can be rearranged to make it more practical for estimating the cost of equity; therefore, regulators typically rely on some variation of the Constant Growth DCF Model. Unlike the General DCF Model, the Constant Growth DCF Model solves directly for the required return (k). In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be substituted with a term representing the expected constant growth rate of future dividends (g). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (g). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

Q: Does the use of the Constant Growth DCF Model require additional assumptions?

A: Yes. In addition to the four assumptions listed above, the Constant Growth DCF Model relies on four additional assumptions as follows:

1. The discount rate (k) must exceed the growth rate (g);
2. The growth rate (g) is constant in every year to infinity;
3. Investors require the same return (k) in every year; and
4. There is no external financing; that is, growth is provided only by the retention of earnings.

Since the growth rate is assumed to be constant, it is important not to use growth rates that are unreasonably high.

Q. Describe the Quarterly Approximation DCF Model.

A: The basic form of the Constant Growth DCF Model described above is sometimes referred to as the Annual DCF Model. This is because the model assumes an annual dividend payment to be paid at the end of every year, as well as an increase in dividends once each year. In reality, however, most utilities pay dividends on a quarterly basis. The Constant Growth DCF equation may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF Model. The Quarterly Approximation DCF Model assumes that dividends are paid quarterly and that each dividend is constant for four consecutive quarters. All else held constant, this model actually results in the highest cost of equity estimate for the utility in comparison to other DCF Models because it accounts for the quarterly compounding of dividends. There are several other variations of the Constant Growth DCF Model, including a Semi-Annual DCF Model, which is used by the Federal Energy Regulatory Commission. Regulatory proceedings have accepted these models, along with the Quarterly Approximation DCF Model, as useful tools for estimating the cost of equity. For this Cause, PUD chose the Quarterly Approximation DCF Model described above.

Q: What are the inputs of the DCF Model?

A: There are three primary inputs in the DCF Model: stock price (P_0), current dividend (D_0), and the growth rate (g). The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated.

Q: How was the stock price input of the DCF Model determined?

A: For the stock price (P_0), a one-month average of stock prices for each company in the proxy group was used. Analysts sometimes rely on average stock prices for longer periods. However, according to the efficient market hypothesis, markets reflect all relevant information available at a particular time, and prices adjust instantaneously with the arrival of new information. Past stock prices reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q: Why was a 30-day average used for the current stock price input?

A: Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles. This avoids any irregularities that may arise from using a single current stock price. Choosing a current stock price for one particular day during that time could raise an issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is not advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing volatility. As a result, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to concepts of market efficiency and avoiding any irregularities that may arise from using a single stock price on a given day. The stock prices used in the

DCF analysis are one-month averages of adjusted closing stock prices for each company in the proxy group.

Q: How was the dividend input of the DCF Model determined?

A: The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. The quarterly dividend paid in the first quarter of 2018 for each proxy company was obtained. The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Therefore, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

Q: Does the Quarterly Approximation DCF Model result in a higher cost of equity relative to other DCF Models, all else held constant?

A: Yes. The DCF Model used in this Cause results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the quarterly compounding of dividends inherent in the model.

Q: How was the growth rate input of the DCF Model determined?

A: While the stock price and dividend inputs of the DCF Model are known figures that can be obtained, the growth rate must be estimated. For this reason, the growth rate is usually the most contested input of the DCF Model. The methods used to estimate the growth rate for each proxy company were: (1) historical dividend growth; and (2) projected earnings growth.

Historical Dividend Growth

Observing historical growth rates in dividends, earnings, and book value is a reasonable method for estimating future growth, especially for utility companies. This is because utilities tend to have stable earnings and pay dividends in a consistent manner. One primary advantage of using historical data is that it is known. In the DCF Model, historical dividend growth over the last five years for each proxy company was used. While it would not be unreasonable to use historic earnings or book value, the DCF theory states that it is the expected future cash flows in the form of dividends that constitute investment value. As a result, it makes sense to consider actual dividend growth when estimating the growth rate in the DCF Model.

Projected Earnings Growth

In addition to considering historic dividend growth, projected earnings growth was considered. Since the ability to pay dividends stems from a company's ability to generate earnings, it is expected that earnings growth will have an influence on dividend growth. One potential drawback of using earnings growth is that earnings tend to be much more volatile than dividends. In the DCF Model, the projected earnings for each proxy company were considered.

Q: What are the results of your DCF Model?

A: The Quarterly Approximation DCF Model was used to estimate the cost of capital for each proxy company. The inputs of the DCF Model for each proxy company included a

30-day average of stock prices for the current stock price, the dividends reported in the first quarter of 2018, and an average of two reasonable methods for determining the growth rate. The average DCF result of the 17 proxy companies using the Quarterly Approximation DCF Model is 9.84%, which is the result that was considered in PUD's final cost of capital recommendation, along with the results of the other models.

CAPITAL ASSET PRICING MODEL ANALYSIS

Q: Describe the CAPM.

A: The CAPM is a market-based model founded on the principle that investors demand higher returns for incurring additional risk. The CAPM estimates this required return.

Q: What are the assumptions inherent in the CAPM?

A: The CAPM relies on the following assumptions:

(1) Investors are rational, risk-averse, and strive to maximize profit and terminal wealth;
(2) Investors make choices on the basis of risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;
(3) Investors have homogenous expectations of risk and return;
(4) Investors have identical time horizons;
(5) Information is freely and simultaneously available to investors;
(6) There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;
(7) There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and
(8) Total asset quality is fixed, and all assets are marketable and divisible.

The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

Q: Does the CAPM promote the legal standards set forth by the U.S. Supreme Court?

A: Yes. The CAPM directly considers the amount of risk inherent in an individual company. According to the Supreme Court in its decision in *Federal Power Commission v. Hope Natural Gas Company*, "the amount of risk in the business is a most important factor" in determining the appropriate, allowed rate of return. The Court also held that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." The CAPM is the strongest of the three models presented in this Cause, because it is the only model that directly measures the most important component of a fair rate of return analysis: risk.

Q: Please describe the CAPM equation.

A: There are three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β_i); and (3) the market risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate. Each term is discussed in more detail below, along with the inputs that were used for each term.

Q: What is the risk-free rate?

A: The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q: Is it preferable to use the yield on long-term Treasury Bonds for the risk-free rate in the CAPM?

A: Yes. In valuing an asset, investors estimate cash flows over long periods. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. As a result, short-term Treasury Bill yields should not be used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and can thus lead to unreliable estimates. Instead, long-term Treasury Bonds are used to represent the risk-free rate in the CAPM. A 30-day average of daily Treasury yield curve rates on 30-year Treasury Bonds was used as the risk-free rate estimate, which resulted in a risk-free rate of 3.05%.

Q: What is the beta coefficient?

A: Beta measures the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance.

Q: How were the betas discovered for the proxy companies?

A: PUD obtained the beta results from Value Line Investment Survey.

Q: What is the equity risk premium?

A: The final term of the CAPM is the equity risk premium ("ERP"), which is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. There are three ways to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied equity risk premium. The CAPM analysis incorporated each of these methods in determining the ERP.

Q: Describe the historical equity risk premium.

A: The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because the data is easy to obtain. There are three important factors to consider when estimating the historical ERP: (1) the period of time; (2) the choice of the risk-free rate; and (3) whether to use geometric or arithmetic averages.

Q: Is it preferable to use longer periods when calculating the historic ERP?

A: Yes. Calculating returns over longer periods is preferable because the results produce a smaller standard error, and are thus more reliable. Using at least 50 years of data is ideal. Returns from 1926 through 2014 were considered in developing PUD's historical ERP estimate in this Cause.

Q: Should the rate on long-term Treasury Bonds be used as the risk-free rate?

A: Yes. In corporate finance and valuation, the rate on long-term Treasury Bonds is typically used as the risk-free rate, and as discussed above, short-term Treasury Bill yields are rarely used in the CAPM to represent the risk-free rate because they are subject to greater volatility and can lead to unreliable estimates. The difference between returns on stocks and returns on long-term government bonds was considered in the historical ERP estimate.

Q: Is it better to use the geometric average rather than the arithmetic average when looking at historical returns over time?

A: Stocks are negatively correlated (i.e., good years are more likely to be followed by poor years and vice versa), and thus the arithmetic average tends to overstate the true ERP. When returns are volatile, the arithmetic average can produce questionable results.

The geometric average, however, is more appropriate when measuring returns over a long period of time, which is done when calculating the historical ERP. Although the geometric average is considered more appropriate when looking at the historical ERP, the higher arithmetic average was considered in the historical ERP calculation.

Q: Describe the actual results of the historical ERP analysis.

A: According to Ibbotson, the historical ERP using the geometric average is 4.4%, while the historical ERP using the arithmetic average is 6.0%. The average of these two numbers is 5.2%, which is the figure used in the historical ERP estimate.

Q: What are the limitations of relying solely on a historical average to estimate the forward-looking ERP?

A: Many investors use the historical ERP because it is convenient and easy to calculate. What matters in the CAPM model is not the actual risk premium from the past, but rather the expected risk premium looking forward. Some investors may think that a historic ERP provides some indication of what the prospective risk premium is, but there is empirical evidence to suggest the prospective, forward-looking ERP is actually lower than the historical ERP. Regardless of the variations in historic ERP estimates, many scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal.

Q: Describe the expert survey approach to estimating the ERP.

A: The expert survey approach to estimating the ERP involves conducting a survey of experts ranging from professors, analysts, chief financial officers, and other executives around the country and asking them what they think the expected ERP is. Graham and Harvey have performed such a survey every quarter since 1996. In their survey during the first quarter of 2016, they found that experts around the country believe that the current risk premium is 4.51%. The IESE Business School conducts a similar expert survey. Its expert survey reported an average ERP of 5.5%. Averaging the ERP results from both surveys provides an ERP of 5.01%.

Q: What are the results of the final ERP estimate?

A: In determining the final ERP to use for the CAPM model, PUD used a weighted average of the expert survey and the implied equity risk premium. While it would not be unreasonable to use any of these methods by themselves to estimate the ERP, it is more prudent to consider both methods, as the methods are not equal in value. PUD used a final ERP of 5.04% in the CAPM calculation.

Q: What are the results of the CAPM analysis?

A: Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, PUD calculated the CAPM cost of equity for each proxy company. The average CAPM cost of equity of the 17 proxy companies is 6.65%, which was the rate that was considered in the final cost of equity analysis in this Cause.

COMPARABLE EARNINGS ANALYSIS

Q: Describe the Comparable Earnings Model.

A: In contrast to the DCF and CAPM models, which are market-based models, the CEM is an accounting-based model. That is, the CEM relies on available accounting data, particularly the return earned on book equity. The CEM involves averaging the earned returns on equity of other utility companies.

Q: Is it more appropriate to conduct the CEM on a group of competitive firms, rather than a group of regulated utilities?

A: Yes. In utility rate cases, analysts often perform the CEM on the same proxy group of regulated utilities used in the CAPM and DCF analyses. Technically, however, it would be better to conduct this analysis on a group of unregulated, competitive firms with similar risk profiles and business operations. The reason analysts do not conduct the CEM on such a group of comparable competitive firms is that they arguably do not exist.

Q: What is the rationale behind choosing competitive firms for the CEM analysis?

A: The rationale behind choosing competitive firms for the CEM analysis is that the returns on equity of regulated utilities are based on past information, and were not earned under the restraints of competition. Regulators have a duty to stand in the place of competition, and that duty cannot be accomplished adequately by awarding returns on equity based on the earned returns of other utilities.

Q: How does the CEM analysis compare to the other models used in this Cause?

A: The CEM is the weakest of the three models presented in this Cause, as it does not account for any prospective, forward-looking factors (such as the growth rate in the DCF or the implied ERP in the CAPM), and it does not have any measure for risk (such as beta in the CAPM). Nonetheless, the CEM has been included here because it is unique to the regulatory environment, and as a result, regulators have become familiar with seeing this model in rate cases.

Q: What are the results of the Comparable Earnings Model?

A: In conducting the CEM analysis, PUD averaged the annual earned returns on equity for each of the 17 proxy companies from 2013 through 2017. The composite average and final result of the CEM is 9.84%, which was the rate that was considered in the final cost of equity analysis in this Cause.

MARKET ANALYSIS

Q: What is the general relationship between risk and return?

A: According to the Supreme Court decision rendered in *Federal Power Commission v. Hope Natural Gas Company*, risk is among the most important factors for the Commission to consider when determining the allowed return. There is a direct relationship between risk and return in that the more risk an investor assumes, the larger return the investor will demand. Two primary types of risk affect equity investors – firm-specific risk and market risk. Firm-specific risk affects individual firms, while market risk affects all companies in the market to varying degrees.

Q: What are the differences between firm-specific risk and market risk?

A: Firm-specific risk affects individual companies rather than the entire market. There are several types of firm-specific risks, including:

(1) Financial Risk – The risk that equity investors of leveraged firms face as residual claimants on earnings;
(2) Default Risk – The risk that a firm will default on its debt securities; and
(3) Business Risk – The risk that encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company.

While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, it affects all firms in the market.

Q: Is firm-specific risk diversifiable?

A: Yes. Diversification eliminates firm-specific risk. Rational investors are risk-averse and seek to eliminate risk they can control. Investors can eliminate firm-specific risk by adding more stocks to their portfolio through diversification. There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. As a result, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio. Second, the effects of firm-specific actions on stock prices can be either positive or negative for each stock. In large portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.

Q: Does the market reward firm-specific risk?

A: No. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company, and the market does not reward all risks associated with an individual firm's operations. In contrast, diversification cannot eliminate market risk. Market risks, such as interest rate risk and inflation risk, affect all stocks in the market to different degrees. Because diversification cannot eliminate market risk, investors who assume higher levels of market risk also expect higher returns. Market risk is the only type of risk the market rewards and is the primary type of risk the Commission should consider when determining the allowed return. Utility companies are considered defensive companies. This means that the demands for utilities are consistent regardless of the state of the economy. In times of recession, individuals may opt to cut back on items that are not necessary (vacations, movies, dinners out, etc.) to compensate. However, during times of recession, individuals will always have a need for gas, water, and electricity.

Q: How is market risk measured?

A: Market risk is considered when estimating the cost of equity. Investors who want to eliminate firm-specific risk must hold a fully-diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta." Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases by 1.0%, a stock with a beta of 1.5 will, on average, increase by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk. Thus, stocks with low betas are relatively insulated from market conditions. Beta is used in the Capital Asset Pricing Model to estimate the required return on equity.

Q: Are public utilities defensive firms that have low betas, low market risk, and are relatively insulated from overall market conditions?

A: Yes. Although market risk affects all firms in the market, it affects utilities to varying degrees. Firms with high betas are affected more by market risk than firms with low betas, which is why firms with high betas are more risky. Companies in defensive industries, such as utility companies, will have low betas and performance that is relatively unaffected by overall market conditions. When the economy is in a recession, as occurred toward the end of the 2000s and continued into the early 2010s, consumers can be assured that their utility companies will be able to maintain normal business operations, and utility investors can be confident that utility stock prices will not widely fluctuate. While it is preferable that utilities, as defensive firms, experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Commission's allowed return.

Q: Do investors in firms with low betas require a smaller return than the average required return on the market?

A: Yes. This is the basic concept of the risk and return: the more risk an investor assumes, the larger return the investor will demand. So, if a particular stock is less risky than the market average, an investor holding that stock will require a smaller return than the average return on the market. Since utilities are low-risk companies with low betas, the required return for utilities is lower than the required return on the overall market.

Q: Why does PUD believe this is a reasonable approach?

A: Observing and monitoring actual returns of utility funds in the market is reasonable for two reasons: (1) it highlights the types of returns that individuals who invest in these types of companies expect to earn; and (2) market returns provide a guideline by which to properly incentivize utility companies based on their actual risk.

Q: Describe the Market Analysis that was used.

A: PUD reviewed the market prospectuses and fact sheets of the top 14 utility funds.[5] A fund prospectus is a disclosure document which provides investors with material information, such as a description of the fund, biographies of officers and directors, and information outlining the historical performance of the fund in different segments of time. The historical performance listed represents the actual historical returns, and these returns are what investors look at to anticipate an expected return when investing in these funds. PUD's analysis included the actual returns during 3-year, 5-year, and 10-year periods, and the 10-year average for the utility funds fell in the range of 5.91% to 8.57%.[6] The average of the 14 funds analyzed was 6.49%.

PUD also looked at the historical performance of the 17 companies in the proxy group. PUD's analysis included the actual returns during 3-year, 5-year, and 10-year periods, and the 10-year average for the utility funds fell in the range of 4.60% to 11.73%.[7] The average of the proxy group, as used in PUD's final analysis, was 8.62%.

[5] http://news.morningstar.com/fund-category-returns/utilities/$FOCA$SU.aspx.
[6] Putnam Global Utilities return of 1.71% was disregarded as an outlier.
[7] PPL Corporation's return of -0.02% and PNM Resource's return of 13.71% were disregarded as outliers.

Q: Why was the 10-year average used in the analysis?

A: Utilities are likely to underperform during times of market growth; however, during periods of recession, as experienced during the late 2000s and early 2010s, utilities tend to outperform the market. Monitoring the performance of a fund over a longer period is more conducive to arriving at an accurate number, and reflects a more comprehensive sample of market conditions.

Q: Please describe the trend with respect to Awarded ROEs.

A: PUD reviewed the historical awarded ROEs of the two largest Investor-Owned Electric Utilities in Oklahoma. The results are listed on Table 1 below:

Table 1: Awarded ROE – Oklahoma Investor Owned Utilities

	Company	Cause No.	Final Order No.	Requested ROE	Awarded ROE
1	OG&E	2005-00151	516261	11.75%	10.75%
		2008-00398	596281	12.25%	10.75%
		2015-00273	662059	10.25%	9.50%
		2017-00496	TBD	9.90%	TBD
2	PSO	2013-00217	639314	10.50%	9.85%
		2015-00208	657877	10.50%	9.50%
		2017-00151	672864	10.00%	9.30%

As this table illustrates, the ROEs that have been requested by the companies have not been granted. In addition, the awarded ROEs have been gradually declining toward a more appropriate level.

COST OF DEBT

Q: Describe OG&E's position regarding long-term debt financing.

A: OG&E had $2,985,002,653 of long-term debt capital during the test year at a cost of 5.32%.

Q: Discuss PUD's recommendation regarding OG&E's proposed cost of debt.

A: As discussed above, unlike the cost of equity, the cost of debt is based on contractual interest rates. The Company's proposed cost of debt of 5.32% is reasonable, and PUD recommends the pre-tax cost of debt rate of 5.32% as proposed by the Company.

COST OF DEBT AND CAPITAL STRUCTURE

Q: Describe the concept of capital structure.

A: Capital structure refers to the way a firm finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as residual claimants. The fact that stockholders have a lower priority to claims on company assets increases their risk and required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q: Can competitive firms add value and reduce their WACC by increasing debt?

A: Yes, a competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This increases the risk of recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. If debt financing is too high, the firm's WACC will increase instead of decrease. A competitive firm's value is maximized when the WACC is minimized. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the additional risks to both bondholders and shareholders, as each type of investor will demand a higher return for the additional risk they have assumed.

Q: Does the rate base rate of return model incentivize utilities to operate at the optimal capital structure?

A: No. While it is true that competitive firms can maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant.

Q: Can utilities afford to have higher debt levels than other industries?

A: Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have higher levels of debt. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure. There are objective, technical methods available and discussed below to estimate the optimal capital structure.

Q: Discuss the capital structure of the proxy companies.

A: The capital structure for each proxy company was examined, as was the average of their debt and equity ratios. The average debt ratio of the proxy group is 50.9%. Regulators will sometimes simply look at the average debt ratio of the proxy group as a measure to determine the appropriate debt ratio of the target company. This type of analysis is oversimplified and insufficient for three important reasons:

(1) **Utilities do not have a financial incentive to operate at the optimal capital structure.**

Under the rate base rate of return model, utilities do not have a natural financial incentive to minimize their cost of capital. Competitive firms, in contrast, can maximize their value by minimizing their cost of capital. Simply comparing the debt ratios of other regulated utilities will not indicate an appropriate capital structure. Rather, it will indicate debt ratios that are too low. It is the Commission's duty to act as a surrogate for competition and ensure that the Company's capital structure is similar to one that the Company would have in a competitive environment. This duty cannot be accomplished by simply reviewing the current debt ratios of the proxy group or the target company.

(2) **The optimal capital structure is unique to each firm.**

As discussed further below, the optimal capital structure for a firm is dependent on several unique financial metrics for that firm. The other companies in the proxy group have different financial metrics than the target company, and thus have different optimal capital structures. An objective analysis should be performed using the financial metrics of the target utility in order to estimate its unique optimal capital structure.

(3) **The capital structures of the proxy group may not have been approved by their regulatory commissions.**

The actual capital structure of any utility falls within the realm of managerial discretion. Regulatory commissions, however, have a duty to impute a proper capital structure if the company's actual capital structure is inappropriate. Thus, the actual capital structures of other utilities may have been deemed inappropriate by their own regulatory commission. For all of the foregoing reasons, simply comparing the capital structures of other regulated utilities has no place in a proper capital structure analysis.

Q: Discuss PUD's recommended capital structure for OG&E.

A: OG&E has proposed a debt ratio of 47% in this Cause. Because it is the Commission's duty to act as a surrogate for competition, the Commission should approve a capital structure coincident with one that would exist in a competitive environment. As a result, PUD recommends OG&E's capital structure, which consists of 46.7% debt and 53.3% equity.

SHORT-TERM INCENTIVE COMPENSATION

Q: Please explain the Company's adjustment regarding Incentive Compensation.

A: OG&E's pro forma expense levels include $17,973,228 of annual or short-term incentive compensation. The Company has a compensation plan which encompasses four metrics: Earnings per Share ("EPS"), Operations and Maintenance ("O&M"), Customer Satisfaction, and Safety.

Q: What amount of recovery should the Commission allow with respect to short-term incentive compensation?

A: PUD recommends that the Commission allow full recovery of short-term incentive compensation for the following reasons:

(1) The Company's incentive plan includes compensation studies which look at companies that OG&E competes with for employees.

(2) The metrics are not inclusive of each other. As a result, there is no "trigger" which, when met, provides incentive payout.

(3) All four metrics benefit the Company, the ratepayers, and the shareholders.

Q: Why should a robust incentive plan include compensation studies?

A: The Company needs a variety of employees with experience, knowledge, and skills to provide efficient and affordable electric service to its customers. Two examples illustrate:

(1) The Company asks employees to fix and repair power lines that are damaged due to periods of inclement weather. These employees are required to have the

requisite skill and experience to safely and efficiently complete these tasks, sometimes while the inclement and dangerous weather is in progress. This is done to ensure service disruption is minimal, and power is fully restored to affected ratepayers in the most efficient manner.

(2) The Company asks employees to understand and maneuver increased operational complexities with its membership in SPP. To begin with, it is incumbent on the Company to have employees with proficient knowledge present in the many Working Groups and Task Forces that take place throughout the stakeholder process, to advocate OG&E's position. Further, the Company must have personnel at the plant with the skill and knowledge to not only be able to speak intelligently with SPP with respect to the constant changes in dispatch, etc., but also to actively participate in the Integrated Marketplace. Employees must effectively understand technical terms and concepts such as Locational Marginal Prices, Congestion, specifics of the plant, etc., to ensure they are bidding correct prices in both the Day-Ahead and Real-Time Markets. Membership and active participation in SPP provides the Company's ratepayers with increased savings in the form of lower prices for electricity.

Q: Why is it important to have the four metrics independent of each other, with respect to payout?

A: Although there is a financial component included in the Company's incentive compensation package, payout of incentive compensation is not "triggered" by financial performance. Each of the four metrics provided in the Company's incentive compensation plan provides a benefit to the Company, the ratepayers, and the shareholders. The Company benefits by having employees focused on creating a company which is financially sound, safe, reliable, and has efficient infrastructure in place. This in turn benefits ratepayers, as they can be assured of electric service which is reliable and provided at the lowest cost possible. Shareholders benefit by investing in a company which is financially strong, profitable, and has qualities that conservative investors are looking for when seeking new investment opportunities, which are low risk, defensive companies, which pays out a consistent dividend. Finally, because the metrics are independent of each other, and not based on financial performance, the Company's incentive compensation package allows employees to receive compensation for the areas that were met, and miss out on compensation in any areas that were not met. In not meeting payout in certain metrics, the Company is able to ascertain areas in which to improve.

(1) Focus on Earnings per Share benefits the Company, its shareholders, and its ratepayers. A high Earnings per Share is a very good indicator of the profitability of a utility, and indicates a financially strong company. This is attractive to shareholders, as a financially strong company has, among other things, low risk. In addition, being a financially strong electric utility company is important, as it is necessary for OG&E to be able to fund and support its operational processes. With the ability to support and fund its operational processes, the Company's ratepayers benefit, as they have a stake in the financial well-being of the Company through cheaper power that is more reliable and efficient. Technology is constantly changing, and as the Company endeavors to become more efficient,

it is imperative for OG&E to have the means to invest in the necessary infrastructure, systems, and processes necessary to provide its ratepayers with efficient power at a lower cost.

(2) Focus on O&M costs allows generating facilities to become cheaper to run and maintain. Attracting and retaining qualified personnel who are trained to proactively maintain OG&E's generating units provide benefits to both shareholders and ratepayers. Investors in utilities are looking for financially strong companies with stable interest and dividend income. If the Company has generating units that are routinely maintained and updated as necessary, these conservative investors have additional assurances and confidence that investing in a financially strong company, such as OG&E, will provide a consistent and stable return. Ratepayers also benefit through a focus on O&M. As systems are updated with newer and more effective technology, generating units can run more productively, power has the potential to be generated more cheaply, and additional generating units are able to potentially be committed by SPP in the Day-Ahead or Real-Time Markets.

(3) Focus on customer satisfaction benefits both ratepayers and shareholders. Ratepayers benefit from a focus on customer satisfaction by taking advantage of new technology and processes which promote communication and ease of payment. Social media and digital applications have become an avenue whereby the Company can effectively communicate with customers. Shareholders benefit by investing in a forward-thinking company which is consistently focusing on increasing customer needs.

(4) Focus on safety is an all around important metric for OG&E, not only for purposes of incentive compensation, but also to provide a safe place for employees to work. With the unique hazards of generating units found in utilities, processes and procedures are in place to ensure that employees are afforded a safe environment in which to work. Safe environments lead to decreased accidents, which can save the Company money. That money can be focused elsewhere for the betterment of the Company and ratepayers.

Q: Do the four metrics outlined above benefit both the shareholders and the ratepayers?

A: Yes. The Company's incentive plan includes metrics which benefit both shareholders and ratepayers, as both have an important stake in all four of the metrics detailed in the Company's incentive compensation plan. OG&E is a defensive company, which is attractive to conservative investors who are looking for a company that is financially sound, with low volatility. Ratepayers have a stake in the Company having a high Earnings per Share, and benefit by having power supplied by a financially strong company, who employs personnel that have the experience and knowledge necessary to perform the duties necessary to allow OG&E to be as efficient and reliable as possible, in addition to providing electric service at the lowest cost possible. As a result, both ratepayers and shareholders have a vested interest in all four facets of OG&E's incentive compensation plan, and the Company should receive full recovery.

Q: What is PUD's recommendation with respect to short-term incentive compensation?

A: PUD believes that it is prudent for the Company to have a comprehensive incentive plan, which is an important part of employee attraction and retention. If incentive plans were eliminated, and those dollars were inserted as base salary instead, compensation would still be in a range that is competitive with compensation packages provided by other like-sized companies. Although the compensation package does have a financial element, it is structured to where payout is not tied to financial performance. This results in allowing both the ratepayers and shareholders to benefit in the Company's incentive compensation package. PUD recommends that the Commission should allow 100% of Short-Term Incentive Compensation in the amount of $17,973,228.

LONG-TERM INCENTIVE COMPENSATION

Q: Is the Company requesting recovery of LTI?

A: No. The Company removed $5,487,519 of LTI from expenses. Although PUD has consistently recommended the recovery of 25% of LTI, the Company is not asking for recovery of LTI in this Cause.

PAYROLL EXPENSE

Q: Please describe the Company's proposed payroll adjustment.

A: In workpaper H-2-22, the Company is requesting an increase to payroll, in the amount of $3,292,166. To arrive at this number, this adjustment has three parts:

(1) Payroll was annualized based on the number of actual employees employed at the end of the test year.

(2) An increase was made to payroll to reflect raises implemented at the end of 2017.

(3) Payroll expenses after the test year were estimated to account for new employees added to the payroll, as well as employees no longer on the payroll.

Q: Is the Company using a different methodology concerning payroll than it has in previous rate cases?

A: Yes. In previous rate cases, OG&E used a process of estimating of payroll expense using test year expenses, which were then updated for expected post test year head count and wage changes. The change in methodology in this Cause aligns the Company's payroll practices with Final Order No. 662059 in Cause No. PUD 201500273, where the Company's adjustment to payroll was based on actual test year and post test year numbers and also accounts for employee raises of approximately 3%.

Q: What is PUD's recommendation with respect to Payroll Expense?

A: PUD recommends that the Commission should allow the Company's proposed increase to Payroll Expense in the amount of $3,292,166. PUD believes that the Company's methodology to annualize payroll at March 30, 2018, provides assurances that (1) any employees no longer employed, or employees hired by OG&E after the test year period, were accurately represented in the post test year numbers, and (2) the post test year Payroll Expense reflects actual payroll amounts after raises were given in 2017.

PENSION REGULATORY LIABILITY

Q: **Please describe the Company's proposed adjustment to Pension Regulatory Liability.**

A: The Pension Tracker was authorized in Cause No. PUD 200500151. The Company shows an expense in the amount of $44,020,103 and with the proposed amortization period of five years, results in a reduction to expenses (i.e., a credit to customers) in the amount of $8,804,003.

Q: Does PUD believe that a five-year amortization is appropriate?

A: Yes. PUD believes that a five-year amortization is an appropriate timeline.

MATERIALS AND SUPPLIES

Q: What Materials and Supplies are included in OG&E's rate base? Please explain the process used to review Materials and Supplies.

A: Materials and Supplies consist of the cost of materials purchased primarily for use in the utility business for construction, operation, and maintenance purposes. OG&E's pro forma adjustments for Materials and Supplies total $126,663,282. PUD reviewed the Direct Testimony of Jason Bailey, WP B-05, and the response to Data Request PUD KPL-1 to update the six-month post test year amounts. PUD compared the 13-month average based on the six-month post test year to OG&E's 13-month average balance for Materials and Supplies.

Q: What is PUD's recommendation for Materials and Supplies?

A: PUD recommends Adjustment No. B-2 to increase Materials and Supplies by $299,243 to reflect the 13-month post test year average balance. PUD used a 13-month average based on the six-month post test year from workpaper B-05, as well as the Company's response to Data Request PUD KPL-1. PUD compared the 13-month average based on the six-month post test year of $127,899,873 to OG&E's 13-month average balance of $127,600,630. This treatment is consistent with Final Order No. 662059 in Cause No. PUD 201500273.

ADJUST COAL AND OIL INVENTORIES TO REFLECT 13-MONTH AVERAGE

Q: Please explain what Coal and Oil inventories are included in the Company's rate base, and PUD's process for reviewing Coal and Oil Inventories.

A: Utilities' primary objectives within the Fuel Inventories account are to: (1) ensure a continuous supply of coal and oil, of an appropriate quality, to all of its coal and oil-fired generation stations; and (2) ensure delivery of coal and oil to those stations which will result in the lowest reasonable cost per kWh of electricity, within the constraints of safety, reliability of supply, unit design, and environmental requirements. OG&E's pro forma adjustments for Coal and Oil Inventories total $73,488,992. PUD reviewed the Direct Testimony of Jason Bailey, WP B-04, and the response to Data Request PUD KPL-1 to update the six-month post test year amounts. PUD compared the 13-month average based on the six-month post test year to OG&E's 13-month average balances for Coal and Oil Inventories. This treatment is consistent with Final Order No. 662059 in Cause No. PUD 201500273.

Q: What is PUD's recommendation for Coal and Oil Inventories?

A: PUD recommends Adjustment No. B-3 to increase the Coal and Oil Inventories by $1,389,919 to the 13-month average based on the six-month post test year. PUD used OG&E's 13-month average balance from WP B-3-4 and used Company responses to Data Request PUD KPL-1. PUD compared the 13-month average based on the six-month post test year of $79,241,890 to OG&E's 13-month average balance of $77,851,970.

ADJUST GAS IN STORAGE TO REFLECT 13-MONTH AVERAGE

Q: Please describe OG&E's adjustment for Gas in Storage.

A: OG&E proposed an increase to natural gas inventory in the amount of $2,387,726. Cushion Gas Inventory was part of the current transmission agreement between OG&E and Enable Gas Transmission ("Enable"). This agreement was in effect during the test year. Under the terms of this transportation service agreement, Cushion Gas Inventory withdrawals only occur during the months of June, July, and August. The decrease in Gas in Storage for June 2017 through August 2017 is primarily due to withdrawals from the Cushion Gas Inventory. This agreement will end in April 2019 but the Gas in Storage will be fully depleted by August 31, 2018. OG&E does not lease any storage capacity from Enable and OG&E will no longer be adding Cushion Gas to Gas in Storage. PUD compared the 13-month average based on the six-month post test year of $4,806,032 to OG&E's 13-month average balance of $6,035,194. Therefore, PUD recommends Adjustment No. B-4, in the amount of $1,229,162, to decrease Gas in Storage to the 13-month average based on the six-month post test year to OG&E's 13-month average balance. This treatment is consistent with Final Order No. 662059 in Cause No. PUD 201500273.

Q: Please describe Cushion Gas.

A: Cushion Gas, also referred to as base gas, is the volume of gas that is in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Another way to describe it is the amount of gas required in a storage pool to maintain sufficient pressure to keep the working gas recoverable.

Q: Does PUD recommend a reduction and/or decrease to the adjustment to OG&E's Gas in Storage?

A: Yes. PUD recommends the following adjustment:

Table 1: Gas in Storage

OG&E proposed 13-month average	$6,035,194
PUD recommended 13-month post test year	$4,806,032
PUD recommended Adjustment No. B-4	$1,229,162

FUELS AND PURCHASED POWER EXPENSES

Q: Please describe OG&E's adjustment for Fuels and/or Purchased Power Expenses.

A: OG&E proposed an adjustment to remove all fuel expenses and purchased power costs for the test year that is passed to customers through the Fuel Adjustment Clause, excluding cogeneration capacity payments.[8] This adjustment removes $787,820,444 from operating expense, while leaving $76,402,988 in base rates for cogeneration

[8] Cause No. 201500273, Final Order No. 662059.

capacity payments. PUD reviewed WP-H-2-33, the test year general ledger, cogeneration capacity payments, and the curtailment general ledger in support of this adjustment. PUD reviewed and verified that all general ledger entries tied back to the workpapers. PUD recommends no adjustment to the Fuel and/or Purchased Power Expenses.

Q: Does PUD recommend any further adjustment to the Fuel and/or Purchased Power Expenses?

A: No.

UNBILLED REVENUES AND OVER/UNDER RECOVERIES

Q: Please describe OG&E's adjustment for Unbilled Revenues and Over/Under Recoveries.

A: OG&E proposed an adjustment to remove Unbilled Revenue and Over/Under Recoveries. This adjustment results in an increase in revenue in the amount of $1,600,000, as well as an addition of 62,275,618 kWh. PUD reviewed WP-H-2-1 concerning Unbilled Revenue, and the Company's Over/Under Recovery accounts, then traced and tied the journal entries to the workpapers. The removal of the over-recovery of fuel and rider collections decreased revenue by $56,056,608 and decreased the provision for rate refund by $12,346,571. The net decrease of $68,403,179 is arrived at by adding the over-recovery of fuel and rider collections in the amount of $56,056,608 to the provision for rate refund in the amount of $12,346,571. That sum of $68,403,179 is then decreased by the addition to Unbilled Revenue in the amount of $1,600,000, resulting in a net decrease in revenue of $66,803,179.

Q: Does PUD recommend any further adjustment to Unbilled Revenues and Over/Under Recovery?

A: No.

PREPAYMENTS EXPENSE

Q: Please describe the adjustment to Prepayments Expense.

A: OG&E proposed an adjustment of $2,305,107 to Prepayments Expense. OG&E's adjustment is based on the 13-month test year average of $6,843,529, which adjusted the test year end balance of $4,538,423. PUD reviewed the Direct Testimony of Jason Bailey, WP B-10, OG&E's responses to Data Request PUD KPL-1, and the six-month post test year updated balance.

Q: What is PUD's recommendation for Prepayments Expense?

A: PUD recommends Adjustment No. B-5 to increase Prepayments Expense by $278,416 to the 13-month average based on the six-month post test year. PUD used the 13-month average based on the six-month post test year of $7,121,945 obtained from information provided in the Company's response to Data Request PUD KPL-1. PUD compared the 13-month average based on the six-month post test year of $7,121,945 to OG&E's 13-month average balance of $6,843,529.

OUTSIDE SERVICES / ATTORNEY FEES

Q: Did OG&E propose an adjustment for Outside Services / Attorney Fees?

A: No.

Q: Does PUD have a recommended adjustment to Outside Services / Attorney Fees?

A: Yes. PUD's recommended adjustment is PUD Adjustment No. H-3 to decrease Outside Services / Attorney Fees by $2,835.

Q: Please explain PUD Adjustment No. H-3.

A: While reviewing invoices, PUD discovered that 7% of a $40,500 invoice was estimated to be related to influencing legislation. Because this expense of $2,835 does not facilitate the provision of electric service, and because legislative advocacy expenses are to be reported below the line, PUD recommends that this expense should not be passed on to ratepayers. Thus, 7% of the $40,500 results in a PUD recommended adjustment to decrease Outside Services / Attorney Fees by $2,835.

Q: Please explain PUD's audit for Outside Services / Attorney Fees.

A: PUD reviewed a listing of all of OG&E's vendor transactions involving Outside Services/ Attorney Fees during the test year. PUD compared these expenses to the past three years by FERC account and by vendor to determine fluctuations in excess of 10%. OG&E provided explanations of the fluctuations as well as general ledgers and invoices for these expenses. PUD then selected sample invoices to review and verify the expenses, and analyze information pertaining to these vendors. Through this analysis and multiple discussions onsite with Company representatives, PUD determined that the amount, other than the $2,835 related to Legislative Advocacy, included in the Outside Services / Attorney Fees expense was reasonable.

Q: Have there been any Company and/or accounting policy changes with respect to Outside Services / Attorney Fees?

A: No.

Q: What are some fluctuations and changes PUD discovered while auditing Outside Services / Attorney Fees?

A: PUD discovered that some vendor accounts had decreased to zero during the test year compared to 2016 expenses. OG&E's shift from performing work through Outside Services to performing work in-house caused these accounts to reflect this decrease. OG&E explained the reasons for these changes included streamlining processes, establishing cost savings, and implementing efficiency measures. PUD also discovered new vendor accounts and activity during the test year compared to previous years. PUD inquired about these new vendors and the increase of these accounts. OG&E explained that some of the new vendors that appeared on the list of vendors were added as a result of certain attorneys moving to different law firms.

REGULATORY EXPENSES

Q: Please summarize PUD's review of Regulatory Expenses.

A: PUD reviewed supporting documents and items included in Regulatory Expenses. PUD reviewed the Company's adjustment which reflects a normalized level of Regulatory Expenses. This increased operating expenses by $41,934. PUD then reviewed OG&E's adjustment to remove OCC assessment fees, which are recovered through a surcharge on customer bills, which results in a decrease of $2,316,326. Finally, PUD reviewed OG&E's adjustment to remove any remaining amortization of the deferred assets from previous Oklahoma Rate Case Expenses. This adjustment properly removes these expenses since these assets will be fully amortized by the time new rates go into effect. This adjustment resulted in a decrease of $916,392. All three of these adjustments proposed by OG&E are reflected in WP H 2-25. These three Company pro forma adjustments totaled a decrease of $3,190,785 to Regulatory Expenses.

Q: What is PUD's recommendation on OG&E's pro forma adjustment to Regulatory Expenses?

A: PUD does not recommend any adjustments to Regulatory Expenses related to the normalization of these expenses, OCC assessment fees, or prior Rate Case Expenses. PUD recommends the Commission approve OG&E's proposed pro forma adjustment WP H 2-25 in this Cause.

RATE CASE EXPENSES

Q: What is OG&E's proposed adjustment for Rate Case Expenses?

A: OG&E has estimated the total amount of Rate Case Expenses in WP H 2-39 to be $1,066,890.73. The Company requests to recover $533,445 annually for two years.

Q: What analysis did PUD perform regarding OG&E's Rate Case Expenses?

A: PUD reviewed legal fees, consultant contracts and fees, and other expense-related details included in the current test year and six-month post test year. PUD reviewed prior causes, the test year, and six-month post test year expenses. PUD also reviewed supporting documents for items included in the current Rate Case Expenses.

Q: How much of these expenses are attributable to the current rate Cause during the test year?

A: The forecast amount of current Rate Case Expenses, as reported in OG&E filings, the onsite supporting documentation, and the response to data request AG 1-23, totals $509,750. However, the amount of Rate Case Expenses actually incurred thus far is $205,290. PUD recommends that OG&E submit a final update of its Rate Case Expenses at the end of this Cause. This updated level of actual incurred and allowable costs, for Rate Case Expenses at the end of this Cause should be the level of expenses to be recovered over a two-year amortization period. Also, OG&E should provide all additional Rate Case Expenses until the Final Order is issued for this Cause.

Q: Which two adjustments is PUD recommending to Rate Case Expenses?

A: PUD is recommending PUD Adjustment No. H-4 to amortize Rate Case Expenses at the actual incurred level and PUD Adjustment No. H-5 to remove unnecessary expenses from Rate Case Expenses.

Q: Please explain PUD's Adjustment No. H-4 to amortize Rate Case Expenses at the actual incurred level of expenses.

A: OG&E has requested a recovery period of two years as shown by its pro forma adjustment in WP H 2-39, Rate Case Expense. Based on WP H 2-39, the filed application, onsite documentation, and responses to Data Request AG 1-23, the total current and remaining balance provided to PUD is as follows:

OG&E forecast and proposed Rate Case Expense	$509,750
Invoices on hand (current rate cause 17-496)	-$205,290
Remaining estimated balance to be incurred	$304,460
PUD Amortization Adjustment No. H-4 (as of now)	$152,230

Q: How does PUD Adjustment No. H-4 affect Rate Case Expenses?

A: PUD Adjustment No. H-4 will result in a decrease of $152,230 from the $533,445 per year for Rate Case Expenses requested by OG&E.

Q: What necessitates PUD Adjustment No. H-5 to remove unnecessary Rate Case Expenses?

A: Final Order No. 672864 for Cause No. PUD 201700151 states:

> Moreover, utilities should understand that not all rate case costs should be borne by ratepayers. Necessary and reasonable costs to process a rate case should be borne by ratepayers. Ratepayers should not be burdened with unreasonably inflated legal costs and expert witness fees, especially when the testimony of some expert witnesses may appear to be duplicative and/or unnecessary testimony.

PUD Adjustment No. H-5 decreases Rate Case Expenses by $10,325 to remove the actual amount the Company has incurred thus far, with respect to expert witness fees for Dr. Russell R. Evans. Further, PUD recommends the Commission disallow all future fees associated with this expert witness for this Cause. PUD believes that Dr. Evans' testimony is unnecessary and thus, his expert witness fees should not be borne by the ratepayers.

Q: Why does PUD believe that the costs associated with testimony of Dr. Evans' testimony is unnecessary?

A: First, Dr. Evans does not propose a specific Return on Equity ("ROE") in this Cause. Second, other Company witnesses, such as OG&E's Chief Financial Officer Mr. Stephen E. Merrill and outside consultant Dr. Roger A. Morin, have provided testimony relating to ROE, and PUD believes that Dr. Evans' testimony duplicates the testimony of both Dr.

Morin and Mr. Merrill. Third, PUD believes that OG&E has employees who are qualified, and have provided testimony regarding ROE in past causes, and should consider the option of having those employees testify on the subject of ROE. As the Company has qualified witnesses on staff, the costs for outside consultants are not necessary or reasonable, and should not be borne by ratepayers. However, for this cause, PUD recommends only the disallowance of the costs to retain Dr. Evans.

SPECIFIC RESPONSES TO COMPANY WITNESS TESTIMONY

Q: What general concerns do you have with respect to the testimony of Company witnesses Mr. Donald Rowlett, Dr. Russell Evans, and Mr. Steven Merrill?

A: In preparing testimony discussing ROE, the company hired two outside witnesses, Dr. Roger Morin and Dr. Russell Evans, and utilized two Company witnesses, Mr. Donald Rowlett and Mr. Steven Merrill, to speak on topics which overlap each other. Dr. Morin provides "traditional" testimony which outlines the models and analysis he used to reach his recommendation of an ROE of 9.9%. However, Dr. Evans, Mr. Rowlett, and Mr. Merrill each speak to the same general topic that a reasonable ROE (1) is necessary to obtain new financing and maintain financial integrity; (2) is necessary to compete with other companies with similar risk profiles for investors capital; and (3) is necessary for continued strong financial health. These are all important points; however, having four witnesses provide written testimony on these points is financially imprudent and redundant.

Q: What are your specific responses to Mr. Donald Rowlett?

A: Mr. Rowlett provides written testimony which discuses the overall relief requested by the Company. Included in his testimony is language which speaks to the importance of a reasonable ROE. He states, "[i]nvesting in infrastructure is a long-term commitment that typically serves customers for many decades."[9] While this statement is generally true, Mr. Rowlett fails to explain how investing in infrastructure adds risk to the Company. In fact, by making significant additions to infrastructure, the Company will be allowed to recover a return on those investments. An arrangement this favorable to a company could only exist in a regulated environment. As both shareholders and ratepayers benefit from the fact that utilities are very low risk firms, this should be appropriately reflected in the awarded rate of return.

Mr. Rowlett also states, "[b]y authorizing an ROE that is consistent with similarly rated utilities and regulatory jurisdictions, the Commission sends a clear message that investors will be treated fairly as compared to other similar investment opportunities."[10] However, the Commission, in past orders, has consistently awarded lower ROEs than requested by the Company. These lower awarded ROEs, for both OG&E and Public Service Company of Oklahoma ("PSO"), have balanced the interests of both the ratepayers and shareholders, and have allowed each Company to remain financially strong and attract capital on par with companies of similar risk.

[9] Direct Testimony of Donald R. Rowlett P. 12, L 11-12
[10] Direct Testimony of Donald Rowlet P. 13, L16-18

Q: What are your specific responses to Dr. Evans?

A: Dr. Evans states, "[t]he challenge facing the regulator is to find the outcome where the regional utility recovers all costs of production and earns a reasonable risk-adjusted profit, thus ensuring that the utility has full and competitive access to the productive resources (labor, materials and capital) needed for operations."[11] However, in making significant additions to its rate base, OG&E is adding to its overall revenue requirement. Under the rate base rate of return model, the Company will be allowed to recover all of its useful plant investments. This favorable arrangement only exists in the construct of a regulated environment.

As Mr. Rowlett stated in his testimony, Dr. Evans reiterates the same general theme by stating: "ROE models are designed to estimate the return to equity for the utility that would be tolerated by a competitive market."[12] Unlike utilities, competitive firms must constantly endure the weight of competition, which increases their risk. Public utilities are not threatened by competitive forces due to their monopoly status, captive customer base, and minimal substitutes for their services. Utilities are defensive companies, and have lower volatility with respect to the overall market. Ratepayers and shareholders benefit from the fact that utilities are extremely low risk firms, and this should also be reflected appropriately in the Company's awarded rate of return.

[11] Direct Testimony of Dr. Russell R. Evans. Page 4, Lines 8-11.
[12] Direct Testimony of Dr. Russell R. Evans. Page 7, Lines 16-18.

Dr. Evans also states, "[i]t falls to the regulator to determine a reasonable signal via an authorized ROE. This signal in turn determines the allocation of productive resources allocated in the economy to the utility."[13] In Final Order No. 662059 in Cause No. PUD 201500273, the Commission concluded that "the 9.50 percent ROE determined herein is fair, just and reasonable to both ratepayers and OG&E. Further, a 9.50 percent ROE will afford OG&E the opportunity to earn a fair and reasonable rate of return. The Commission has undertaken a concerted effort to balance the interests of both the investor and the consumer and believes that the 9.50 percent ROE will be sufficient to allow OG&E to maintain and support its credit, assure confidence in its financial integrity and allow it to continue to attract capital." The Commission has provided similar language in past rate cases for both OG&E and PSO.

Q: What are your specific responses to Mr. Merrill?

A: As Dr. Evans stated in his Direct Testimony, Mr. Merrill reiterates that, "[s]ignificant investment is necessary each year to keep operations current. The financial community's perception of our ability to earn a fair rate of return drives the cost of funding those capital investments."[14] As mentioned earlier when addressing a similar concern in Dr. Evans' testimony, by making significant additions to its rate base, OG&E is adding to its overall revenue requirement. Under the rate base rate of return model, the Company will be allowed to recover all of its useful plant investments. This favorable arrangement only exists in the construct of a regulated environment.

[13] Direct Testimony of Dr. Russell R. Evans – Page 9, Lines 21-23.
[14] Direct Testimony of Mr. Steven E. Merrill – Page 3, Lines 11-13.

Mr. Merrill also states in his Direct Testimony that "the interests of the customers and the investors should be aligned. In a recent essay, Scott Hempling, a noted regulatory attorney who often advises state utility commissions, observed "Shareholder and ratepayer interests, if legitimate, are not opposites. Shareholders want satisfied customers; customers want healthy companies. In regulating public utilities, the public interest is served when shareholder and ratepayer interests are aligned; that is, when pursuit of the shareholder interest simultaneously advances the consumer interest." Here is what this quote means to me. Customers need and expect reliable service. To provide that service OG&E needs the resources to make that possible. One of those resources is equity investment. Equity and debt investors play a critical role in the financing of utility operations. As stated earlier they experience the variability inherent in business outcomes. In order to attract and retain investment dollars the returns must match investors' market-driven expectations. In the end, customers and investors alike are best served by fair, balanced, and predictable returns."[15] PUD agrees with this statement, but for different reasons than Mr. Merrill suggested. First, the alignment of interests of the Company, its ratepayers, and its shareholders will still be achieved with a more appropriate and lower ROE. This Commission has consistently awarded lower ROEs, and has maintained that the awarded ROE provides balance towards the interests of both the investor and the consumer. Second, this methodology is appropriate in the context of incentive compensation. By meeting the four metrics detailed in the Company's incentive compensation plan, the Company can increase profitability, allow generating facilities to become cheaper to run and maintain, increase focus on increasing

[15] Direct Testimony of Mr. Stephen E. Merrill – Page 4, Lines 19-30

customer needs, and provide a safe working environment. OG&E is a financially strong defensive company, with low risk and volatility, which is a double-edged sword and circular. The Company is relatively insulated from market risk. This should be reflected in a lower awarded ROE. However, as OG&E strives to create a company that has low volatility and is financially strong, programs must be implemented to award employees for meeting these metrics geared to achieve a high EPS, an efficient infrastructure, and safe and reliable service.

Q: What are your specific responses to Dr. Morin?

A: The Commission should not allow recovery of flotation costs. When companies issue securities, they typically hire an investment bank as an underwriter for the securities. Flotation costs generally refer to the underwriter's compensation. Flotation should not be considered for three reasons:

(1) Flotation costs are not actual out-of-pocket costs. Underwriters are compensated through an underwriting spread. This spread is the difference between the price at which the underwriter purchases the shares and the price at which the underwriter sells the shares to investors.

(2) Flotation costs are already built in to the market. Through full disclosure in the prospectus, investors are already aware that a portion of the price they are paying for the shares does not go directly to the company. Investors' decisions to purchase shares include flotation costs. It would be inappropriate for the Commission to give credence to Dr. Morin's inclusion of flotation costs in his analysis.

(3) Dr. Morin's recommended ROE is already above the true required return. It is inappropriate to suggest flotation costs be considered in ROE analysis.

OVERALL RECOMMENDATION

Q: Please summarize the key points of your testimony.

A: According to the Supreme Court decision rendered in *Federal Power Commission v. Hope Natural Gas Company*, risk is one of the most important factors to consider when estimating the cost of equity. OG&E, like any utility, is a firm with very low levels of risk – below the market average. As a result, the Company's true required return on equity must be lower than the required return on the overall market. PUD used three widely-accepted methods, plus market analysis, to estimate OG&E's required return on equity: (1) Discounted Cash Flow; (2) Capital Asset Pricing Model; and (3) Comparable Earnings Model. According to these models, as well as the market analysis, OG&E's true required return on equity is likely less than 8.0%. Awarding an appropriate Return on Equity would allow the Company to remain financially healthy and attract capital under efficient and economical management; however, the awarded return must be commensurate with the actual risk of OG&E. To be fair and reasonable to the Company, and in the interest of gradualism, PUD is recommending a return on equity above OG&E's true required return, rather than a more abrupt move toward the true required return. Each of the models discussed in this Cause uses various inputs and estimates. In addition, PUD analyzed the Company's optimal capital structure, and is recommending the Commission adopt the Company's requested capital structure.

PUD believes that full allowance of STI is appropriate to include in the overall compensation package of OG&E, and its recovery from customers. PUD believes that STI are an important way for OG&E to attract and retain qualified employees. In addition, because the Company's incentive compensation package is not directly tied to financial performance, there is no "trigger" which, if met, would provide incentive payout. Focusing on the entire incentive package benefits both ratepayers and shareholders, as employees are focused on creating a company which is not only financially sound and strong, but also one that is safe, reliable, and has efficient infrastructure in place.

Q: Please state PUD's recommendations to the Commission.

A: PUD requests the Commission accept the following recommendations:

(1) PUD's recommended cost of equity of 8.75%, which is the midpoint, rounded to the nearest quarter percent, in a range of reasonableness between 8.24% and 9.24%;

(2) The Company's proposed cost of debt of 5.32%, and capital structure consisting of 46.7% debt and 53.3% equity;

(3) Full recovery of Short-Term Incentive Compensation in the amount of $17,973,228;

(4) The Company's proposed removal of Long-Term Incentive Compensation in the amount of $5,487,519;

(5) The Company's proposed increase to Payroll Expense in the amount of $3,292,166;

(6) The Company's proposed increase to Pension Expense and related Pension Regulatory Liability in the amount of $44,020,013, and its proposed amortization period of five years, resulting in an annual benefit to customers in the amount of $8,804,003;

(7) PUD Adjustment No. B-2, to increase Materials and Supplies by $299,243 to the 13-month average balance based on the six-month post test year;

(8) PUD Adjustment No. B-3, to increase Coal and Oil Inventories by $1,389,919 to the 13-month average balance based on the six-month post test year;

(9) PUD Adjustment No. B-4, to decrease the level of Gas in Storage by $1,229,162 to the 13-month average balance based on the six-month post test year;

(10) The Company's proposed an adjustment to remove all fuel expenses and purchased power costs for the test year in the amount of $787,820,444 from

operating expense, while leaving $76,402,988 in base rates for cogeneration capacity payments;

(11) The Company's proposed an adjustment for Unbilled Revenue and Over/Under Recoveries amount of net decrease in revenues of $66,803,179;

(12) PUD Adjustment No. B-5, to increase Prepayments Expense by $278,416 to the 13-month average balance based on the six-month post test year;

(13) PUD adjustment H-3 to decrease Outside Services / Attorney Fees by $2,835;

(14) PUD adjustment H-4 to amortize Rate Case Expenses to the actual incurred level of expenses. This adjustment will result in a decrease of $152,230 from the $533,445 per year of Rate Case Expenses requested by OG&E;

(15) PUD adjustment H-5 to remove unnecessary expenses from Rate Case Expenses over two years. This adjustment will remove $10,325 of unnecessary expenses from Rate Case Expenses over two years;

I state, under penalty of perjury under the laws of Oklahoma, that the foregoing is true and correct to the best of my knowledge and belief.

Geoffrey M. Rush

State of Oklahoma

County of Oklahoma

Subscribed and sworn to before me this 2nd day of May, 2018.

TISH R. COATS NOTARY # 16005761 EXP. 06/13/20 PUBLIC STATE OF OKLAHOMA

Tish R. Coats
NOTARY PUBLIC

(Seal, if any)

My Commission Number: 16005761

My Commission Expires: June 13, 2020

Oklahoma Gas and Electric Company – Cause No. PUD 201700496

LIST OF EXHIBITS

GMR - 1	*Curriculum Vitae*

Exhibit GMR - 1

Curriculum Vitae of Geoffrey M. Rush
Jim Thorpe Office Building, Room 580, 2101 N. Lincoln Blvd, Oklahoma City, OK 73105
(405) 521-3336, g.rush@occemail.com

Work Experience

Oklahoma Corporation Commission – March 2013 - Present
Energy Coordinator: July 1, 2017 - Present

- Directly supervise a team of Public Utility Division that, as authorized by the State of Oklahoma, regulate electric and gas utility rates, terms, conditions of service, and safety that is in Oklahoma's public interest and serves Oklahoma ratepayers in a fair, just and reasonable manner.

SPP Integrated Marketplace/Day-Ahead Market: March, 2013 - Present

- Monitor all SPP's Day-Ahead processes and create an in-depth work routine of auditing procedures
- Worked with SPP during test markets and transmission rights development
- Monitor the Settlement User Group (SUG), Change Working Group (CWG) and Market Working Group (MWG), Z2 Task Force (Z2TF), Export Pricing Task Force (EPTF)

Bank of Oklahoma – 2011 - 2013
Financial Consultant

- Acquire, retain, and deepen customer relationships.
- Assist the branch to meet sales objectives.
- Proactively meet with clients to discover financial needs and provide recommendations.

JP Morgan Chase/Bank One – 2001 - 2011
Vice President – Investments

- Responsible for developing and maintaining financial and investment relationships, while appropriately managing clients' assets and brokerage accounts.
- Provide advisory and execution capabilities to individuals and families, as well as private and public corporations.

Education

Michigan State University

- Psychology: 1993 - 1997

Professional Licenses

- NASD Series 6: Investment Company Products/Variable Life
- NASD Series 7: General Securities Representative
- NASD Series 63: Uniform Securities Agent State Law
- State of Oklahoma Insurance
- Society of Utility and Regulatory Financial Analysts – Certified Rate of Return Analyst (CRRA)

Professional Training

- Introduction to Energy Trading & Hedging
- Electric Power Engineering Workshop
- Society of Utility and Regulatory Financial Advisors

CERTIFICATE OF SERVICE

I, the undersigned, do hereby certify that on the 2nd day of May, 2018, a true and correct copy of the above and foregoing was sent **electronically**, addressed to the following:

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OKLAHOMA CORPORATION COMMISSION

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	))))))	CAUSE NO. PUD 201700496

Direct Testimony

of

Jason J. Thenmadathil

on behalf of

Oklahoma Gas and Electric Company

January 16, 2018

Q. **Please state your name and business address.**

A. My name is Jason Thenmadathil. My business address is 321 North Harvey, Oklahoma City, Oklahoma 73102.

Q. **By whom are you employed and in what capacity?**

A. I am employed by Oklahoma Gas and Electric Company ("OG&E" or "Company") as the Supervisor of Regulatory Accounting.

Q. **Please summarize your educational background and professional qualifications.**

A. I received a Bachelor of Science degree in Accounting from the University of Central Oklahoma. In 2005, I was employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as a Public Utility Regulatory Analyst, and later was promoted to Coordinator. As a PUD analyst, I testified in various utility cases filed by electric and gas companies, including rate cases and fuel prudence reviews. In March 2010, I joined OG&E as a Senior Regulatory Accountant. In November 2017, I assumed additional responsibilities as the Supervisor of Regulatory Accounting where I oversee the work of members of the Regulatory Accounting group, whose responsibilities are to prepare the minimum filing requirements ("MFR") for rate cases and determine revenue requirements for various rate filings.

Q. **Have you testified previously before this Commission?**

A. Yes. As a witness for OG&E, I previously submitted testimony in Cause Nos. PUD 201500266, 201500273, 201600319, and 201700261.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to sponsor the *pro forma* adjustments to the test year expenses in this Cause and explain why these adjustments are appropriate. The Company utilized a historical test year ending September 2017 with *pro forma* adjustments through March 2018.

PRO FORMA ADJUSTMENTS

Q. **What is the importance of the *pro forma* adjustments in this proceeding?**

A. The Company's proposed *pro forma* adjustments are critical to establish fair, just and reasonable rates. The *pro forma* adjusted level of operations and maintenance ("O&M") expense are necessary to allow the Company to cover operating costs on a going forward basis.

Q. **Why are *pro forma* adjustments to a test year necessary?**

A. The Company makes adjustments to the test year books to design rates which reflect revenue, expense and investment levels the utility expects to experience prospectively. The Company utilizes a historic test year with *pro forma* adjustments reflecting reasonably known and measurable changes. Some of these adjustments include: removal of costs that are recovered elsewhere, costs that did not occur but are or will be normal expenses going forward and cost adjustments that are determined by the Company or past Commission orders to not be the customer's responsibility.

Q. **What are the general categories of *pro forma* adjustments proposed by the Company?**

A. *Pro forma* adjustments fall into one of the following categories:

1) Normalization Adjustments are made to rate base and expenses to offset unusual levels of operations recorded during the test year. An example of such an adjustment would be the use of a 4-year average for short-term incentives to address the variable nature of the expense.

2) Annualization adjustments recognize that some action occurred during the test year that will be ongoing and must be captured on a prospective basis. An example of such an adjustment would be the adjustment to payroll to account for salary increases and employee levels by the end of the *pro forma* period. This annualization is necessary to adjust payroll costs to a level reflecting the *pro forma* salary for the entire year.

3) Out of Period Adjustments consider known and measurable changes that occur outside the end of the test year. An example of such an adjustment would be to decrease pension expenses based on actuarial projections for 2018.

4) Certain adjustments remove costs that are not necessary to provide electric service to customers. An example of such an adjustment would be to remove costs related to donations and contributions.

5) Adjustments to remove costs recovered elsewhere adjust the test year to reflect any cost recovery that occurs outside of base rates. An example of such an adjustment would be to remove fuel and purchased power related costs that are recovered through the Fuel Adjustment Clause ("FAC") rider. This decrease is necessary to ensure that customers are not double charged for fuel costs recovered through a separate recovery mechanism.

INCOME STATEMENT

Q. **What section of the Minimum Filing Requirements contains the adjustments made to the Income Statement?**

A. Section H contains schedules and the supporting workpapers which present the elements of the income statement for the test year and associated adjustments. The income statement calculates operating income by subtracting *pro forma* expense from *pro forma* revenue to arrive at *pro forma* operating income. This level of operating income is compared to the Company's requested level of operating income (the return requirement on the Company's *pro forma* rate base) to arrive at a revenue excess or deficiency for the utility.

Pro Forma Adjustments to the Income Statement

Q. **What *Pro Forma* adjustments will you discuss?**

A. Chart 1 shows each of the expense *pro forma* adjustments and gives a description of each one.

Chart 1 – *Pro Forma* Adjustments to Operating Expense

***Pro Forma* Adjustment**	**Operating Expense Description**
WP H 2-17	Ad Valorem Taxes
WP H 2-18	Pensions and Other Post-Retirement Benefits
WP H 2-19	Active Member Benefits
WP H 2-20	Insurance Expenses
WP H 2-21	Depreciation Expense
WP H 2-22	Payroll Expense
WP H 2-23	Other Compensation Expense
WP H 2-24	Demand Side Management (DSM) Expense Removal
WP H 2-25	Regulatory Expense
WP H 2-26	Bad Debt Expense
WP H 2-27	Storm Rider Expense Removal
WP H 2-28	Southwest Power Pool Expense
WP H 2-29	Amortization of Pension Regulatory Liability
WP H 2-30	SPP Transmission Expense recovered from Load Serving Entities (LSE)
WP H 2-31	Southwest Power Pool Cost Tracker (SPPCT) Expense Removal
WP H 2-32	Long Term Incentive Removal
WP H 2-33	Fuel Adjustment Clause (FAC) Rider Expense Removal
WP H 2-34	Non-recoverable Expense Removal
WP H 2-35	Intracompany SPP Fees
WP H 2-36	Customer Deposit Interest
WP H 2-37	Advertising Expense
WP H 2-38	Other Amortization
WP H 2-39	Rate Case Expenses
WP H 2-40 & H 2-41	Vegetation Management Distribution and Transmission Expense
WP H 2-42	Wind Power Expense Removal
WP H 2-44	Acquisition Adjustment Amortization

Q. **Please explain WP H 2-17, *pro forma* adjustment to Ad Valorem Taxes.**

A. This adjustment increases property taxes by $6,729,712. To arrive at this adjustment, the Company first calculated a ratio of actual Ad Valorem taxes assessed in 2017 to actual plant and property values at the end of calendar year 2016. This ratio was then multiplied by the *pro forma* level of plant and property included in the rate base to arrive at a *pro forma* level of ad valorem taxes. This *pro forma* includes an adjustment reducing property tax expense by $3,991,760 for capitalized Ad Valorem taxes related to projects under construction that are not included in the rate base.

Q. **Is this methodology for the Ad Valorem Tax adjustment a departure from the Company's methodology proposed in the previous rate case?**

A. Yes. The Company's previous methodology utilized 3-year average increases to Ad Valorem taxes to arrive at a *pro forma* level. The Company believes the current methodology is more reasonable in that it applies a ratio based on actual Ad Valorem taxes assessed for 2017. Since Ad Valorem taxes for 2017 are based on plant and property at the end of the calendar year 2016, applying this ratio to the *pro forma* level of plant and property in the rate base aligns property taxes with the rate base. The ratio also utilizes the most recent property tax assessment provided by the Oklahoma Tax Commission. The *pro forma* level of Ad Valorem taxes is primarily driven by increases to plant in service, most notably the addition of the Mustang Modernization Project.

Q. **Please explain WP H 2-18, *pro forma* adjustment to pension and post-retirement benefits expense.**

A. OG&E has established various employee benefit plans funded by employee and Company contributions. Annually, the Company retains an independent actuary to prepare an actuarial valuation of the pension and retiree medical plans. This valuation determines the net periodic benefit cost which is the annual expense recognized by the Company for generally accepted accounting principles ("GAAP") purposes. For the *pro forma* adjustment, the expense level per the November 2017 actuarial report provided by Fidelity was compared with the actual test year level of pension and other post-retirement benefits expense. The level per the actuarial report was adjusted to only include amounts that would be classified as O&M. The result of this comparison is a decrease to pension and post-retirement expenses of $23,585,487.

Q. **What are the components of this decrease to the pension and post-retirement expenses?**

A. This decrease, as demonstrated on W/P H 2-18, can be separated into 3 components: 1) Reductions in pension expense, 2) Reductions in post-retirement medical, and 3) Reductions in post-retirement life insurance.

Q. **Please explain the decrease related to pension expense.**

A. The decrease related to pension expense results from the difference in the expense level per the November 2017 actuarial report provided by Fidelity and the actual expense level reflected in the test year. Reductions in pension expense have occurred primarily due to reductions in interest cost, expiration of amortization amounts associated with previous plan amendments, and changes between expected and actual returns on pension plan assets. This amounted to a decrease of $13,295,747.

Q. **Please explain the decrease related to post-retirement medical expense.**

A. The decrease related to post-retirement medical expense also results from the difference in the expense level per the November 2017 actuarial report and the actual expense level reflected in the test year. Reductions in post-retirement medical cost have also occurred due primarily to reductions in interest cost, changes due to plan amendments, and changes between expected and actual returns on plan assets. In addition, the Company recently modified its retiree medical supplement program in 2017 for retired members, resulting in further decreases to this expense. In total, these changes amounted to a decrease of $8,746,160.

Q. **Does pension expense and post-retirement medical expense have a tracking mechanism to capture any changes in cost that have occurred over time?**

A. Yes. The difference between actual expenses and the level in base rates is tracked via the Pension Tracker approved by the Commission. Any under or over recovery associated with pension and post-retirement medical expenses are recorded as a regulatory asset or liability respectively. Please see the direct testimony of OG&E Witness Bailey for further discussion on this tracker as it relates to regulatory assets and liabilities.

Q. **Please explain the decrease related to post-retirement life insurance.**

A. The Company recently modified its post-retirement life insurance program, resulting in a decrease to expenses of $1,543,581.

Q. **Please summarize the components of adjustment H 2-18 stated above.**

A. The decrease in pension expenses of $13,295,747, post-retirement medical expenses of $8,746,160, and post-retirement life expenses of $1,543,581 result in the total *pro forma* adjustment amount of $23,585,487.

Q. **Please explain WP H 2-19, *pro forma* adjustment to active member benefits expense.**

A. Active member benefits refer to medical, dental, life, and long-term disability benefits for current employees. This adjustment compares actual test year levels with budgeted levels to arrive at a reasonable expense level going forward. Similar to the previous adjustment, only costs classified as O&M were included. The Company recommends an increase of $1,127,539.

Q. **Please explain WP H 2-20, *pro forma* adjustment to insurance expense.**

A. The Company compared test year insurance expense to actual insurance expenses for policy period 2017/2018 using information provided by the Company's insurance brokers. The difference between the test year and projected levels were recorded as a *pro forma* adjustment to decrease expenses by $53,337.

Q. **Please explain WP H 2-21, *pro forma* adjustment to depreciation expense**

A. This adjustment increases depreciation expense to account for the increased level of plant requested in this case as well as new depreciation rates. The Company requests an increase of $75,029,649 to depreciation expense. Please see the direct testimony of OG&E Witness Spanos for the reasoning behind the new depreciation rates.

Q. **Please explain WP H 2-22, *pro forma* adjustment to payroll expense.**

A. This adjustment is designed to capture employee compensation levels at the end of the *pro forma* period. This adjustment consists of three parts. First, payroll expense was annualized based on the number of employees and their associated wage levels as of the end of the test year. To accomplish this, the Company calculated the hourly rates of each individual employee at OG&E, and multiplied those hourly rates by the number of hours worked per year. This adjustment has the effect of capturing a full year of payroll for the additional employees hired into the Company during the test year and eliminating the payroll of employees who left the Company during the test year. For the second part, this adjustment increased payroll to account for raises employees will receive at the end of 2017. This was accomplished by multiplying the payroll levels by a historical 4-year average of raises. This amounted to an approximate 3% increase. For the third part, a calculation was made to estimate changes to payroll expenses occurring from the end of the test year to the *pro forma* period resulting from hires and retirements. This calculation alone resulted in a decrease to payroll of approximately $2.4 million. The result of all the calculations mentioned above result in an increase to payroll expenses of $4,348,660. An additional adjustment of $348,989 is also made for payroll taxes related to the additional expense level, resulting in a total *pro forma* adjustment of $4,697,649 Please see the direct testimony of Patricia Ruden for the justification of total employee compensation levels.

Q. **Is this methodology for the payroll adjustment a departure from the Company's previously recommended methodology to calculate *pro forma* payroll in the prior rate case?**

A. Yes. This adjustment has several components that are different from the previous methodology. First, payroll expense was annualized based on an analysis of each individual employee rather than annualizing the expense from the last 2 week pay period. This allows the Company to remove any employees who have been terminated or retired on the last day of the test year and exclude those employees in the payroll calculation.

Q. **What other components of the payroll adjustment are different than the previous case methodology?**

A. This adjustment also reflects a projection of hires and retirements that will occur through the end of the *pro forma* period. This projection is based on a 4-year historical average of hires and retirements, and also uses a 4-year average of the salaries of hires and retirees to calculate the amount of payroll expense to adjust through the *pro forma* period.

Q. **Will this adjustment be updated with actual payroll information through the end of the *pro forma* period?**

A. Yes. The Company would recommend updating this adjustment with actual payroll information as of March 2018. By utilizing March 2018 information, the projections for salary increases as well as hires/retirements would no longer be necessary since the actual employee levels and actual salaries will be available.

Q. **Please explain WP H 2-23, *pro forma* adjustment to other compensation.**

A. The Company averaged the last four years of short-term and other compensation to arrive at a level of other compensation that captures both upward and downward swings in incentive costs. To arrive at the expense level, the ratio of expense to total payroll was applied in order to remove the capitalized amount. When payroll taxes are included, this results in a decrease to operating expenses of $2,247,885. Please see the direct testimony of OG&E Witness Ruden for further discussion on short term incentives and overall compensation levels.

Q. **Please explain WP H 2-24, *pro forma* adjustment related to demand programs and energy efficiency expenses for Oklahoma and Arkansas.**

A. This adjustment removes costs related to the Oklahoma Demand Program Rider ("DPR") and the Arkansas Energy Efficiency Cost Recovery ("EECR") Rider. These costs are recovered through ongoing rider mechanisms and should therefore be removed from base rates. This adjustment decreases O&M by $43,193,100.

Q. **Please explain WP H 2-25, *pro forma* adjustment to regulatory expenses.**

A. This adjustment has three components. First, the Company normalized regulatory expenses using a 2-year average for various expenses in the Oklahoma jurisdiction excluding rate case expenses. This increases operating expenses by $41,934. Second, the Company removed the Annual Public Utility Assessment Fee ("APUAF") in the amount of $2,316,326 since the APUAF fee is recovered through a surcharge on customer's bills. Finally, any remaining amortization approved in the previous Oklahoma rate case was removed since those amortizations will expire when new rates are effective in the current filing. This would include amortizations associated with rate case expenses as well as various consulting fees associated with prior regulatory cases. This results in a decrease of $916,392. The total for all three adjustments results in a decrease of $3,190,785.

Q. **Please explain WP H 2-26, *pro forma* adjustment to bad debt expense.**

A. The bad debt *pro forma* adjustment includes cost for uncollectible revenues the Company will experience, net of the fuel component of the customer's bill. This adjustment is made to reflect the expected increase in bad debt not associated with fuel. The fuel component of bad debt flows through the Fuel Adjustment Clause ("FAC"). The Company used a four year average uncollectible rate and multiplied it by the *pro forma* revenues net of fuel to arrive at a new bad debt expense level. This adjustment increases operating expense by $33,826.

Q. **Please explain WP H 2-27, *pro forma* adjustment to storm amortization.**

A. The Company removed all storm amortization expenses included in the test year. These storm amortization expenses resulted from prior storm expenses that were deferred to a regulatory asset account and are currently being recovered through the Storm Rider. The base rate level of storm expense remains at $2,739,595, which was the Commission approved level from the previous rate cases. The total adjustment to storm expense is a decrease of $8,513,168.

Q. **Please explain WP H 2-28, *pro forma* adjustment to Southwest Power Pool ("SPP") related expense.**

A. This adjustment results from updated SPP and NERC fees, including the SPP Schedule 1-A Administrative fee. OG&E proposes an increase to operating expenses of $1,752,620 to account for these costs.

Q. **Please explain WP H 2-29, *pro forma* adjustment related to the amortization of the pension regulatory liability.**

A. As shown on WP H 2-29, the pension tracker is expected to result in a liability of $37,653,189 at the end of the *pro forma* period. This amount, along with a contributory life insurance liability of $4,718,962, results in a total regulatory liability of $42,372,151. The Company proposes this amount be returned to customers over a 5-year period, resulting in a reduction to expenses of $8,474,430.

Q. **Please explain WP H 2-30, *pro forma* adjustment to transmission expenses recovered from load serving entities ("LSE's").**

A. This adjustment coincides with rate base adjustment B 3-12. The revenue requirement associated with regionally allocated transmission plant and expense will be assigned to other LSEs around the SPP. This adjustment reduces operating expenses for O&M expense, administrative and general expense, depreciation, and taxes other than income related to those regionally allocated transmission projects. Similar to WP B 3-12, the percentage allocated to other LSE's was derived from the FERC Transmission Formula Rate True-Up Adjustment for the most current 2016 rate year filing. This *pro forma* adjustment is a decrease to expenses of $44,721,489.

Q. **Please explain WP H 2-31, *pro forma* adjustment for SPPCT Rider Expenses.**

A. This adjustment removes SPP costs that are recovered through the SPPCT Rider. This results in a decrease to O&M of $73,616,064. Also, SPP fees directly charged to certain customers were also removed, which amounts to $571,776. The total *pro forma* adjustment is a decrease of $74,187,840.

Q. **What type of cost does the SPPCT recover from ratepayers on an annual basis?**

A. This rider recovers the cost associated with SPP Schedule 11 Base Plan fees, which are charged by the SPP for OG&E's allocated share of the transmission investment made by third parties. The rider also includes a reduction for SPP revenues and credits. SPP's regional cost allocation mechanisms have been approved by the Federal Energy Regulatory Commission ("FERC"). SPP utilizes FERC approved transmission rates and cost allocation methodologies to charge OG&E for costs associated with transmission projects constructed and owned by other transmission owners.

Q. **Please explain the annual re-determination of the SPPCT factor.**

A. Per the SPPCT tariff approved in last rate case filed under Cause No. PUD 201500273, the Company shall submit re-determined SPPCT rates to the Commission Staff for implementation on the first billing cycle of April each year. The Company is required to submit a set of workpapers sufficient to document the calculations of the re-determined SPPCT rates. This documentation has been submitted to the Commission Staff, and re-determined factors have been approved and implemented accordingly. Additionally, please see the testimony of OG&E witness Greg McAuley which describes OG&E's role as a member of the SPP, including the Company's participation in the stakeholder process.

Q. **Please explain WP H 2-32, *pro forma* adjustment to remove long-term incentives.**

A. This adjustment removes the Company's long-term incentives paid to employees. While the Company believes this cost should be shared by customers because of the operational and financial benefits that customers receive as a result, the Company is not requesting rate recovery of these costs in this Cause. The result of this removal is a reduction to expenses of $5,487,519.

Q. **Please explain WP H 2-33, *pro forma* adjustment to remove Fuel Adjustment Clause ("FAC") related costs.**

A. This adjustment removes all expenses recovered through the FAC Rider. This would include costs associated with fuel, purchased power (with the exception of cogeneration capacity payments), and air quality control systems ("AQCS") costs. This adjustment removes $787,820,444 from operating expenses while leaving $76,402,988 in base rates for the cogeneration capacity payments.

Q. **Please explain WP H 2-34, *pro forma* adjustment to remove certain non-recoverable items.**

A. This adjustment removes costs related to entertainment, gifts, donations, sponsorships, and shareholder related legal expenses that were included in various "above the line" FERC accounts (accounts included in the test year). OG&E proposes a decrease to operating expenses of $599,240.

Q. **Please explain WP H 2-35, *pro forma* adjustment to remove intracompany SPP fees.**

A. An adjustment is necessary to eliminate expenses received by OG&E from the SPP for network transmission service provided by OG&E. The FERC has provided guidance to the industry that while these are intra-company charges and are normally eliminated in accordance with GAAP, they should be reflected gross in the FERC Form 1. This adjustment decreases expenses by $167,927,025. The removal of the associated revenues is reflected in the revenue adjustments supported by OG&E Witness Knight.

Q. **Please explain WP H 2-36, *pro forma* adjustment to customer deposit interest.**

A. This adjustment includes interest expense based on year-end customer deposits that are deducted from rate base as non-investor supplied capital. This expense is not included in the utility operating expense category as reported in FERC Form 1 and should therefore be included in the revenue requirement calculation. This adjustment is consistent with the Commission's treatment of interest paid on customer deposits in prior utility rate case proceedings. This results in an increase of $1,107,217.

Q. Please explain WP H 2-37, *pro forma* adjustment to remove certain advertising expense.

A. Title 17, Section 180 of the Oklahoma Statutes defines the advertising expenses that may be included by a public utility in its operating expenses for ratemaking purposes. OG&E excluded expenses that did not meet the statutory definition. This results in a *pro forma* adjustment reducing expenses by $1,659,342.

Q. Please explain WP H 2-38, *pro forma* adjustment to include other amortization.

A. This adjustment consists of three components. First, various amortization amounts that have been approved in previous Commission orders were included in the calculation of the revenue requirement. This includes the amortization on the regulatory asset associated with stranded customer meters and the Smart Grid Web Portal, the regulatory asset associated with the Red Rock power plant, and the regulatory asset associated with Retail Transmission AFUDC. While these amounts are recorded as depreciation expense on the Company's books, a separate *pro forma* adjustment is necessary to include these amounts in the revenue requirement as these amounts are not reflected in *pro forma* depreciation rates. This amounts to an increase of $7,236,765. For the second adjustment, the pension regulatory liability amortization level that was approved in the previous rate case must be removed from the test year, as this amortization is set to expire around the time new rates will be effective in this rate case. This amounts to an increase of $4,730,420. For the third adjustment, amounts related to the Arkansas jurisdiction were removed. This amounts to a decrease of $674,926. In total, this *pro forma* adjustment increases test year operating expenses by $11,292,259.

Q. Please explain WP H 2-39, *pro forma* adjustment to include rate case expenses.

A. This adjustment consists of two components. First, rate case expenses from Cause No. PUD 201500273 incurred after April 2016 are being requested for recovery in the current case. The Commission Order from the prior rate case stated that "any rate case related expenses incurred after April 30, 2016, should be treated as a regulatory asset subject to review and recovery in the next general rate case." (Final Order No. 662059, p. 72 of 238). This amounted to $557,141. Second, this adjustment includes estimated rate case expenses associated with the current case, which amounts to $509,750. The Company proposes the same treatment approved in the prior rate case, with inclusion of actual cost through the end of the *pro forma* period ending March 2018. Any costs incurred after this time shall be deferred to the next rate case. The Company recommends a two year amortization for both of these amounts. This adjustment increases operating expenses by $533,445**.**

Q. **Please explain WP H 2-40, and H 2-41, *pro forma* adjustments to vegetation management expense.**

A. Both adjustments are increases to the test year to adjust distribution and transmission vegetation management expenses to the level approved by Commission Order #662059 in March 2017 filed under Cause No. PUD 2015000273. These adjustments increased O&M by $6,458,917 and $1,255,357 respectively for a total increase to O&M of $7,714,274 for vegetation management.

Q. **Please explain WP H 2-42, *pro forma* adjustment to wind power expense.**

A. This adjustment removes $333,896 of wind power education expense that was incurred during the test year. Since wind power education expenses are recovered through the Green Power Wind Rider ("GPWR"), the test year expense should be removed.

Q. **Please explain WP H 2-44, *pro forma* adjustment to include acquisition adjustment amortization.**

A. An acquisition adjustment is based on the difference between the purchase price of an asset and its original cost. This *pro forma* adjustment is primarily related to the acquisition adjustment for the Redbud Power Plant. This amortization is the equivalent of depreciation expense for the acquisition premium associated with the plant purchase. This adjustment increases operating expenses by $5,567,337.

Q. **Does this conclude your testimony?**

A. Yes.

In the Matter of:

Application of Entergy New Orleans, LLC, et al

Victor Prep

March 14, 2019

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BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTION R-15-194 AND R-17-504 AND FOR RELATED RELIEF	DOCKET NO. UD-18-07

* *

Deposition of VICTOR PREP, 8055 East Tufts Avenue, Suite 1250, Denver, Colorado 80237-2835, taken at the law offices of DENTONS, US LLP, located at 650 Poydras Street, Suite 2850, New Orleans, Louisiana 70130, commencing at 9:05 A.M., on Thursday, the 14th day of March, 2019.

APPEARANCES:

ENTERGY SERVICES, INC.
(By: Alyssa Maurice-Anderson, Esquire)
639 Loyola Avenue
Suite 2600
New Orleans, Louisiana 70113

- AND -

A. The energy -- The external allocation factors, yes.
Q. All the demand allocators?
A. Yes.
Q. Labor allocators?
A. Those are part -- I don't think the -- The labor allocators are developed within the model and that development would not be any different.
Q. So you're saying you don't think they would need to be updated. They would automatically be updated?
A. Well, those internal allocation factors that are developed with the model, that process need not be changed.
Q. What about customer related allocations? Would those also need to be updated?
A. With the customer billing data, yes.
Q. But -- So if I understand, you're recommending that the outcome of that updated cost-of-service study would not necessarily form the basis of the allocation of the FRP adjustment; right?
A. Could you repeat that question?

Q. You're not saying necessarily the outcome -- The class allocation that results from that updated class cost-of-service study would not necessarily be the basis for allocating the -- the final basis for allocating the formula rate plan adjustment; correct?

A. The -- I hope I'm answering your question. My answer would be we would allocate all operating costs. We would -- The other cost component in the revenue requirement adjustment is the return component. That would be evaluated in whatever fashion the Council evaluates it in this rate case. We would then result in the -- each rate class revenue requirement in total equal to the FRP total revenue adjustment.

Q. So I guess that's what I'm getting at. In this case, the ultimate revenue allocation among the classes that you propose does not match the cost-of-service revenue allocation; correct?

A. The operating -- We need to be more specific. The allocation of operating costs do not match in what way? I'm trying to be on the same --

Q. In other words, the allocation of the cost of service, in your view, may be further adjusted based on altering or adjusting the relative rate of returns for each class?

A. The rates of return like -- The rates of return by class would be a result of this proceeding. And that same process of evaluating the rates of return by class would be done in the each of the FRPs.

Q. Right. I guess what I'm saying is when you evaluate the relative rate of return and you alter them so they don't necessarily match the overall rate of return; correct?

A. Correct.

Q. The result of that is the overall revenues allocated to the various classes does not on an overall basis match the cost of service?

A. They add up as a composite to the total utility cost of service.

Q. But let me ask you. If you -- If they exactly match the cost of service, then the relative rates of return would be the same for every class; correct?

but that I would have percent changes to the cost of service such that those providing higher allocated rates of return might be given larger adjustments to their cost of service accordingly. So it's my judgment and basing my recommendation on the changes to each of the ones in a composite basis to provide the total picture for the utility, for the electric or gas utility.

Q. I'm not sure I followed all that honestly. Are you saying that you tried to look at these to make comparison to what the rate impacts would be or bill impacts would be?

A. Revenue changes, cost-of-service changes. The cost of service is the present revenues level by each class. The cost of me serving residential right now is whatever the present residential revenue is in total. That is the total cost of service right now for residential. So how will I change that for that versus one of the other customer classes? I would make changes across all of the customer classes recognizing those that have much different rates of -- allocated rates of return, try to have changes in those in my recommendations such that I thought the recommendation would be reasonable for all classes to make the total cost of service change that we recommend.

Q. So are you trying to make the percentage reduction revenue similar among classes?

A. Reasonable. I wouldn't say similar. I would say reasonable. In fact, the percent changes for some of the classes that have high rates of return, I've recommended that there be larger changes to their allocated cost of service.

Q. So was there a range of what you consider a reasonable change in -- ultimate change in revenues?

A. Again, there's no standard. There's no ceiling or range.

Q. You just sort of eyeballed it and decided what's reasonable?

A. I don't know if an analyst would say they eyeballed it. They apply what they think is reasonable in the changes to provide the picture that they would base their recommendation on.

Q. But there is no objective standard that you measured these outcomes against?

MR. REED:

Asked and answered.

MR. WILLIAMS:

I'm just -- I'm trying to wrap this up.

THE WITNESS:

I -- No. I said before there is no standard.

EXAMINATION BY MR. WILLIAMS:

Q. To go back to the formula rate plan, as we move forward, would the relative rate of returns for each class remain in effect as they're established in this case?

A. No, I did not say that. In fact, I said they should be reviewed. If I have another 12 months and another revenue adjustment and a picture similar to this and the regulatory body, the decision makers setting the adjusted revenue requirement for each class looks at this, I'm not sure they will take my recommendation per se. But I think they should -- I recommended that they should review those and see how they would apply those in adjusting the cost of service or revenues for each of the FRPs.

Q. So what relative rates of return should ENO start with when it makes its FRP filing?

A. Should ENO start with?

Q. Yes, sir.

A. Well, they should use their judgment same as I had in basing my recommendation. I would make an application if I were in that side or in that party looking at the present cost of service, which is there, the present revenue, seeing what return component I have and how much I would change that class by class, and I would build my recommendation for application in the same way.

Q. Would it be reasonable for ENO to start with the existing relative rates of return that are assigned in this case for a starting point?

A. The existing rates of return in this case would -- whatever the Council decides -- would correspond to -- would be looked -- would be viewed in conjunction with the return component or return cost with the revenue that

REPORTER'S CERTIFICATE

This certification is valid only for a transcript accompanied by my original signature and original required seal on this page.

I, Kathy Ellsworth Shaw, Certified Court Reporter in and for the State of Louisiana, as the officer before whom this testimony was taken, do hereby certify that VICTOR PREP, to whom oath was administered, after having been duly sworn by me upon authority of R.S. 37:2554, did testify as hereinabove set forth in the foregoing 118 pages; that this testimony was reported by me in stenotype reporting method, was prepared and transcribed by me or under my personal direction and supervision, and is a true and correct transcript to the best of my ability and understanding; that the transcript has been prepared in compliance with transcript format guidelines required by statute or by rules of the board, and that I am informed about the complete arrangement, financial or otherwise, with the person or entity making arrangements for deposition services; that I have acted in compliance with the prohibition on contractual relationships, as defined by Louisiana Code of Civil Procedure Article 1434 and in rules and advisory opinions of the board; that I have no actual knowledge of any prohibited employment or contractual relationship, direct or indirect, between a court reporting firm and any party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter; I am not related to counsel or to the parties herein, nor am I otherwise interested in the outcome of this matter.

____
KATHY ELLSWORTH SHAW, CCR, RPR
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BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	)	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-8

Question:

Referencing the allocation methodology Mr. Prep recommends for the allocation of AMI costs, Prep at page 28, lines 4-6, 8-21), please explain:

a. Whether the Electric and Gas AMI Allocation Factors presented in Ms. Crouch's testimony must be updated annually in the Electric and Gas Formula Rate Plans. If so, please describe how the Company would calculate the update.

b. Whether any revision to the development of the allocation methodology or its implementation will be needed in order to utilize it in the future, once AMI is fully deployed and operational. If such revision will be required, please explain how the allocation factor would be developed and applied in such future circumstances.

Response:

a. The allocation factors referenced in the response to ENO 2-7 would not be updated annually.

b. The AMI allocation methodology, as referenced in Docket No. UD-16-04 in the response to ENO 2-7, would not be revised.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	)))))	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-10

Question:

Referencing page 30, lines 9-15 of Mr. Prep's testimony, addressing the class allocation of the electric cost of service, please:

a. Describe in detail the factors considered by Mr. Prep, and how such factors were weighed, in determining what constitutes "reasonable percentage changes to each rate schedule's total revenue…"

b. Describe in detail the factors considered by Mr. Prep, and how such factors were weighed, in determining what constitutes an appropriate target rate of return for each rate class.

Response:

a. and b. No specific algorithm was used to arrive at customer class rates of return on rate base allocated to customer classes. The customer class rates of return would be expected to be varied among the classes, particularly since they were last reviewed in the 2008 rate case. Adjustments to existing customer class rates of return can be gradual, moderated by the existing customer class revenue levels and the objective of minimizing rate shock related to large rate changes. These adjustments to customer class rates of return are in the province of the regulator's judgement in deciding the relative changes among customer classes. The Advisors' analysis puts forth a recommendation showing proposed customer class rates of return and the corresponding changes to each of the nine customer class present revenue levels for the Council's consideration.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	**DOCKET NO. UD-18-07**
GAS RATES PURSUANT TO COUNCIL	**)**	
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

MYRA L. TALKINGTON

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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Exhibit MLT-8	Excerpts from the Deposition of Victor Prep in the matter of Application of Entergy New Orleans, LLC, *et al* (March 14, 2019)

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Myra L. Talkington. My business address is 425 West Capitol Avenue, Little Rock, Arkansas 72201. I am employed by Entergy Services, LLC ("ESL")[1] as Manager, Utility Pricing and Analysis.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony before the Council of the City of New Orleans ("the Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. ARE YOU THE SAME MYRA TALKINGTON WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to several recommendations of Intervenor and Advisors witnesses regarding ENO's cost allocation and rate design proposals. Regarding cost allocation, I respond to the alternatives proposed by Advisors witness Victor Prep and Crescent City Power User Group ("CCPUG") witness Stephen J. Baron for the allocation of ENO's

[1] On September 30, 2018, Entergy Services, Inc. converted to a Louisiana limited liability company from a Delaware corporation and is now Entergy Services, LLC ("ESL"). ESL is a service company subsidiary of Entergy Corporation that provides technical and administrative services to Entergy affiliates, including Entergy New Orleans, LLC.

electric and gas revenue requirements among customer classes. I also address the recommendations of Intervenor and Advisors witnesses regarding the allocation of purchased capacity costs, gas pipeline distribution costs, and adjustments to ENO's proposed revenue requirement, if any. Additionally, I address Mr. Prep's recommendation to increase the amount of production demand costs allocated to interruptible electric service customers in the cost of service study.

Regarding rate design, I respond to the proposals of Mr. Prep and Alliance for Affordable Energy ("AAE") witness Justin R. Barnes to reduce ENO's proposed residential electric customer charge. I also respond to Mr. Prep's recommendation that ENO's declining block rate structure be eliminated. Finally, I address Mr. Prep's and Mr. Baron's proposals related to mitigating the impact of ENO's proposed electric rate change on the Company's Algiers residential customers.

III. ALLOCATION ISSUES

Q5. WHAT ARE SOME OF THE KEY FEATURES OF ENO'S REVENUE ALLOCATION METHODOLOGY?

A. For electric rates, ENO proposed that rates be based on the historic allocation approved by the Council rather than on the results of the cost of service studies. As a result, each rate class initially received an equal percentage base rate increase of 46.1%. Next, for the reasons explained in the Revised Direct Testimony of Company witness Joshua B. Thomas, and to address the disparate effect of the rate change on various customer classes, the Company re-allocated the capacity costs associated with the River Bend 30 and Wholesale Base Load ("WBL") purchase power agreements using an energy-based allocation.

For gas rates, ENO proposed to maintain the currently effective base rate revenue allocations, rather than to follow the cost of service study.

Q6. WHAT MODIFICATIONS DO THE ADVISORS AND CCPUG WITNESSES PROPOSE TO THE ALLOCATION OF THE ELECTRIC REVENUE REQUIREMENT?

A. Both Mr. Prep and Mr. Baron disagree with ENO's proposal to adjust the allocation of River Bend 30 and EAI WBL capacity costs, on the grounds that it does not properly reflect cost causation principles. Mr. Baron does not oppose the manner in which ENO has developed its electric cost of service study (which is limited to what ENO believes are properly considered base rate revenues).[2] However, Mr. Baron recommends that the base rate electric revenue requirement be allocated to customer classes exclusively based on an equal percentage increase, without any further adjustment to the allocation of capacity costs, subject to a "mitigation adjustment" employed to ensure that no class receives an overall increase greater than 2%.[3]

Mr. Prep disagrees with ENO's methodology for developing the cost of service study for electric service, instead proposing inclusion in those studies of what he

[2] Air Products and Chemicals, Inc. ("APC") witness Maurice Brubaker also does not oppose ENO's approach to development of the electric cost of service study. Direct Testimony of Maurice Brubaker at 5.

[3] Direct Testimony of Stephen J. Baron at 25-26.

considers to be ENO's total fixed and variable cost of service, and total revenues.[4] In order to arrive at the final allocation of his total electric revenue requirements, Mr. Prep "varied the customer class before-tax rates of return on allocated rate base for each rate schedule to determine the corresponding total revenue change for each customer group and compared the revenue changes to existing total retail revenue for each customer class."[5]

Mr. Prep indicates that his electric class revenue allocations produce a reduction from current revenues for all customer classes (based on the Advisors' proposed revenue requirement).[6] However, the class revenue allocations shown in Mr. Prep's Exhibits VP-9 (electric) and VP-11 (gas) do not tie to the external cost of service model used by the Advisors to develop their recommended overall revenue requirement.[7] Accordingly, ENO reserves its right to supplement its discussion of the Advisors' recommended class revenue allocations pending receipt of further information from Advisors on the reasons for these differences.

Mr. Prep did not apply any specific standard to determine what constitutes an appropriate customer class before-tax rate of return. See the Advisors' response to ENO Data Request 2-10, attached to my testimony as Exhibit MLT-5. Moreover, he provides no methodology or supporting documentation that facilitates an understanding of how his approach may be accurately duplicated or updated in a transparent, consistent manner in

4 Direct Testimony of Victor Prep at 11-17.

5 Direct Testimony of Victor Prep at 30.

6 Direct Testimony of Victor Prep at 31, Table 5.

7 *See* Exhibit MLT-8, Deposition Excerpts of Victor Prep at pp. 75-82, Deposition Exhibit 1.

the future.[8] Mr. Prep further explained in his deposition that whatever class rate of returns are ultimately adopted by the Council should be considered each class' allocated "cost" of ENO's investments in utility service.[9]

Q7. WHAT IS YOUR REACTION TO THE ADVISORS' REVENUE ALLOCATION APPROACH?

A. While the Advisors' approach of varying class returns is a way of moderating adverse rate impacts to particular classes, identifying these varied class returns as the cost of serving the various customer classes confuses cost allocation and rate moderation principles. ENO's overall weighted average cost of capital in making investments is the cost of serving all its customers. The Advisors, for example, recommend that ENO earn an overall return of 8.93% (including taxes) in order to recover the cost of compensating its investors for the capital they provide in order for ENO to fund utility service and infrastructure. The class returns proposed by Mr. Prep, however, range from 1.28% (residential) to 19.00% (Small Electric, Municipal Building, Master Metered Non-Residential, and Lighting).[10] These differences from the overall cost of capital should be considered to represent efforts to arrive at an assignment of revenue for each class that Advisors believe to be appropriate in order to avoid adverse rate impacts, rather than representing the allocation of a cost-based rate of return to each class. Company witness

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8 *See* Exhibit MLT-8 at pp. 32-38.

9 *See* Exhibit MLT-8 at pp. 25-33.

10 *See* Prep Exhibit VP-9.

Matthew S. Klucher further addresses these matters in his Rebuttal Testimony concerning the cost of service study and the Advisors' proposal for updating allocation factors in connection with the Formula Rate Plan ("FRP").

Q8. WHAT COST ALLOCATION PROPOSAL OF APC WITNESS BRUBAKER RELATED TO ELECTRIC RATES DO YOU ADDRESS?

A. For the most part, it is my understanding that Mr. Brubaker does not take issue with ENO's cost of service study and cost allocation proposals. He does, however, include one recommendation that raises concern. Mr. Brubaker recommends that, to the extent the Council adopts any reductions to the electric revenue requirement proposed by ENO, those reduced amounts should be spread among only "those customer classes whose revenues would be above cost of service under ENO's rate proposal."[11]

Q9. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

A. First of all, ENO does not agree that adjustments to its electric revenue requirement (other than the corrections already identified by the Company) are appropriate, as explained by other ENO rebuttal witnesses. Beyond that, Mr. Brubaker's proposal inappropriately mixes matters regarding the determination of the revenue requirement with matters of cost allocation. The appropriate revenue requirement should be arrived at prior to determining how that revenue requirement is to be applied to rate classes. In this way, the need for mitigation of undue impacts on a particular rate class can be assessed

[11] Direct Testimony of Maurice Brubaker at 15.

from a view of the appropriate revenue requirement as a whole, rather than carving out particular elements of the revenue requirement for special treatment.

Q10. DO YOU HAVE ANYTHING FURTHER TO ADD TO YOUR DISCUSSION OF THE ELECTRIC CLASS REVENUE ALLOCATION ISSUE?

A. ENO continues to believe that its methodology for electric class revenue allocation is reasonable. It is consistent with cost allocation methodologies used in the past by the Council. ENO's adjustment for the allocation of River Bend 30 and EAI WBL purchased capacity costs mitigates rate impacts to residential customers; further, as explained in the Direct and Rebuttal Testimonies of Mr. Thomas, ENO's proposed allocation of these capacity costs maintains the status quo regarding the allocation of those costs, promoting rate stability, and is consistent with the energy-related savings produced by those contracts.

All that being said, ENO realizes that this is an area of ratemaking involving the exercise of a significant amount of judgment and discretion on the part of the Council. Ultimately, the Council should determine a reasonable approach to cost allocation under the circumstances, in the exercise of its discretion.

Q11. WHAT REVENUE ALLOCATION ISSUES RELATED TO THE GAS RATES DO YOU WISH TO ADDRESS?

A. While ENO proposes to maintain the status quo regarding the allocation of gas revenues to the various classes, the Advisors and CCPUG witnesses propose different approaches to the process. Similar to his approach to the electric revenue allocation, Mr. Prep "varied the allocated rates of return for each gas rate schedule, considering the impact on present revenue levels, to determine the corresponding total revenue changes for each gas customer class."[12] Mr. Baron proposes to adjust ENO's revenue allocation to reduce by 25% what he describes as subsidies being provided by gas rate classes whose revenues are above costs. Mr. Baron, however, makes a further adjustment such that no class receives a revenue increase as a result of this case.[13]

As with electric rates, ENO continues to support its methodology, and believes the Council should exercise its discretion to arrive at a just and reasonable revenue allocation for gas customers.

Q12. CAN YOU NOW TURN TO MR. PREP'S RECOMMENDATIONS REGARDING SPECIFIC COST ALLOCATION ISSUES?

A. Yes. Mr. Prep took exception to two specific allocation methodologies ENO utilitized which I will address—the treatment of interruptible demand in the electric cost of service and the allocation of distribution system pipeline costs in the gas cost of service.

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[12] Direct Testimony of Victor Prep at 39, Exhibit VP-11.

[13] Direct Testimony of Stephen J. Baron at 30.

Q13. WHAT IS MR. PREP'S RECOMMENDATION REGARDING THE TREATMENT OF INTERRUPTIBLE DEMAND IN THE ELECTRIC COST OF SERVICE STUDY?

A. As I explained in my Revised Direct Testimony,[14] ENO proposes to exclude interruptible load from the demands used to calculate the Average 12 CP allocation factor in its cost of service study. ENO utilizes this approach because interruptible customers can be curtailed or interrupted at any time, including the time of system peak. Accordingly, ENO can avoid the cost of acquiring additional capacity to serve interruptible demand. ENO excluded 85% of the interruptible/curtailable load in determining the allocation of fixed costs based on average 12 CP (the adjustment to 15% recognized these customers' demand responsibility for reserves).

Mr. Prep contends that, considering the frequency of the actual interruption of these customers, and his calculation of the "value" of interruptible load, a larger amount of demand-related costs should be allocated to interruptible customers.[15]

Q14. WHAT IS ENO'S POSITION CONCERNING MR. PREP'S PROPOSAL RELATING TO ELECTRIC INTERRUPTIBLE CUSTOMERS?

A. ENO continues to believe that its treatment of interruptible customer demand is appropriate. Though Mr. Prep includes information on the number of actual interruptions in his testimony as relevant information, the amount of times an interruptible customer is interrupted is not determinative in considering how costs should be allocated to that

14 Revised Direct Testimony of Myra L. Talkington at 10-11.

15 Direct Testimony of Victor Prep at 47-48, Exhibit VP-12.

customer. Moreover, ENO is not trying to acquire interruptible capacity, or determine a fair market price for such an acquisition. ENO's objective is instead to determine what portion of its embedded production investment and fixed production costs should fairly and reasonably be allocated to an interruptible customer. Basic principles of cost causation support excluding interruptible customers from cost allocations based on contribution to peak demand, when these customers do not contribute to that demand. Having said this, ENO agrees that there is room for exercise of Council discretion on this issue, in light of the evidence presented by ENO, Mr. Brubaker, and Mr. Prep on this matter.

Q15. WHAT IS MR. PREP'S PROPOSAL REGARDING THE ALLOCATION OF GAS DISTRIBUTION SYSTEM PIPELINE COSTS?

A. Mr. Prep disagrees with ENO's proposal to allocate gas distribution system pipeline costs on the basis of class contribution to peak month demand.[16] Mr. Prep contends the allocation should instead include a 50/50 weighting between class contribution to: 1) peak month demand, and 2) the other winter peak season months. ENO continues to believe that its allocation method is appropriate. Gas distribution pipelines are sized to meet peak demand, which is consistent with ENO's proposed 1 CP allocator. This allocator, moreover, has been served the basis for gas rates approved by the Council for many years. At the same time, there is not a single allocation methodology that alone

[16] Direct Testimony of Victor Prep at 48-49.

must be considered the exclusive appropriate basis for the allocation of these types of costs.

IV. RATE DESIGN ISSUES

A. Residential Electric Customer Charge

Q16. WHAT ARE THE KEY ELEMENTS OF ENO'S PROPOSAL FOR THE RESIDENTIAL ELECTRIC CUSTOMER CHARGE?

A. ENO proposes to increase the residential customer from the current $8.07 to $15.53. The current customer charge is less than half of the cost-based customer charge. By moving part way, but not totally to cost of service, ENO seeks to balance cost-based rates with consideration of customer impacts. The Revised Direct Testimony of Mr. Thomas explains that the level of the customer charge proposed by ENO is rough 75% of the percentage reduction from cost of service reflected in ENO's residential rate class allocation.[17] Mr. Thomas also provides policy support for ENO's customer charge proposal. Advisors witness Prep and AAE witness Barnes disagree with ENO's proposal.

Q17. WHAT POSITIONS HAVE THESE OTHER PARTIES TAKEN REGARDING THE RESIDENTIAL CUSTOMER CHARGE PROPOSED BY ENO?

A. The Advisors agreed that an increase in the customer charge was supported and recommended a $10.00 residential customer charge. The Alliance objected to ENO's proposed residential customer charge for several reasons and recommended an $8.13

[17] Revised Direct Testimony of Joshua B. Thomas at 63.

residential customer charge. No other witnesses specifically addressed the residential customer charge.

Q18. WHAT IS THE ADVISORS' POSITION?

A. Mr. Prep recognizes that ENO's full cost-based customer charge calculation "reflects the unit cost of service, customer-related fixed costs, based on the total allocated customer-related fixed costs developed in the embedded cost of service study."[18] He concludes, nonetheless, that ENO's customer charge calculation "does not have a sound basis." He further states that "the increased level should be reasonable and acceptable for residential customers, particularly at lower usage levels, and the stakeholders representing them." Based on this statement, he proposes an increase in the customer charge to $10.00. (Prep at 60). In response to an ENO data request, Mr. Prep added that customer charges greater than $10.00 for residential customers "resulted in higher percent impacts to the low usage blocks and a less favorable comparison with the high usage blocks."[19]

Q19. WHAT IS ENO'S RESPONSE TO MR. PREP'S POSITION?

A. As with many of the issues I address in my Rebuttal Testimony, establishment of the appropriate level of the customer charge involves the exercise of judgment and discretion. However, Mr. Prep's testimony does not reveal what specific factors or considerations lead him to the conclusion that only an increase limited to $10.00, less

[18] *See* Exhibit MLT-6, Advisors' Response to ENO Data Request 2-19.

[19] *See* Exhibit MLT-7, Advisors' Response to ENO Data Request 2-20.

than half the cost-based customer charge, may be considered "reasonable and acceptable." He appears to agree that the allocated customer cost of service per bill represents a basis for the customer charge per bill in the base rate tariff.[20] He further acknowledges that the cost of service analysis supports an increase in the customer charge.[21] These acknowledgements are consistent with ENO's position. Nonetheless, Mr. Prep ultimately disagrees with ENO, on the basis that the increased level should be reasonable and acceptable for residential customers, particularly at lower usage levels, and the stakeholders representing them.

Q20. HOW DO YOU RESPOND TO MR. PREP'S CONCERN REGARDING IMPACTS ON LOW USAGE BLOCKS OF RESIDENTIAL CUSTOMERS?

A. It is true that under ENO's proposal, at low usage levels, some residential customers would experience a rate increase.[22] However, this factor should be balanced against the fact that the current residential customer charge is recovering too small a percentage of the actual fixed costs of serving these customers. To the extent this situation continues, residential customers with larger usage will continue to pay, through an energy charge that included significant fixed costs, the costs of serving other lower usage residential customers.

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[20] *See* Exhibit MLT-6.

[21] Direct Testimony of Victor Prep at 60.

[22] *See* ENO Application Statement AA-5 (residential bill impacts).

Q21. WHAT IS THE POSITION OF AAE WITNESS BARNES REGARDING THE ELECTRIC RESIDENTIAL CUSTOMER CHARGE?

A. Like Mr. Prep, Mr. Barnes believes that the customer charge proposed by ENO is too high, and he recommends instead a customer charge in the range of $8.13 per month.[23] Mr. Barnes argues that ENO's proposal is "extreme" because it is a significant increase over the current customer charge, and because it is relatively high compared to the average customer charge he derives from a survey of other utility companies. Mr. Barnes also contends that ENO's proposed customer charge will discourage energy efficiency, and that ENO's unit cost study inflates the costs appropriately recovered through the customer charge. Finally, Mr. Barnes claims that ENO's proposal will disproportionately and adversely affect low income customers. Company witness Ahmad Faruqui and I will respond to Mr. Barnes' claims.

Q22. WHAT IS YOUR RESPONSE TO MR. BARNES' CLAIM THAT ENO'S PROPOSED CUSTOMER CHARGE IS "EXTREME?"

A. I do not agree that a comparison of the proposed charge to the existing charge, or to customer charges of other utilities, is a reasonable basis to attach such a pejorative label to ENO's proposal. The totality of relevant factors should be considered in judging the reasonableness of the proposal. From the standpoint of the responsibility of residential customers for the cost of customer service, both the current and ENO's proposed charge are understated.

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[23] Direct Testimony of Justin R. Barnes at 21.

As Dr. Faruqui explains, it is the total bill that a customer reacts to in making consumption decisions. Mr. Barnes has not shown that there is a material difference in impact on those decisions whether $15.53 or $8.13 of a residential bill is assigned to the customer charge. What is clear, however, is that Mr. Barnes' proposal departs much farther from cost causation principles than ENO's proposal.

I also disagree with Mr. Barnes' reliance on customer charges of other utilities. The rate-setting policies and principles applicable in those jurisdictions, and the costs of those other utilities, are not before the Council. ENO's customer charge should be judged based on the particular facts, circumstances, and policies applicable to ENO. I would further note that Mr. Barnes' Table 1[24] shows that his "national average" and "ENO comparable" customer charge are above ENO's current customer charge and above the customer charges proposed by Mr. Prep and Mr. Barnes. Furthermore, review of the details of Mr. Barnes' utility customer charge survey[25] shows that numerous utilities around the country have requested and received regulatory approval for residential customer charges well above the $8 to $10 range proposed by Mr. Barnes and Mr. Prep, and at or above the $15.53 level proposed by ENO.

Mr. Barnes' view is only focused on the level of the customer charge itself or the level of increase. Relying on a comparison that only looks at the level of the customer charge or increase of other utilities to justify a customer charge for a different utility will

[24] Direct Testimony of Justin R. Barnes at 12.

[25] Mr. Barnes provided the survey in response to ENO's Data Request AAE 1-1, seeking the workpapers associated with his testimony. *See* AAE 1-1_Fixed Charge Comparisons_Table 12_WP.

inherently restrict every utility from ever achieving a fixed charge that is representative of the individual utility's actual cost to serve.

For additional perspective, consider that the level of customer charge currently approved for Entergy Arkansas, LLC and Entergy Texas, Inc. represents 74% and 73%, respectively, of the customer-related cost derived from the unit cost study in each of their respective rate proceedings. The current customer charge for ENO only represents 38% of the customer-related costs. A customer charge of $10.00 as recommended by the Advisors would only represent 48% of the customer-related costs. A customer charge of $15.53 as proposed by ENO would represent 74% of the customer-related costs.

Q23. WHAT IS ENO'S POSITION REGARDING MR. BARNES' CLAIM THAT THE COMPANY'S CUSTOMER CHARGE WILL DISCOURAGE ENERGY EFFICIENCY?

A. Company witness Dr. Ahmad Faruqui addresses this claim.

Q24. WHAT IS YOUR RESPONSE TO MR. BARNES' CRITICISM OF ENO'S UNIT COST STUDY AS THE BASIS FOR ESTABLISHING THE CUSTOMER CHARGE?

A. It appears that the difference between ENO and Mr. Barnes is to a large part explained by the difference in the parties' views of what costs should be recovered through the customer charge. The Company classifies the costs subject to the customer charge as those costs that are incurred by a utility even if the customer does not impose a demand on the Company's capacity or consume energy. Mr. Barnes, on the other hand, uses an approach that excludes FERC accounts that he considers unrelated to "costs directly associated with connecting a customer to the grid."[26] Mr. Barnes' approach is too restrictive, and ignores the cost allocation of all utility costs that is achieved through a fully-allocated cost-of-service study, while ENO's definition properly captures what may reasonably be considered the fixed costs of serving customers.

Mr. Barnes' formulation, for example, in effect assumes that zero general and administrative costs are expended to support basic customer service functions.[27] Similarly, it effectively assumes that zero costs of customer premises utility installation activities relate to the fixed cost of serving customers. These are not reasonable assumptions. Indeed, his proposal appears to assume that a customer may only want to connect to the grid with no desire to receive a service. Similarly, the other accounts Mr. Barnes' analysis excludes represent the fixed costs of serving customers, which do not depend on or vary with customer demand or consumption.

Mr. Barnes contends that his approach is more consistent with marginal pricing principles, which he believes are more appropriate for determining the customer charge, and he seems to fault ENO for not preparing a marginal cost study.[28] ENO did not perform such a study, however, because it is not required by the Council. The Council instead requires "rates based on an evaluation of fully allocated electric and gas cost of service studies, and alternatives, that include total revenues and allocate total utility costs

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26 *See,* for example, Direct Testimony of Justin R. Barnes at 23-24.

27 Direct Testimony of Justin R. Barnes at 22.

28 Direct Testimony of Justin R. Barnes at 24.

to the various rate classes." Mr. Barnes' approach would not be consistent with these principles, because he excludes from his evaluation of customer-related costs a significant portion of the fixed cost of serving customers. His proposal also suggests that even though the costs he excludes from the customer charge are allocated to the residential class based on the number of customers in the class, customers with higher than average usage should be responsible for a larger share of those costs.

Q25. DO YOU CONTINUE TO RECOMMEND THE COUNCIL ADOPT THE COMPANY'S PROPOSED CUSTOMER CHARGE?

A. Yes. I believe the Company's proposed customer charge is set at a reasonable level, that moves the residential customer charge towards the fixed costs of serving customers. The rate structure should reflect the underlying cost structure and for a long time the customer charge has been significantly less than the cost to serve. Setting rates that provide more accurate pricing will gives customers the proper information to make decisions regarding their energy needs that will maximize the benefits to all customers. As technology continues to rapidly improve it will become increasingly important to have accurate pricing to ensure that the economic value of those options are not distorted simply because electric pricing and electric service costs are not aligned.

Q26. DOES THE FACT THE COMPANY HAS REQUESTED AN FRP REDUCE THE NEED FOR INCREASING THE CUSTOMER CHARGE?

A. No. The proposal to increase the customer charge is to better reflect the cost to serve and to improve equity between customers, which is not addressed by an FRP.

B. Declining Block Rate Structure

Q27. WHAT IS A DECLINING BLOCK RATE STRUCTURE?

A. As customer usage increases, at prescribed usage levels (or "blocks") a declining block rate structure reduces the base rate charged to customers. The declining blocks reflect the fact that the cost to serve customers becomes lower at higher usage levels.

Q28. WHAT IS ADVISORS WITNESS PREP'S RECOMMENDATION REGARDING ENO'S DECLINING BLOCK RATE STRUCTURE?

A. Mr. Prep's testimony recommends that the declining block rate structure for both ENO electric and gas rates should be completely eliminated for all customer classes unless updated load research data can be provided justifying differential treatment for each rate tariff.[29]

[29] Direct Testimony of Victor Prep at 61, 66.

Q29. IS THE DECLINING BLOCK RATE STRUCTURE A NEW ELEMENT OF ENO'S BASE RATE STRUCTURE?

A. No, it is not. ENO has had Council-approved declining block rates for both electric and gas service on an uninterrupted basis for many years.

Q30. HOW COULD THE ELIMINATION OF ENO'S DECLINING BLOCK RATE STRUCTURE ADVERSELY AFFECT HIGHER USAGE CUSTOMERS?

A. Higher usage customers would experience significant rate increases during the winter months. For example, under ENO's proposed rates, the winter period energy charge for usage up to 800 kilowatt hours ("kWh") is $0.07303 per kWh. Above 800 kWh, however, the charge is reduced to $0.05805, approximately 80% of the charge for the initial block. Given the complexity of all of the changes customers will experience as a result of this rate proceeding, the elimination of that expected differential during winter months would likely have adverse customer impacts that it doesn't appear Mr. Prep has considered.

Q31. HAVE THE ADVISORS GIVEN ANY FURTHER INDICATION OF HOW THIS ISSUE SHOULD BE HANDLED, ASSUMING, AS IS THE CASE, THAT ELIMINATING DECLINING BLOCK RATES CAN LEAD TO ADVERSE RATE AND CUSTOMER IMPACTS?

A. Yes. In his deposition, Mr. Prep indicated that he would not oppose an approach whereby the declining block rate structure is not changed in this case. Instead, further examination of the issue by ENO, Advisors, and ultimately the Council, could be conducted independently of this proceeding.[30] ENO also supports such an approach, which could further examine the cost justification for these rates and their proper design.

C. Algiers Residential Rates

Q32. HOW DID ENO PROPOSE TO ADDRESS THE RATE IMPACTS ON ALGIERS RESIDENTIAL CUSTOMERS ASSOCIATED WITH THIS RATE CHANGE?

A. ENO proposed its Algiers Residential Rate Transition (ARRT) Plan in order to moderate the impact of the rate change on Algiers residential customers. As explained in my Revised Direct Testimony and that of Mr. Thomas, the ARRT Plan re-allocates a portion of base rate revenue otherwise assigned to Algiers customers to other classes that would otherwise receive a bill reduction of 10% or more as a result of ENO's proposed rate change. ENO, however, further proposed a second step in the ARRT Plan (effective in September 2021), whereby ENO's overall rates to Algiers customers would increase an additional 3.5%, while at the same time, the level of revenues assigned to the other participating classes will be correspondingly reduced.[31]

Q33. WHAT IS THE POSITION OF THE ADVISORS REGARDING THE ARRT PLAN?

A. Mr. Prep agrees that mitigation of Algiers residential customer rate impacts is appropriate. However, he takes a different approach, which limits the effect of the

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[30] *See* Exhibit MLT-8 at 107-108.

[31] Revised Direct Testimony of Myra L. Talkington at 29-31; Revised Direct Testimony of Joshua B. Thomas at 16-17.

mitigation to ENO's residential class. Mr. Prep's methodology shifts costs between Algiers residential customers and Legacy ENO residential customers, in order to achieve a result that Algiers residential customers experience no change in revenue/bill impact as a result of this case. Mr. Prep further recommends annual rate increases for Algiers Residential customers of no greater than 4%, in order to bring their rates to parity with other ENO residential customers. In his testimony, and additionally in deposition, he indicated that these future adjustments could be made in the context of a rider, through modification of the existing residential base rate tariff, in the course of the three-year FRP, or in future rate actions if necessary.[32]

Q34. WHAT CONCERNS DOES ENO HAVE WITH THE ADVISORS' PROPOSAL TO IMPLEMENT ALGIERS MITIGATION THROUGH A RIDER OR BASE RATE TARIFF MODIFICATION?

A. To the extent the adjustment is made through a standalone rider, the Advisors' approach appears to be similar in concept to ENO's approach, although the Advisors would limit participation in Algiers mitigation to the residential class of customers.[33] However, Mr. Prep did not provide specifics in his testimony or deposition of the specific design of either a rider or a modified base rate residential tariff. Thus, it is unclear from the Advisors' proposal under what terms and conditions a residential rate structure might be designed and implemented under either a rider or a base rate tariff alternative.

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[32] Direct Testimony of Victor Prep at 80-82; *See* Exhibit MLT-8 at 12-20.

[33] *See* Exhibit MLT-8 at 10-12, 19.

Furthermore, ENO in general does not support implementation of Algiers residential customer mitigation through changes to the existing residential base rate tariff. This approach would add significant unnecessary complexity to the tariff design and billing of residential customers.

Q35. DOES THE ALTERNATIVE OF UTILIZING THE FRP TO ACCOMPLISH ALGIERS MITIGATION ALSO RAISE CONCERNS?

A. Yes. The Advisors' position on implementing the Algiers mitigation through adjustments to the FRP is also of concern to ENO. The Advisors again have not provided details on how these adjustments would be incorporated in the FRP. Moreover, as explained in the Rebuttal Testimony of Mr. Thomas, the Advisors' proposal is apparently to cap all future FRP adjustments for Algiers customers at 4%, rather than applying the cap only to adjustments designed to eliminate the current disparity between Algiers and ENO Legacy residential customers.[34] The only exception Mr. Prep would include would be that Algiers customers would pay their full share of the rate change related to NOPS.[35] As Mr. Thomas further explains, ENO believes that such an approach would likely lead to the result that the disparity between Algiers and ENO Legacy residential rates would be exacerbated, rather than eliminated.

ENO continues to believe that a rider, limited to addressing the disparity arising in this case between Algiers and ENO Legacy residential rate impacts, is the most effective,

[34] *See* Exhibit MLT-8 at 16-20.

[35] *See* Exhibit MLT-8 at 20.

transparent, and simple way to implement the Algiers residential customer mitigation, regardless of the customer classes that are chosen to participate in the mitigation.

Q36. DOES CCPUG WITNESS BARON MAKE ANY RECOMMENDATIONS REGARDING ALGIERS RESIDENTIAL CUSTOMER RATES?

A. Mr. Baron does not oppose adoption of the ARRT Plan by the Council. However, similar to Mr. Brubaker's recommendations regarding any revenue requirement disallowances, Mr. Baron proposes that the first $3.325 million of any Council approved revenue adjustment to ENO's requested revenue requirements be used to eliminate the Base Rate Adjustment Rider changes to large customers.[36] In other words, Mr. Baron would dedicate revenue requirement disallowances to eliminating the increased allocations to certain customer classes that are necessary to mitigate Algiers residential rate impacts under ENO's ARRT Plan.

Q37. WHAT IS ENO'S RESPONSE TO THIS PROPOSAL?

A. I have explained above, in response to Mr. Brubaker's similar proposal, why ENO believes it is improper to mix revenue requirement adjustments with cost allocation and rate design adjustments. For the same reasons, adjustments to rates to mitigate Algiers customer impacts should be considered and implemented only after the Council determines the proper ENO revenue requirement.

[36] Direct Testimony of Stephen J. Baron at 27-28.

Q38. DOES THIS CONCLUDE YOUR REVISED DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF Arkansas

COUNTY/PARISH OF Pulaski

NOW BEFORE ME, the undersigned authority, personally came and appeared,

MYRA L. TALKINGTON,

who after being duly sworn by me, did depose and say:

That the foregoing is her sworn testimony in this proceeding and that she knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, she verily believes them to be true.

Myra L Talkington

MYRA L. TALKINGTON

Sworn to and

Subscribed Before Me

This 14th Day of March, 2019

NOTARY PUBLIC

ASHLEY M. SIKORA
MY COMMISSION # 12699437
EXPIRES: November 25, 2026
Saline County

STATE OF NOTARY PUBLIC ARKANSAS

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	**)))))**	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-10

Question:

Referencing page 30, lines 9-15 of Mr. Prep's testimony, addressing the class allocation of the electric cost of service, please:

a. Describe in detail the factors considered by Mr. Prep, and how such factors were weighed, in determining what constitutes "reasonable percentage changes to each rate schedule's total revenue…"

b. Describe in detail the factors considered by Mr. Prep, and how such factors were weighed, in determining what constitutes an appropriate target rate of return for each rate class.

Response:

a. and b. No specific algorithm was used to arrive at customer class rates of return on rate base allocated to customer classes. The customer class rates of return would be expected to be varied among the classes, particularly since they were last reviewed in the 2008 rate case. Adjustments to existing customer class rates of return can be gradual, moderated by the existing customer class revenue levels and the objective of minimizing rate shock related to large rate changes. These adjustments to customer class rates of return are in the province of the regulator's judgement in deciding the relative changes among customer classes. The Advisors' analysis puts forth a recommendation showing proposed customer class rates of return and the corresponding changes to each of the nine customer class present revenue levels for the Council's consideration.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	**)))))**	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-19

Question:

Referencing Mr. Prep's recommendations regarding ENO's customer charge, does Mr. Prep agree that $21.07 accurately reflects the cost-based residential customer charge? If not, what amount should be viewed as reflecting the cost-based residential customer charge?

Response:
$21.07 per bill reflects the unit cost of service, customer-related fixed costs, based on the total allocated customer-related fixed costs developed in the embedded cost of service study. It is one reference to consider in proposing a customer charge portion of a rate tariff. "Cost-based" has several definitions, including marginal costs (short run and long run) and variations combining elements of embedded and marginal costs.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	)	**DOCKET NO. UD-18-07**

Response of: Advisors to the Council of the City of New Orleans ("Advisors")
To the Second Set of Data Requests
Of Requesting Party: Entergy New Orleans, LLC

Question No.: ENO 2-20

Question:

Referencing page 60, lines 12-21 of Mr. Prep's testimony, please explain the specific basis for the conclusion that any customer charge greater than $10.00 for residential customers would be unacceptable to such customers or otherwise considered unreasonable.

Response:

The residential bill comparisons in Statement AA-5 were used to evaluate the impacts among the low usage blocks and high usage blocks with varying combinations of the customer charge and kWh rate. Customer charges greater than $10.00 for residential customers, with the corresponding kWh rate, resulted in higher percent impacts to the low usage blocks and a less favorable comparison with the high usage blocks.

In the Matter of:

Application of Entergy New Orleans, LLC, et al

Victor Prep

March 14, 2019

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BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTION R-15-194 AND R-17-504 AND FOR RELATED RELIEF

DOCKET NO. UD-18-07

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Deposition of VICTOR PREP, 8055 East Tufts Avenue, Suite 1250, Denver, Colorado 80237-2835, taken at the law offices of DENTONS, US LLP, located at 650 Poydras Street, Suite 2850, New Orleans, Louisiana 70130, commencing at 9:05 A.M., on Thursday, the 14th day of March, 2019.

APPEARANCES:

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- AND -

loud, answers yes or no, verbal answers are needed, not shakes of the head or nods, etc. And if I ask you a question that's unclear to you, please ask me to restate it and I'll try to do a better job with it.

A. I will.

Q. Very good, sir.

I want to start -- The first topic I want to address, Mr. Prep, is the rates for the Algiers residential customers. Do you have your testimony with you today?

A. I do.

Q. And the portion of your testimony that relates to it, I believe, starts on page 80. All right, sir. Page 81, line 3, you say the -- And, by the way, in Exhibit VP-15, you've recommended a way to adjust the initial rate change for Algiers residential customers; is that correct?

A. Exhibit 15?

Q. VP-15.

A. Let me just -- I do have those exhibits handy. Let me make sure we're talking about the right one. Yes, that is correct, Exhibit 15.

Q. All right, sir. And the concept here is that based on your revenue requirement, the advisors' recommended revenue requirement, without any further adjustment, it would result in an increase to Algiers customers of approximately $2.9 million; is that right?

A. Using the combined rate for residential that we recommend, the combined rate would result in a 2.985 prior to my proposed or recommended Algiers adjustment.

Q. And so you're recommending to adjust it by essentially moving that $2.985 million from Algiers customers to the other ENO residential customers; correct?

A. To the legacy, yes, the other residential, which is the legacy customers, that 2.985.

Q. All right. And then you would over a period of time adjust the rates for the Algiers customers and legacy customers to remove that differential; is that right?

A. The combined rate would not be changed. The adjustment would be applied between the Algiers and legacy with a maximum adjustment that we recommended.

Q. And eventually there would be no disparity or no difference between the rate paid by Algiers customers and other legacy ENO customers; correct?
A. I'm assuming that would happen over a period of years.
Q. So in concept, your proposal is similar to the proposal ENO made for mitigating residential Algiers rate impacts; is that correct?
A. I believe you'd have to go a little further when you said "similar." Could you be a little more specific in your meaning of similar?
Q. In the sense of both you and ENO adjust the rate impacts of Algiers customers, initially receive no rate change as a result of this case, then over a period of time, their rates would be increased to eliminate the differential between Algiers and ENO legacy customers?
A. In that sense similar, yes.
Q. On page 81, line 3, you say, Algiers -- The revenue adjustment for the Algiers customers could be structured as a

rider tariff mechanism? (As read.)
A. I think the operative words would be "could be." I didn't recommend or insist on a specific mechanism for the adjustment.
Q. So would you support making this adjustment as a rider?
A. After I reviewed the rider to see that it accomplished this and any other aspects did not impede what we would want to see for the residential tariff and other tariffs.
Q. How would the rider be designed?
A. The rider would accomplish the adjustment in the way that you just summarized. If it were a rider applicable to residential or, as I said, the mechanism could be accomplished in other ways within the tariff or with other revisions. I'm not certain exactly what specificity you're looking for.
Q. Well, let me stick with the rider. It would simply adjust for the disparity between the Algiers customers and ENO legacy customers and would not take into account any other costs or changes; is that right?
A. It would -- It would function in the way that I had provided it in Exhibit 15 -- or

let me make sure I'm on the right exhibit reference -- Exhibit 15.

Q. Well, Exhibit 15 doesn't really describe how it works going forward, does it?

A. It does describe when the combined rate produces a change for residential that the adjustment to Algiers with a -- I had a recommended maximum adjustment of 4 percent, that that would be applied between legacy and Algiers. I'm not sure what more description you're looking for.

Q. And that would take place every year until there was no longer a difference between the Algiers and legacy residential rate, that 4 percent change?

A. With the next revenue -- When you said "every year," I would say with each revenue adjustment with the provision, as I think I'm sure I had mentioned, that in the year -- that if, in fact, the NOPS revenue requirement is in effect, that that year would not probably have this adjustment. We would have to see how that came out. But I think that provision was also mentioned in an e-mail adjustment, and we concurred if that would be the case, we would probably bypass that revenue adjustment.

Q. If not a rider, what form would the adjustment for Algiers customers take?

A. It could be within the tariff. Without having written a specific adjustment procedure, I could say that it could be done within a tariff.

Q. How would that work?

A. I didn't -- And I didn't --

MR. REED:

Mr. Williams, I'm going to object to form. You're really calling for speculation since he did not in his testimony lay out the specifics of a rider, and what you're asking him to do essentially is to come up with a design for a rider here.

MR. WILLIAMS:

Well, that's fine.

EXAMINATION BY MR. WILLIAMS:

Q. I'm asking what you know, Mr. Prep.

A. And I am trying to be responsive, Mr. Williams.

Q. Sure.

A. In other words, I'm recommending that the form of that adjustment between legacy and Algiers residential customers take that which I had recommended in Exhibit 15. That form would be applied to succeeding revenue adjustments with the maximum. And that form could be explicit and done in proper form within a separate rider tariff or this tariff. I left that to be done in specific form when we got to a compliance filing or a settlement or whatever later.

Q. All right. Do you have any further thought on how the adjustment would be made if it was part of the formula rate plan process?

A. The formula rate plan process would provide a total residential revenue change and the total residential revenue change would be similar in application to the adjustment as what I have described in Exhibit 15.

Q. So would it stand apart from the other formula rate plan rate adjustments?

A. Are you -- When you say "other," you mean to the other rate classes other than residential?

Q. Let me try to be more concrete. I

mean, say there was a 5 percent increase called for by the formula rate plan, not considering this mitigation issue. How would the Algiers revenue adjustment affect that increase for Algiers customers and legacy residential customers?

A. The Algiers customers would have, as I recommended, a maximum of 4 percent. So if it were a total 5 percent change, whatever the revenue adjustment would be, the maximum of 4 percent would be applied to Algiers and the total residential revenue change would be affected with the remainder.

Q. So who would pay the remaining 5 percent that the Algiers customers didn't pay -- I'm sorry -- the remaining 1 percent. I posited a 5 percent increase. You said that Algiers would be capped at 4 percent?

A. Well, again, using the same format as Exhibit 15, we would have a revenue change, a revenue level, and we would, as I recommended, apply a maximum of 4 percent increase in Algiers. The remaining dollars of the revenue change would be implemented with the legacy customers.

Q. Okay. So what if the FRP increase were only 2 percent? How would the Algiers customers be treated in that scenario?
A. The Algiers customers would be implemented with no more than 4 percent change, increase.
Q. So they'd get a larger increase than the FRP increase in that instance?
A. Than the -- You had suggested or -- a scenario where there would be a 2 percent residential increase?
Q. Yes.
A. Algiers customers would have, again as I recommended, a maximum of 4 percent and the remaining portion of the adjustment would apply to the legacy customers.
Q. So how would these adjustments be carried out mechanically in terms of tariff terms or FRP terms?
A. I think you've already asked that.
Q. Well, I asked that about the rider. I'm asking that about the FRP now.
A. The FRP would result in revenue adjustments per class and the residential revenue adjustment would take us to the

scenarios that you just posited.
Q. All right. If there were a FRP decrease adjustment, what would be the outcome for Algiers customers and legacy ENO customers in that scenario?
A. I would still posit a maximum 4 percent or recommend a maximum 4 percent increase in that annual revenue adjustment to Algiers and the balance be applied to legacy.
Q. So let me ask you this. If ENO's proposed rider for carrying out Algiers mitigation, if it was changed to be -- to impact only legacy ENO residential customers and Algiers residential customers, would that approach work for what you're trying to accomplish?
A. If -- Without seeing the -- If the final result or the exact format, if the concept and calculation as applied in Exhibit 15 were carried through between Algiers and legacy residential customers, then that apparently would accomplish my recommendation.
Q. Are you ready to continue?
A. Yes. Sorry.
Q. No problem.

Would Algiers customers bear their full share of the rate change related to NOPS?

A. All other things being equal, whatever that expression is, I would expect all residential customers would bear the share of NOPS. That was a provision, an exception in the application of the adjustment in my recommendation.

Q. So that wouldn't -- that particular rate change would not be subject to the 4 percent cap, for example?

A. Yes. I did make that provision, as I recall, in my testimony.

Q. What about changes in rates to recover advanced meter infrastructure investment? Would Algiers --

A. I made no other exception.

Q. Just NOPS? That's the only exception?

A. Yes.

Q. Let me ask you some questions about decoupling. I think that's on page 78 to 80 of your testimony. Let's see. Page 9.

MR. REED:

Did you say page 9?

MR. WILLIAMS:
Yes, sir. Well, bottom of page 8. Sorry.

EXAMINATION BY MR. WILLIAMS:

Q. You state there, I also recommend that the decoupling adjustment be calculated on an allocated basis similar to the advisors' decoupling proposal offered previously rather than on a revenue requirement by customer class as proposed by ENO. (As read.)

Can you give us more of a detailed explanation of what you mean by that on an allocated cost basis?

(Whereupon Ms. Tournillon enters the proceedings.)

THE WITNESS:
I believe in my additional testimony pages that you've mentioned earlier, I might have a further explanation, but I can summarize it to say that the recommended decoupling adjustment would be an allocation of revenue requirements similar to that done in the rate case here. So that that would differ in contrast to the results of the rate case

A. The energy -- The external allocation factors, yes.
Q. All the demand allocators?
A. Yes.
Q. Labor allocators?
A. Those are part -- I don't think the -- The labor allocators are developed within the model and that development would not be any different.
Q. So you're saying you don't think they would need to be updated. They would automatically be updated?
A. Well, those internal allocation factors that are developed with the model, that process need not be changed.
Q. What about customer related allocations? Would those also need to be updated?
A. With the customer billing data, yes.
Q. But -- So if I understand, you're recommending that the outcome of that updated cost-of-service study would not necessarily form the basis of the allocation of the FRP adjustment; right?
A. Could you repeat that question?

Q. You're not saying necessarily the outcome -- The class allocation that results from that updated class cost-of-service study would not necessarily be the basis for allocating the -- the final basis for allocating the formula rate plan adjustment; correct?

A. The -- I hope I'm answering your question. My answer would be we would allocate all operating costs. We would -- The other cost component in the revenue requirement adjustment is the return component. That would be evaluated in whatever fashion the Council evaluates it in this rate case. We would then result in the -- each rate class revenue requirement in total equal to the FRP total revenue adjustment.

Q. So I guess that's what I'm getting at. In this case, the ultimate revenue allocation among the classes that you propose does not match the cost-of-service revenue allocation; correct?

A. The operating -- We need to be more specific. The allocation of operating costs do not match in what way? I'm trying to be on the same --

Q. In other words, the allocation of the cost of service, in your view, may be further adjusted based on altering or adjusting the relative rate of returns for each class?

A. The rates of return like -- The rates of return by class would be a result of this proceeding. And that same process of evaluating the rates of return by class would be done in the each of the FRPs.

Q. Right. I guess what I'm saying is when you evaluate the relative rate of return and you alter them so they don't necessarily match the overall rate of return; correct?

A. Correct.

Q. The result of that is the overall revenues allocated to the various classes does not on an overall basis match the cost of service?

A. They add up as a composite to the total utility cost of service.

Q. But let me ask you. If you -- If they exactly match the cost of service, then the relative rates of return would be the same for every class; correct?

A. There's -- There is no reason -- There has been no experience that I've seen in the result of any studies of allocation of cost of service where they were identical to the total utility cost. And adjustments can be made and should be made and will be made to the individual rates of return to establish the cost of service applicable to that customer class.

MR. WILLIAMS:
I have to object to the responsiveness of the answer.

THE WITNESS:
I'm trying to get -- Without, you know, being misunderstood, I'm trying to give you my total thought on the question that you posed.

EXAMINATION BY MR. WILLIAMS:

Q. My question is if the class cost of service was followed beginning to end, all the classes would pay revenues that equals the overall rate of return; correct?

A. In total, the composite provides the total utility rate of return.

Q. I'm talking about the classes.

A. In the classes.
Q. If the overall rate of return is 9 percent --
A. Right.
Q. -- 10 percent --
A. Right.
Q. -- then each -- If you're following cost of service, each class's revenues will give a 10 percent rate of return?
A. If you're following cost of service is, I think, where the confusion lies. The cost of serving has -- which is the revenue collected from any class, is built on what is the return being provided from that class. So I -- My cost of serving any class is -- implies that the return in that class is X percent providing me the revenue which, by definition, is the cost of serving that class and at that period.
Q. Okay. So you're saying if the overall rate of return equity is 10.5 percent, then a cost of serving this class does necessarily include a return on equity of 10.5 percent? Is that what you're saying?
A. Yes. There is -- Each class does

not and has not normally provided the same level of return, if you will, of profitability or return on equity that equal the total Company.

Q. So do you agree that return on equity and overall rate of return are costs of the utilities?

A. Yes, they are, to the total utility.

Q. But your position is they can be allocated pretty much in -- based on judgment, in any form or fashion?

A. The cost of service, which is the present revenue and the change to that cost of service, can be set by the regulator for a number of reasons.

Q. So you don't think there -- I mean, typically costs are allocated based on some sort of objective allocation factor; correct?

A. Yes.

Q. Demand, for example?

A. Yes. Operating costs, yes.

Q. But you're saying return should not be subject to that type of analysis or requirement?

A. Return is a cost, an -- a cost of

service for each class that will require the regulator to apply judgment to say, "Here is where the change to the cost of service to that particular class should be," given all circumstances, given all of the considerations that the regulatory body would have looking at class-by-class revenues.

Q. Then why would you bother to allocate rate base based on allocation factors?

A. Well, given the present cost of service and allocations, which in themselves require a lot of judgment and decision on which allocations to use, the present cost of service, the return provided, and the allocations used in the process give the results that the regulatory body would use to say, "We can change the cost of service or the revenue for this class and other classes based on all considerations in the case, and we will change the cost of service by class from this level to this level for each of the classes, such that in composite, the total revenue requirement of the utility is achieved."

Q. But as far as rate base is concerned, rate base is what return is derived

from; right?
A. Yes.
Q. So you're really not following cost of service for rate base when you alter the returns in a -- sort of a subjective judgmental way, are you?
A. I am following cost of service. I guess we're -- To me, that is the cost applied. If I'm accepting a revenue level of X dollars and the allocations as they are applied and agreed to and including the allocations of rate base, then I am, in fact, saying that my now defined cost of service for this class includes this return component as a cost.
Q. So let me ask you this. If a particular class based on cost of service was assigned 10 percent of the revenue requirement -- I'm sorry -- 10 percent of the rate base -- You have that in mind?
A. Ten percent of the rate base?
Q. Yes, sir. Why would cost of service not lead you to conclude that that class should receive 10 percent of the required return on rate base?
A. We're back to identifying what the

change to the return component of the cost should be relative to the change in revenue levels or for cost of service for that class. I do agree that the rate base provides the -- with the -- the return component provides that cost of service, that component of the cost of service.

Q. But you don't believe that the amount of investment that a class is responsible has any bearing on how much return that class should be responsible for?

A. The rate of return by class times the allocated rate base provides the return cost component. That's my understanding of the cost process.

Q. But rate base and investment has a cost, right, itself? The rate of return represents the cost?

A. The return is the cost.

Q. The rate of return is the cost of that investment; correct?

A. The return is the cost. The rate of return on rate base provides that cost.

Q. So if a class is responsible for 10 percent of the investment utility, why is it

not responsible for a proportion of the amount of return on that investment?
A. That's the same way of answering the question of why don't I have the same rate of return by class? We're back to the same question that you mentioned earlier. There's -- Even Bonbright or any of the references don't say that everyone has to have the same profitability. In fact, look at the results of rate proceedings. They're hardly ever uniform.
Q. So you're --
A. It's -- They're all the considerations to set the revenue or requirement or cost-of-service changes by class. What all those considerations are, they would provide the rate of return or the return cost components of the class cost of service.
Q. Let me ask you a different question. What is the objective basis in your view for determining each class's contribution to the overall return on equity?
A. The objective basis?
Q. Yes.
A. We provide a recommendation for changing the cost of service for each class to

the Council. The Council decides on -- for each of the classes such that they add in total to the total utility cost of service, what that should be. We provide a recommendation.

Q. Right. And what do you base your conclusion that a particular class's contribution to ROE is reasonable or appropriate?

A. Based on my conclusion or my recommendation?

Q. No. Based -- Compared to what standard.

A. I did not mention that there should be a specific standard. I may use the same considerations that the regulatory body did in this case, the Council does. In changing the revenue levels by class, I may look at the existing rates of return and see that some that are higher may be moderated greater than those that are not. But there is no standard.

Q. So you don't subscribe to the view like some rate design practitioners that no -- there should be a ceiling on the amount one class's relative rate of return is different from another or a floor? You don't subscribe to that type of approach?

A. I don't ascribe to a standard or a ceiling or a floor.

Q. Take a look at Exhibit VP-9.

A. Okay.

Q. And you have a -- Line 3, you have the relative rate of return to the various classes.

A. Including taxes?

Q. Yes, sir. And explain to me looking at those very -- the rate of returns range from 1.82 percent for residential to 19 percent for municipal building and lighting; correct?

A. Yes.

Q. What are the factors that you took into account in arriving at the conclusions that those were appropriate relative rates of return?

A. I looked at the correspondence between the rates of return and the changes to the allocated cost of service for each class. And I tried to base my recommendation on moderating the changes so that I would not propose or recommend to the Council that one class be significantly different than others, but that I would have percent changes to the cost of service such that those providing higher allocated rates of return might be given larger adjustments to their cost of service accordingly. So it's my judgment and basing my recommendation on the changes to each of the ones in a composite basis to provide the total picture for the utility, for the electric or gas utility.

Q. I'm not sure I followed all that honestly. Are you saying that you tried to look at these to make comparison to what the rate impacts would be or bill impacts would be?

A. Revenue changes, cost-of-service changes. The cost of service is the present revenues level by each class. The cost of me serving residential right now is whatever the present residential revenue is in total. That is the total cost of service right now for residential. So how will I change that for that versus one of the other customer classes? I would make changes across all of the customer classes recognizing those that have much different rates of -- allocated rates of return, try to have changes in those in my recommendations such that I thought the recommendation would be reasonable for all classes to make the total cost of service change that we recommend.

Q. So are you trying to make the percentage reduction revenue similar among classes?

A. Reasonable. I wouldn't say similar. I would say reasonable. In fact, the percent changes for some of the classes that have high rates of return, I've recommended that there be larger changes to their allocated cost of service.

Q. So was there a range of what you consider a reasonable change in -- ultimate change in revenues?

A. Again, there's no standard. There's no ceiling or range.

Q. You just sort of eyeballed it and decided what's reasonable?

A. I don't know if an analyst would say they eyeballed it. They apply what they think is reasonable in the changes to provide the picture that they would base their recommendation on.

Q. But there is no objective standard that you measured these outcomes against?

MR. REED:

Asked and answered.

MR. WILLIAMS:

I'm just -- I'm trying to wrap this up.

THE WITNESS:

I -- No. I said before there is no standard.

EXAMINATION BY MR. WILLIAMS:

Q. To go back to the formula rate plan, as we move forward, would the relative rate of returns for each class remain in effect as they're established in this case?

A. No, I did not say that. In fact, I said they should be reviewed. If I have another 12 months and another revenue adjustment and a picture similar to this and the regulatory body, the decision makers setting the adjusted revenue requirement for each class looks at this, I'm not sure they will take my recommendation per se. But I think they should -- I recommended that they should review those and see how they would apply those in adjusting the cost of service or revenues for each of the FRPs.

Q. So what relative rates of return should ENO start with when it makes its FRP filing?

A. Should ENO start with?

Q. Yes, sir.

A. Well, they should use their judgment same as I had in basing my recommendation. I would make an application if I were in that side or in that party looking at the present cost of service, which is there, the present revenue, seeing what return component I have and how much I would change that class by class, and I would build my recommendation for application in the same way.

Q. Would it be reasonable for ENO to start with the existing relative rates of return that are assigned in this case for a starting point?

A. The existing rates of return in this case would -- whatever the Council decides -- would correspond to -- would be looked -- would be viewed in conjunction with the return component or return cost with the revenue that would exist by class for that FRP. So then it would be to -- it would be the case of making an adjustment to the cost of service based on whatever those differences of return components were.

Q. All right. So my question is if it doesn't go into that exercise, then why isn't it just as reasonable a starting point to begin with the allocations of revenues that result from this case?

A. Because the allocation process, every part of the operating costs have an allocation applied to them and those allocations might change if there are significant changes to usage characteristics. So I would have and expect to have over the FRPs changes in usage characteristics and changes in the allocation of all operating costs. And it would be simply then the process of seeing how those allocations turned out with my new evaluation of cost of service and look at the return cost, and then come up with the revenue requirement by class for that particular FRP.

Q. Right. But if you're going to take

recommended review of the filing?
A. How would --
Q. Is there -- Do you think the need to present a full cost-of-service update and a review of the relative rates of return, these various things you've described, is that feasible in your view in the review period?
A. I think the cost of service -- When you say -- You mean allocated cost-of-service update, I think that's reasonable. I think it's feasible. As long as you're not changing a number of -- As long as it's done consistently, consistent application is feasible. Consistent reviews of the returns by class as they exist each time of the revenue requirement review is done, that's reasonable. What more are you asking?
Q. No. That's fine. I appreciate it.
MR. REED:
Do you need a break?
THE WITNESS:
I could. I could.
MR. REED:
Can we take a five-minute break?
MR. WILLIAMS:

Yes.

(Whereupon a recess was taken.)

EXAMINATION BY MR. WILLIAMS:

Q. Mr. Prep, I have one more question on the Algiers residential rates.

A. Yes.

Q. We talked about the 4 percent cap and you talked about NOPS being the one exception; right?

A. Yes.

Q. So if -- When the Algiers residential customers receive that increased rate to NOPS, does that reset their baseline? In other words, the next time there's a formula rate plan adjustment, that 4 percent cap would be made in comparison to the increased rate for Algiers that includes NOPS?

A. This rate case will have a combined residential rate. There will be an adjustment in the NOPS case applied to all residential classes -- Well, to all customer classes including residential. And whatever that adjustment would be, would be applied percentage-wise or equally to Algiers and to legacy customers. So if it's in excess of --

what I recommend to be the maximum adjustments to bring Algiers' rates in coordination or in agreement or at the same level as legacy, then that would be a difference. They would have a percent different from what I would recommend be the maximum change.

Q. Right. And so once that change is made, the next time there's a formula rate plan adjustment, and there would be an Algiers cap of 4 percent, it would be 4 percent on top of the baseline that includes the NOPS increase; correct?

A. I believe NOPS will be part of the total residential rate, so I -- I mean, when you say "baseline," I'm not sure I understand.

Q. Well, the rate that 4 percent --

A. The rate --

Q. The rate that the next 4 percent is applied to?

A. The next 4 percent applies to.

Q. Okay.

A. Sorry.

Q. No problem.

Let me ask you another question about the formula rate plan. Testimony page

78. Lines 9 through 14, you discuss a provision for ENO proposing known and measurable cost adjustments in the formula rate plan; correct?

A. Yes.

Q. And so my question is -- this statement relates to costs -- could ENO also propose known and measurable adjustments to revenues?

A. So if there is a -- When I say "known and measurable," a revenue would change in respect to a -- or recovering a known and measurable cost or be correlated to a known and measurable cost. If there is a supportable basis to go beyond the FRP evaluation period in making adjustments other than to known and measurable costs that also include revenue, if there, in fact, is a supportable basis for that, or it relates to a cost adjustment and recovery of that, I would expect that could be -- that would be part of what the provision is that I recommended.

Q. Well, let me be a little more concrete. Could ENO make a known and measurable adjustment for the fact that energy efficiency would reduce demand, reduce sales in the period where the known and measurable adjustment is allowed?

A. You're -- That adjustment would be part of the decoupling aspect of the revenue adjustment in the FRP. That is, if I had a reduction in usage, if I had an impact on the allocation factors, they would all be included in the FRP evaluation. And the revenue that would be required and in an adjustment to that revenue that would be required to maintain the approved ROE, would all encompass that change that you described.

Q. Well, let me ask it this way. Let's say you had a thousand -- A utility had a thousand dollar revenue requirement for purposes of the FRP, but it expected its sales to be reduced by 1 percent due to energy efficiency during this known and measurable adjustment period, so it was going to be $10 less. Could it make an adjustment in its FRP or decoupling process to adjust rates to pick up that $10?

A. I understand your question to be directed to the months following the evaluation

A. As we construct the riders.
Q. Right. They include a division of the rider cost among ratepayer classes?
A. For recovery purposes, yes.
Q. So are all your allocations consistent between the way classes are allocated costs in the class cost-of-service study and the way costs are distributed in the riders?
A. The riders -- The riders should recover costs consistent with the way those costs were allocated and revenue requirements result by the classes to which the riders would be applied.
Q. And you believe all your recommendations carried that out?
A. In general, I believe my recommendations were as I just expressed in my response. Could we be more specific?
Q. I'm just asking you. I mean, are there any exceptions where the way a class of cost that's ultimately recovered in a rider is allocated differently in the rider than it's allocated in the class cost-of-service study?
A. If it were applied the way the cost

recovery would be intended with the rider, it would be to recover costs that are allocated there. I don't see a need for exceptions.

Q. So your view is that all the costs in the rider should be allocated exactly the same way in the class cost-of-service study and in the rider design?

A. I think that's the intent of developing the riders, yes.

MR. WILLIAMS:

Let's mark this as Exhibit 1.

(Whereupon Exhibit 1 was marked for identification by the court reporter.)

EXAMINATION BY MR. WILLIAMS:

Q. The court reporter has handed to you what we've marked Deposition Exhibit 1.

A. Uh-huh (indicating affirmatively).

Q. And the top of this is Exhibit VP-9. Do you recognize that?

A. Yes.

Q. And at the bottom, we've included some variances that we've seen between Exhibit VP-9 and the ENO external working model with the advisors' changes. Are you familiar with this issue?

A. Yeah, I'm familiar with it.
Q. And have you been able to research this? And do you have additional information for us on the variances?
A. This was, I think, seen on Friday, last Friday. So it's a few days and I've been here a few days. So I can say that, yes, I have seen it. I am working on it and I do have some initial -- Without a complete -- time to have a complete run-through on the models and what's behind this particular exhibit, I have some initial observations.
Q. Okay. Why don't you share those with us?
A. Initial observations are I took results from the sets of ENO external models, which were, as we used them, a work in progress during the analysis we had in the preparation of my testimony. And what I have concluded thus far is that the external allocation factors and whatever changes that we -- few changes that we had in them, I believe, were applied correctly.
There is a set of internal allocations that those two -- or the sets of

models perform and we went through various
stages in applying adjustments and using the
models. And I believe in those stages, or what
I called sets of iterations in using the
models, I took out, as an example, operating
and maintenance expense or a depreciation, in
other words, a subtotal of the cost of service,
and used those in a separate worksheet to
develop this exhibit.
And what I had discovered so far is
that I believe I might have taken two
iterations back and when I put the external
model results in subtotal form, or in
allocation form, into my work papers to get
this model. So I would have to go back through
the iterations and see exactly what those
differences might be. But I think that set of
initial observations right now is a partial
explanation on the road to doing a complete
workup on that.
So there are -- The totals are okay.
The allocations I found vary some, and they
would have to be completely redone with the
last iteration that we used in the models.
It's a very long and complicated process using

those models. So I believe that's, as I understand it right now, the basis for the variance. We did find other issues with some of the checks we were doing in the model that we may not have removed and we discussed last Friday. But aside from that, I believe that's my understanding right -- so far.

Q. So you're saying in entering some of the class data in your Exhibit VP-9, you're thinking subject to further investigation, you may not have picked up the --

A. The last --

Q. -- correct numbers?

A. I'm sorry. I should let you finish. I apologize.

Q. That's okay. Let me say it again.

It's a matter of picking up the wrong class allocation numbers in creating Exhibit VP-9?

A. The wrong -- Well, I didn't pick up the wrong numbers. I believe that I took the subtotal results from our evolution in using the models that might have been an iteration or two behind. But I took the -- The model results evolve as you keep using the model. So

I used the correct numbers, but probably in the wrong iteration.

Q. All right. So obviously the Company is working on rebuttal testimony. What should we rely on in terms of responding to your positions on the allocations?

A. I took a look at -- Percentage-wise, I didn't -- You know, I think that the Company should -- As soon as I can, weather permitting, get back to continuing the analysis of the differences in my exhibit and what the external models show -- percentage-wise, it's not that major across here. And if I were to finalize or change some of these variances with the small percentages that they have, I would then go back through the process we talked about earlier in your questions to me. And I think right now, with the variances and with my understanding as it exists now, I would come up with a column-by-column allocated cost of service and a recommendation on revenue changes to that cost of service that would probably stand as I have recommended them in my testimony.

Q. Do you have any feel for what the

time frame is on your process?
A. Two or three days probably. These are a comparison. I worked with the model in the last ENO rate case, one megabyte. Now I have two models of electric and two models gas. Each of those are 80 megabytes and they take quite a bit of time without having a big database to manipulate. So it does take a few days to do that process. So I still stand by my estimate. It will take a few days.
Q. Let me ask you another question about how these line up. Keep Exhibit VP-9 there, Deposition Exhibit 1, and take a look at Exhibit VP-4 in your testimony.
A. Okay.
Q. Exhibit VP-4, take a look at the energy efficiency cost recovery column.
A. Okay.
Q. It doesn't seem to match Exhibit VP-9.
A. It doesn't. I agree.
Q. Tell us -- Can you explain that difference?
A. Okay. The -- If you notice in the structure of the customer classes in sequence,

we discovered at some point during our process that in both the electric and gas, the exhibits that were filed had a different order of the customer classes. I caught that in the gas cases and in the electric case with the SSCR, we caught it. But I did not catch it with the EECR column of numbers, such that the total, which is 6 million plus, is exact, residential is exact, but then the columns did have a change because of the reverse sequence of the customer classes.

So in creating Exhibit 9, and in looking at Exhibit 4, when we -- and Exhibit 9 came from my construction of the allocated cost of service, some of those numbers are not in the correct columns. So that I did find only actually in discovery responses and not too long ago.

Q. So Exhibit VP-4 has the correct alignment?

A. Exhibit VP-4 has the correct -- Yes, VP-4 has the correct sequence of numbers.

Q. It appeared like VP-4, the allocations were the same as ENO's allocations of the $6 million. Is that your intent?

A. Yes. We concurred with the allocation recovery of the energy efficiency costs for the EECR that the Company had proposed.

Q. Going back to Exhibit VP-9, I wanted to ask you particularly about -- again, about line 3, ENO required rate of return on rate base including taxes.

A. Yes.

Q. What did you use as the basis for your income tax calculation there?

A. It -- We applied the current income tax rate to the return without taxes, so there was no individual -- It was just the application of the current income tax rate.

Q. State and federal?

A. Yes, the combined income tax rate to include that with rate of return.

Q. So you did not consider Period 2 impacts, for example, for deferred income tax effects that could affect tax expense in your calculation?

A. I believe the cost of service would be correct with the application of the current combined income tax rate on the return. So --

Q. Did you compare your calculations on taxes to ENO's FIT calculation?

A. ENO developed a tax -- separate line-by-line tax calculations. I did not do an individual class-by-class calculation -- or comparison, rather, of the taxes, but I believe applying a combined tax rate to the return provides an appropriate cost of service relative to income taxes.

Q. Well, if ENO identified other elements, such as flow-through impacts of deferred income taxes or return of protected excess deferred income taxes, would you have a problem with including such items in the federal income tax calculation?

A. They may change from test period to test period. The combined income tax into the return calculation would be consistent between one period and the next. I believe that that is an appropriate way to measure the cost of service.

Q. Well, many items change from test period to test period.

A. Yeah.

Q. If your calculation doesn't include

A. Oh, here we go.
Oh, I thought we were on an earlier page. I apologize.
Energy Smart costs would be included in the ROE evaluation, to clarify that sentence.
Q. So how would you rewrite it to clarify it?
A. I would exclude lost contributions to fixed costs and the utility incentive from the ROE evaluation in the FRP.
Q. So you're saying LCFC and the utility incentive would be outside the bandwidth?
A. No. I do not agree with the LCFC adjustment, period.
Q. All right. How about the utility incentive? Would that be outside the bandwidth?
A. Outside -- The utility incentive would be outside -- I would recommend the utility incentive be provided to the utility outside of the ROE evaluation.
Q. But Energy Smart costs themselves would be --

A. Would be included in the ROE evaluation.
Q. So there would not be dollar-for-dollar recovery necessarily of those costs?
A. We would put the Energy Smart costs in there and put them in there for rider recovery.
Q. Right. So there would not be for sure dollar-for-dollar recovery of those costs?
A. For sure that --
Q. I mean, it's yes-or-no question.
A. No. No.
MR. WILLIAMS:
Let's take a ten-minute break. Okay?
THE WITNESS:
Okay.
MR. WILLIAMS:
Very good. Thank you.
(Whereupon a recess was taken.)
EXAMINATION BY MR. WILLIAMS:
Q. Let me ask you a couple of questions, Mr. Prep, about declining block rates. Do you have any sort of general policy

objections to this type of rate structure, or is it more simply the lack of seeing the cost justification that you're looking for?

A. I think the current policy trends in ratemaking expressed in many jurisdictions -- and I think I have that feeling, although maybe not directly expressed by individual councilmembers -- that we should not decrease the price for larger amounts of consumption. And I'm not opposed to that if, in fact, the characteristics of the particular rate, the customers on that rate show that the costs allocated to that customer class for increased usage levels would warrant a change such that the price would decline with additional usage. If we can't see any analysis that shows that the costs for a particular customer class decrease with increased usage, then I think at the current time of ratemaking and in this docket that we should move toward a flat rate as opposed to other alternatives which may be considered in the future. I think that would be the best recommendation at this time.

Q. Have you made any evaluation of impact on customers who do use the higher block rates of taking out that structure?

A. No. I did not do -- I did not have the data. I did not have any of the means to do that cost analysis. I think it can be done. If, in fact, it's possible to support a declining price for high usage, I welcome an evaluation of that analysis.

Q. And those customers, they would definitely incur a rate increase, right, if those declining blocks were eliminated immediately? All in one fell swoop they would incur a rate increase, correct, for uses at that level?

A. There would be if for a usage level the price, instead of being lower, were set on a flat basis. That would be a price that would be higher. But if it were one fell swoop, I think with any rate changes it's important to look at the dollar impact for customers at those usage levels. And if the dollar impact were significant then, again, principles of moderation and gradualism, we might have to move toward less of a declining block structure to acknowledge those principles.

Q. So you've said "move toward" it a

couple of times. Tell me, what do you mean by moving toward that different structure.

A. Posit an example without any references to its accuracy. If it represented a 15 percent change or some exceedingly different change in amount from any other rate impacts, then I would definitely say that should be moderated, that we would reduce the price decline in the declining block structure such that we would moderate such a high change in the bill for those customers.

So with any rate change, it's a movement toward recognizing gradually.

Q. Do you have any particular rate moderation process in mind?

A. No. I would recommend if we do those adjustments on -- And not every rate is a declining block or a significant declining block. There are a few, as I recall. I would encourage an analysis to look at what impacts would be for the highest levels of use to implement a declining block and to have those percentages evaluated by the Company, the Council and whomever, and say we would recommend a change in between the flat rate and the current price in the declining block structure to moderate any change of this magnitude.

Q. Do you know how long the current declining rate structure has been in place for ENO?

A. I would assume for quite a long time.

Q. Is that something that would also be considered in deciding how to move forward with these rates?

A. All rate changes have that consideration, and that includes more dramatic rate changes in structure than the one that we are discussing. The customers who may have experienced that rate and that usage for a long period of time would not expect to see radical changes. And to consider a movement would be a need to make a change reasonable for those long-time customers.

Q. So although your testimony speaks in terms of eliminating those blocks, you -- I take it you would believe it's reasonable to consider a more tempered approach?

A. A movement toward. A movement

toward.

Q. One more thing I wanted to make sure I was clear on. Page 64 of your testimony, and I'm talking about lines 13 to 15, and you're talking about ENO's proposal to expand the MVLMR and MVDRR. And you reference, expand the schedules to all ENO customers. (As read.) I just want to make sure that what we're talking about here is all customers who are able to act as a market valued load-modifying resource or market value demand response resource; correct?

A. Well, I say "qualified."

Q. Right. So not literally all customers?

A. (Witness shakes head negatively.)

Q. And the qualifications would be determined, I assume, by the tariff and by MISO requirements; is that accurate?

A. Yes. Yes, that is accurate.

Q. So going back to the declining block rate structure, are you envisioning that there could be circumstances where we would just flat eliminate those rates all together in this case, as a result of this particular case?

A. When I recommended movement toward,

I meant in implementing rate design changes, you would recognize all of the considerations such as impact on users. The change should be within a range that the Company, the Council and its advisors or any parties involved with that particular tariff would deem to be reasonable.

Q. Would it be reasonable to consider keeping the rates as they are, not changing the rates as a result of this case and embarking on a process with the Council and the advisors to determine how best to deal with these rates?

A. I would not oppose that. In fact, I'm familiar with many jurisdictions where the specifics of rate design are separated out into a subdocket or -- and then a process to follow everything else being settled in the general rate action. So if that process were segmented in the way you described, I would not oppose that.

MR. WILLIAMS:

And I'll pass the witness.

Thank you, sir. Appreciate your patience.

THE WITNESS:

Thank you.

MS. TOURNILLON:

And I do have a few questions.

For the record, Carrie Tournillon here. I'm with Kean Miller. I'm here on behalf of Air Products and Chemicals.

EXAMINATION BY MS. TOURNILLON:

Q. I wanted to circle back to your Exhibit No. VP-9 to your direct testimony. You had mentioned that -- at least with respect to Row 14 for the EECR, that the amounts didn't match up with the actual customer class columns; is that correct?

A. That is correct.

Q. So is that limited to Row 14, or where would the large interruptible service that's currently Column G, where would that fall if you were to correct this exhibit?

A. Line 14, which is labeled or described as EECR and which we discussed earlier would have values for the columns in Row 14, which would be values for each of the identifications for each column that would correspond to the customer class identifications on Exhibit VP-4, the EECR

Column M and lines 11 through 20.

Q. So that would be a zero percent allocation for the LIS?

A. Yes.

Q. And then going back to VP-9, are there -- the explanation that you gave about the customer classes being in a different order, does that affect any of the other rows on VP-9?

A. Not that I'm aware.

Q. So if I'm looking at Column G for large interruptible service, the numbers that are in each of those rows are correct with the exception of Row 14 as far as you are aware?

A. As far as I am aware.

Q. If you could turn to page 47 of your testimony, and here you're talking about the value of interruptible load. Do you agree that regardless of the number -- I'm sorry. I'll let you get there. Let me know when you're ready.

A. I am on page 47.

Q. Okay. So in this section of your testimony you're discussing the -- appear to be discussing the value of interruptible load.

REPORTER'S CERTIFICATE

This certification is valid only for a transcript accompanied by my original signature and original required seal on this page.

I, Kathy Ellsworth Shaw, Certified Court Reporter in and for the State of Louisiana, as the officer before whom this testimony was taken, do hereby certify that VICTOR PREP, to whom oath was administered, after having been duly sworn by me upon authority of R.S. 37:2554, did testify as hereinabove set forth in the foregoing 118 pages; that this testimony was reported by me in stenotype reporting method, was prepared and transcribed by me or under my personal direction and supervision, and is a true and correct transcript to the best of my ability and understanding; that the transcript has been prepared in compliance with transcript format guidelines required by statute or by rules of the board, and that I am informed about the complete arrangement, financial or otherwise, with the person or entity making arrangements for deposition services; that I have acted in compliance with the prohibition on contractual relationships, as defined by Louisiana Code of Civil Procedure Article 1434 and in rules and advisory opinions of the board; that I have no actual knowledge of any prohibited employment or contractual relationship, direct or indirect, between a court reporting firm and any party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter; I am not related to counsel or to the parties herein, nor am I otherwise interested in the outcome of this matter.

____
KATHY ELLSWORTH SHAW, CCR, RPR
Certified Court Reporter
Curren Court Reporters
749 Aurora Avenue
Suite 4
Metairie, Louisiana 70005

Exhibit No. ___ (VP-9)
Advisors' Recommended Electric Revenue Requirements by Rate Class

Line No.	Description	Total Company Adjusted	RES	Large Electric	Small Electric	Large Interruptible Service	Large Electric High Load Factor	High Voltage	Municipal Building	Master Metered Non Res	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
1	Rate Base	777,383,427	424,682,735	48,893,955	114,193,326	4,878,031	165,316,569	6,019,636	3,953,658	75,118	9,370,399
2	ENO Required Rate of Return on Rate Base After taxes	6.91%									
3	ENO Required Rate of Return on Rate Base Including taxes	8.48%	1.82%	15.09%	19.00%	15.00%	15.08%	15.09%	19.00%	19.00%	19.00%
4	Return on Rate Base including income taxes	65,924,364	7,732,791	7,378,098	21,696,732	731,705	24,930,301	908,363	751,353	14,275	1,780,751
5	Operation & Maintenance Expense	404,211,278	189,397,180	29,242,020	60,918,208	6,429,029	104,889,413	7,812,601	2,110,860	42,613	3,369,352
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	4,538,904	2,432,311	293,174	685,070	21,992	994,680	38,495	23,253	451	49,478
8	Interest on Customer Deposits	895,555	493,257	55,465	133,448	3,997	186,974	6,797	4,488	86	11,042
9	Other Credit Fees	46,620	25,678	2,887	6,947	208	9,733	354	234	4	575
10	Depreciation & Amortization Expense	53,459,952	29,405,407	3,294,337	7,906,112	346,658	11,160,080	467,531	268,215	5,045	606,567
11	Amortization of Plant Acquisition Adjustment	1,189,690	540,672	91,545	185,581	15,824	319,821	24,277	6,675	133	5,161
12	Taxes Other than Income	20,940,293	11,568,176	1,270,820	3,148,925	107,084	4,308,106	180,572	105,215	1,993	249,401
13	SSCR (will be recovered w/ a Rider)	14,815,179	6,771,975	1,061,261	2,599,421	129,305	3,603,826	258,953	107,355	2,064	281,019
14	EECR (will be recovered w/ a Rider)	6,005,758	2,365,561	845,922	54,660	576,815	2,012,843	667	149,290	-	-
15	Less Credit to COS from Other Operating Revenue	(8,278,099)	(4,036,579)	(589,289)	(1,265,080)	(78,019)	(2,055,185)	(99,700)	(46,634)	(963)	(106,650)
16	Total Cost of Service	563,749,493	246,696,430	42,946,239	96,070,024	8,284,598	150,360,593	9,598,911	3,480,305	65,703	6,246,695
17	Less Present Revenue	596,853,414	250,098,239	46,736,829	96,599,501	11,061,296	166,588,860	13,381,097	3,773,720	79,482	8,534,390
18	= Revenue Deficiency (Excess)	(33,103,921)	(3,401,809)	(3,790,590)	(529,477)	(2,776,698)	(16,228,267)	(3,782,187)	(293,415)	(13,779)	(2,287,695)

Entergy New Orleans, LLC
Summary Model Results - Revenue Requirement
For the Test Year Ended December 31, 2018

Switch Status: 1 Use Global Variable manual overrides

			Total Company Adjusted		High Voltage	Large Electric High Load Factor	Large Electric	Large Interruptible Service	Lighting	Master Metered Non Res	Municipal Building	RES	Small Electric
					RO	RO	RO	RO	RO	RO	RO	RO	RO
		LINE ITEM NAME	**TOTAL COMPANY ADJUSTED**	**TOTAL RETAIL**	**HIGH VOLTAGE: HIGH VOLTAGE**	**LARGE ELECTRIC HIGH LOAD FACTOR: LARGE ELECTRIC HIGH LOAD FACTOR**	**LARGE ELECTRIC: LARGE ELECTRIC**	**LARGE INTERRUPTIBLE SERVICE: LARGE INTERRUPTIBLE SERVICE**	**LIGHTING: LIGHTING**	**MASTER METERED NON RES: MASTER METERED NON RES**	**MUNICIPAL BUILDING: MUNICIPAL BUILDING**	**RES: RESIDENTIAL**	**SMALL ELECTRIC: SMALL ELECTRIC**
	SUMMARY OF RESULTS												
1	RATE BASE	RBTOA	777,383,425	777,383,425	5,995,785	164,739,772	48,750,285	4,645,876	9,412,623	75,013	3,942,686	425,338,913	114,482,471
	REVENUES												
2	RATE SCHEDULE REVENUE	RSRTOA	596,853,414	596,853,414	10,325,289	144,697,128	42,299,402	5,155,354	11,357,996	82,253	4,278,797	274,038,016	104,619,181
3	OTHER SALES FOR RESALE	RSORTOA	-	-	-	-	-	-	-	-	-	-	-
4	TOTAL SALES REVENUES **(L2 + L3)**	RSTOA	596,853,414	596,853,414	10,325,289	144,697,128	42,299,402	5,155,354	11,357,996	82,253	4,278,797	274,038,016	104,619,181
5	OTHER OPERATING REVENUES	ROTOA	8,278,099	8,278,099	80,786	1,805,658	533,540	44,757	131,393	936	49,118	4,313,506	1,318,405
6	PROVISION FOR RATE REFUND	PROVRRTOA	-	-	-	-	-	-	-	-	-	-	-
7	TOTAL REVENUES **(L4 + L5 + L6)**	RTOA	605,131,513	605,131,513	10,406,075	146,502,785	42,832,943	5,200,111	11,489,388	83,188	4,327,915	278,351,522	105,937,586
8	TOTAL OPERATING EXPENSES	OETOA	511,572,239	511,572,239	8,916,730	126,729,432	36,126,361	6,305,561	6,038,276	58,338	2,971,993	243,586,502	80,839,046
9	TOTAL OPERATING INCOME **(L7 - L8)**	OITOA	93,559,274	93,559,274	1,489,345	19,773,353	6,706,581	(1,105,450)	5,451,113	24,850	1,355,923	34,765,020	25,098,540
10	EARNED RATE OF RETURN ON RATE BASE **(L9 / L1)**	EROR	12.04%	12.04%	24.84%	12.00%	13.76%	-23.79%	57.91%	33.13%	34.39%	8.17%	21.92%
	REVENUE REQUIREMENT DETERMINATION												
11	REQUIRED RATE OF RETURN	ROR	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%
12	REQUIRED OPERATING INCOME **(L1 * L11)**	ROI	53,678,326	53,678,326	414,009	11,375,281	3,366,207	320,798	649,942	5,180	272,242	29,369,652	7,905,015
	REVENUE CONVERSION FACTORS												
	BAD DEBT RATE	BDRATE	0.00191	0.00191	-	0.00020	0.00070	-	0.00117	-	-	0.00766	0.00144
	FORFEITED DISCOUNTS RATE	FDRATE	-	-	-	-	-	-	-	-	-	-	-
	REGULATORY COMMISSION EXPENSE RATE	RCEXP	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184	0.00184
	REVENUE-RELATED TAX RATE	FTX	-	-	-	-	-	-	-	-	-	-	-
	COMPOSITE INCOME TAX RATE	INCTAX	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080	0.26080
	FEDERAL CORPORATE INCOME TAX RATE	FCITR	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000
	EFFECTIVE STATE TAX RATE	ESTR	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430	0.06430
13	REVENUE CONVERSION FACTOR - BAD DEBT	REVCOFBD	0.19%	0.19%	-	0.02%	0.07%	-	0.12%	-	-	0.77%	0.14%
14	REVENUE CONVERSION FACTOR - FORFEITED DISCOUNTS	REVCOFFD	-	-	-	-	-	-	-	-	-	-	-
15	REVENUE CONVERSION FACTOR - REGULATORY COMMISSION EXPENSE	REVCOFRC	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
16	REVENUE CONVERSION FACTOR - REVENUE-RELATED TAX	REVCOFRT	-	-	-	-	-	-	-	-	-	-	-
17	REVENUE CONVERSION FACTOR - INCOME TAX	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
18	REVENUE CONVERSION FACTOR - FEDERAL INCOME TAX	REVCOFITF	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
19	REVENUE CONVERSION FACTOR - STATE INCOME TAX	REVCOFITS	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
20	REVENUE CONVERSION FACTOR	REVCOF	35.79%	35.79%	35.53%	35.56%	35.62%	35.53%	35.69%	35.53%	35.53%	36.58%	35.73%
	REVENUE DEFICIENCY												
21	OPERATING INCOME DEFICIENCY **(L12 - L9)**	OIDEF	(39,880,948)	(39,880,948)	(1,075,336)	(8,398,072)	(3,340,374)	1,426,248	(4,801,171)	(19,671)	(1,083,680)	(5,395,368)	(17,193,525)
22	INCREMENTAL INCOME TAX **(L21 * L17)**	ITDEF	(14,070,332)	(14,070,332)	(379,388)	(2,962,910)	(1,178,512)	503,192	(1,693,893)	(6,940)	(382,331)	(1,903,531)	(6,066,020)
	iteration 0: INCREMENTAL REVENUE-RELATED TAX DEFICIENCY	RTDEF	-	-	-	-	-	-	-	-	-	-	-
	iteration 0: INCREMENTAL BAD DEBT DEFICIENCY	BDDEF	(103,091)	(103,091)	-	(2,285)	(3,159)	-	(7,629)	-	-	(56,373)	(33,645)
	iteration 1: INCREMENTAL REVENUE-RELATED TAX DEFICIENCY	RTDEF	-	-	-	-	-	-	-	-	-	-	-
	iteration 1: INCREMENTAL BAD DEBT DEFICIENCY	BDDEF	(103,091)	(103,091)	-	(2,285)	(3,159)	-	(7,629)	-	-	(56,373)	(33,645)
23	INCREMENTAL REVENUE-RELATED TAX **(L21 + L22 + L24) * L16**	RTDEF	-	-	-	-	-	-	-	-	-	-	-
24	INCREMENTAL BAD DEBT EXPENSE **(L21 + L22 + L23) * L15**	BDDEF	(103,281)	(103,281)	-	(2,289)	(3,165)	-	(7,643)	-	-	(56,477)	(33,706)
25	INCREMENTAL FORFEITED DISCOUNTS **(L21 + L22 + L23 + L24) * L14**	FDDEF	-	-	-	-	-	-	-	-	-	-	-
26	INCREMENTAL REGULATORY COMMISSION EXPENSE	RCDEF	(99,283)	(99,283)	(2,672)	(20,871)	(8,306)	3,544	(11,944)	(49)	(2,693)	(13,510)	(42,783)
27	TOTAL REVENUE DEFICIENCY / (EXCESS) **(SUM(L21 : L26))**	REVDEF	(53,951,280)	(53,951,280)	(1,454,724)	(11,360,981)	(4,518,886)	1,929,440	(6,495,064)	(26,610)	(1,466,011)	(7,298,899)	(23,259,545)
28	% INCREASE / (DECREASE) **(L27 / L2)**	REVDEFPCT	-9.04%	-9.04%	-14.09%	-7.85%	-10.68%	37.43%	-57.18%	-32.35%	-34.26%	-2.66%	-22.23%
29	**RATE SCHEDULE REVENUE REQUIREMENT (L2 + L27)**	**REVREQ**	**542,902,134**	**542,902,134**	**8,870,565**	**133,336,146**	**37,780,516**	**7,084,794**	**4,862,931**	**55,642**	**2,812,785**	**266,739,117**	**81,359,636**

Entergy New Orleans, LLC
Summary Model Results - Revenue Requirement
For the Test Year Ended December 31, 2018

Switch Status:
1 Use Global Variable manual overrides

			Total Company Adjusted		High Voltage	Large Electric High Load Factor	Large Electric	Large Interruptible Service	Lighting	Master Metered Non Res	Municipal Building	RES	Small Electric
		LINE ITEM NAME	**TOTAL COMPANY ADJUSTED**	**TOTAL RETAIL**	**HIGH VOLTAGE: HIGH VOLTAGE**	**LARGE ELECTRIC HIGH LOAD FACTOR: LARGE ELECTRIC HIGH LOAD FACTOR**	**LARGE ELECTRIC: LARGE ELECTRIC**	**LARGE INTERRUPTIBLE SERVICE: LARGE INTERRUPTIBLE SERVICE**	**LIGHTING: LIGHTING**	**MASTER METERED NON RES: MASTER METERED NON RES**	**MUNICIPAL BUILDING: MUNICIPAL BUILDING**	**RES: RESIDENTIAL**	**SMALL ELECTRIC: SMALL ELECTRIC**
	RATE BASE SUMMARY												
1	PLANT IN SERVICE	PLTOA	1,474,833,562	1,474,833,562	12,253,529	311,455,848	91,706,339	9,671,312	15,873,048	140,480	7,377,397	808,689,312	217,666,295
2	ACCUMULATED DEPRECIATION / AMORTIZATION	ADTOA	(540,927,799)	(540,927,799)	(4,979,686)	(110,369,277)	(32,217,776)	(4,034,515)	(4,733,826)	(49,047)	(2,598,090)	(301,954,598)	(79,990,983)
3	NET PLANT	NPSUM	933,905,762	933,905,762	7,273,843	201,086,571	59,488,563	5,636,797	11,139,221	91,433	4,779,307	506,734,714	137,675,312
4	WORKING CASH	WCTOA	(1,481,220)	(1,481,220)	(11,424)	(313,894)	(92,888)	(8,852)	(17,935)	(143)	(7,512)	(810,437)	(218,134)
5	FUEL INVENTORY	FITOA	-	-	-	-	-	-	-	-	-	-	-
6	MATERIALS AND SUPPLIES EXCLUDING ALLOWANCES	MSXATOA	9,852,410	9,852,410	110,044	2,282,001	666,817	79,901	92,172	1,008	51,835	5,082,435	1,486,196
7	PREPAYMENTS	PPTOA	7,289,782	7,289,782	60,720	1,534,547	451,888	47,713	79,447	693	36,475	4,001,342	1,076,956
8	PROPERTY INSURANCE RESERVE	PIRTOA	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
9	INJURIES & DAMAGES RESERVES	IDRTOA	(4,564,274)	(4,564,274)	(31,305)	(634,919)	(190,328)	(22,062)	(87,400)	(306)	(19,319)	(2,897,277)	(681,358)
10	COAL CAR MAINTENANCE RESERVE	CCMRTOA	-	-	-	-	-	-	-	-	-	-	-
11	UNFUNDED PENSION	PENTOA	33,140,318	33,140,318	227,302	4,610,021	1,381,935	160,185	634,597	2,223	140,273	21,036,570	4,947,212
12	ALLOWANCES	AINTOA	5,535	5,535	147	1,764	461	153	55	1	29	2,114	811
13	COMMERCIAL LITIGATION	APCLTOA	-	-	-	-	-	-	-	-	-	-	-
14	ENVIRONMENTAL RESERVES	ERTOA	-	-	-	-	-	-	-	-	-	-	-
15	CUSTOMER DEPOSITS	CDTOA	(22,632,164)	(22,632,164)	(174,557)	(4,796,111)	(1,419,280)	(135,257)	(274,032)	(2,184)	(114,784)	(12,383,001)	(3,332,958)
16	ACCUMULATED DEFERRED INCOME TAXES	ADITTOA	(194,063,261)	(194,063,261)	(1,496,767)	(41,125,057)	(12,169,850)	(1,159,780)	(2,349,734)	(18,726)	(984,238)	(106,180,109)	(28,579,001)
17	ACCUMULATED DEFERRED ITC	ADITCTOA	-	-	-	-	-	-	-	-	-	-	-
18	RATE CASE EXPENSES	RCETOA	-	-	-	-	-	-	-	-	-	-	-
19	REGULATORY ASSETS AND LIABILITIES	REGASSLIABTOA	17,510,576	17,510,576	108,039	2,690,044	797,189	90,030	179,814	1,238	71,102	11,193,084	2,380,036
20	AMORTIZATION ACQUISITION ADJUSTMENT	AAATOA	(4,574,846)	(4,574,846)	(93,354)	(1,229,842)	(352,030)	(60,850)	(19,846)	(512)	(25,669)	(2,079,108)	(713,635)
21	OTHER RATE BASE	OTHRBTOA	2,994,808	2,994,808	23,098	634,647	187,807	17,898	36,261	289	15,189	1,638,584	441,035
22	**RATE BASE**	**RBTOA**	**777,383,425**	**777,383,425**	**5,995,785**	**164,739,772**	**48,750,285**	**4,645,876**	**9,412,623**	**75,013**	**3,942,686**	**425,338,913**	**114,482,471**

Entergy New Orleans, LLC
Summary Model Results - Revenue Requirement
For the Test Year Ended December 31, 2018

Switch Status:
1 Use Global Variable manual overrides

			Total Company Adjusted		High Voltage	Large Electric High Load Factor	Large Electric	Large Interruptible Service	Lighting	Master Metered Non Res	Municipal Building	RES	Small Electric
		LINE ITEM NAME	**TOTAL COMPANY ADJUSTED**	**TOTAL RETAIL**	**HIGH VOLTAGE: HIGH VOLTAGE**	**LARGE ELECTRIC HIGH LOAD FACTOR: LARGE ELECTRIC**	**LARGE ELECTRIC: LARGE ELECTRIC**	**LARGE INTERRUPTIBL E SERVICE: LARGE INTERRUPTIBL E SERVICE**	**LIGHTING: LIGHTING**	**MASTER METERED NON RES: MASTER METERED NON RES**	**MUNICIPAL BUILDING: MUNICIPAL BUILDING**	**RES: RESIDENTIAL**	**SMALL ELECTRIC: SMALL ELECTRIC**
	REVENUES												
1	SALES REVENUES	RSTOA	596,853,414	596,853,414	10,325,289	144,697,128	42,299,402	5,155,354	11,357,996	82,253	4,278,797	274,038,016	104,619,181
2	OTHER OPERATING REVENUES	ROTOA	8,278,099	8,278,099	80,786	1,805,658	533,540	44,757	131,393	936	49,118	4,313,506	1,318,405
3	PROVISION FOR RATE REFUND	PROVRRTOA	-	-	-	-	-	-	-	-	-	-	-
4	**TOTAL REVENUES**	**RTOA**	**605,131,513**	**605,131,513**	**10,406,075**	**146,502,785**	**42,832,943**	**5,200,111**	**11,489,388**	**83,188**	**4,327,915**	**278,351,522**	**105,937,586**
	OPERATING EXPENSES												
	O&M EXPENSE												
5	PRODUCTION EXPENSES	OMPTOA	323,026,723	323,026,723	7,216,294	91,899,761	25,508,841	5,755,066	1,973,659	36,826	1,775,834	139,437,984	49,422,459
6	TRANSMISSION EXPENSES	OMTTOA	9,130,299	9,130,299	184,819	2,434,763	696,925	193,789	39,291	1,017	50,818	4,116,067	1,412,808
7	REGIONAL MARKET EXPENSES	OMRTOTOA	0	0	0	0	0	0	0	0	0	0	0
8	DISTRIBUTION EXPENSES	OMDTOA	20,666,643	20,666,643	26,063	3,832,063	1,137,318	15,014	465,987	1,786	104,183	12,068,283	3,015,946
9	CUSTOMER ACCOUNTING EXPENSES	OMCATOA	9,231,194	9,231,194	258	59,601	47,262	12,781	27,996	37	10,191	8,217,425	855,644
10	CUSTOMER SERVICES EXPENSES	OMCSTOA	1,005,563	1,005,563	31	3,007	1,653	1,814	2,779	4	1,318	900,085	94,872
11	SALES EXPENSES	OMSTOA	364,360	364,360	3,111	80,530	23,698	2,416	3,930	36	1,881	194,331	54,428
12	ADMINISTRATIVE & GENERAL EXPENSES	OMAGTOA	40,786,503	40,786,503	284,482	5,804,589	1,737,222	202,658	766,813	2,786	174,000	25,727,084	6,086,870
13	OPERATION & MAINTENANCE EXPENSE	OMTOA	404,211,285	404,211,285	7,715,058	104,114,314	29,152,919	6,183,538	3,280,454	42,493	2,118,224	190,661,260	60,943,027
14	GAINS FROM DISP OF ALLOWANCES	GFDATOA	-	-	-	-	-	-	-	-	-	-	-
15	REGULATORY DEBITS AND CREDITS	RDCTOA	4,538,904	4,538,904	38,751	1,003,174	295,209	30,096	48,952	452	23,427	2,420,822	678,021
16	INTEREST ON CUSTOMER DEPOSITS	ICDTOA	895,555	895,555	6,907	189,782	56,161	5,352	10,843	86	4,542	489,996	131,885
17	OTHER CREDIT FEES	OCFTOA	46,620	46,620	360	9,880	2,924	279	564	4	236	25,508	6,866
18	DEPRECIATION AND AMORTIZATION EXPENSE	DXTOA	59,962,153	59,962,153	467,754	11,167,569	3,296,141	353,263	606,114	5,046	268,365	29,395,752	7,899,949
19	AMORTIZATION OF PLANT ACQUISITION ADJUSTMENT	APAATOA	1,189,690	1,189,690	24,277	319,821	91,545	15,824	5,161	133	6,675	540,672	185,581
20	ACCRETION EXPENSE	ACCRETTOA	-	-	-	-	-	-	-	-	-	-	-
21	TAXES OTHER THAN INCOME	TOTOA	20,940,293	20,940,293	181,630	4,343,957	1,279,645	136,916	247,602	1,997	105,934	11,518,901	3,123,711
	CURRENT INCOME TAXES												
	TOTAL REVENUES	RTOA	605,131,513	605,131,513	10,406,075	146,502,785	42,832,943	5,200,111	11,489,388	83,188	4,327,915	278,351,522	105,937,586
	OPERATION & MAINTENANCE EXPENSE	OMTOA	404,211,285	404,211,285	7,715,058	104,114,314	29,152,919	6,183,538	3,280,454	42,493	2,118,224	190,661,260	60,943,027
	GAINS FROM DISP OF ALLOWANCES	GFDATOA	-	-	-	-	-	-	-	-	-	-	-
	REGULATORY DEBITS AND CREDITS	RDCTOA	4,538,904	4,538,904	38,751	1,003,174	295,209	30,096	48,952	452	23,427	2,420,822	678,021
	INTEREST ON CUSTOMER DEPOSITS	ICDTOA	895,555	895,555	6,907	189,782	56,161	5,352	10,843	86	4,542	489,996	131,885
	OTHER CREDIT FEES	OCFTOA	46,620	46,620	360	9,880	2,924	279	564	4	236	25,508	6,866
	DEPRECIATION AND AMORTIZATION EXPENSE	DXTOA	59,962,153	59,962,153	467,754	11,167,569	3,296,141	353,263	606,114	5,046	268,365	29,395,752	7,899,949
	AMORTIZATION OF PLANT ACQUISITION ADJUSTME	APAATOA	1,189,690	1,189,690	24,277	319,821	91,545	15,824	5,161	133	6,675	540,672	185,581
	AMORTIZATION OF PROPERTY	APLTOA	-	-	-	-	-	-	-	-	-	-	-
	ACCRETION EXPENSE	ACCRETTOA	-	-	-	-	-	-	-	-	-	-	-
	DECOMMISSIONING EXPENSE	DECOMMTOA	-	-	-	-	-	-	-	-	-	-	-
	TAXES OTHER THAN INCOME	TOTOA	20,940,293	20,940,293	181,630	4,343,957	1,279,645	136,916	247,602	1,997	105,934	11,518,901	3,123,711
	GAIN/LOSS ON DISPOSITION OF UTILITY PLANT	GLDUPTOA	-	-	-	-	-	-	-	-	-	-	-
	Total Operating Expenses (before taxes)	**OETOA**	**491,784,500**	**491,784,500**	**8,434,736**	**121,148,497**	**34,174,544**	**6,725,267**	**4,199,690**	**50,212**	**2,527,404**	**235,052,910**	**72,969,039**
	NET INCOME BEFORE INCOME TAXES	**NIBTACALC**	**113,347,014**	**113,347,014**	**1,971,338**	**25,354,288**	**8,658,399**	**(1,525,156)**	**7,289,699**	**32,976**	**1,800,512**	**43,298,612**	**32,968,547**
	ADJUSTMENTS TO NET INCOME	CTTOA	(18,924,051)	(18,924,051)	(139,007)	(3,224,223)	(962,129)	(97,381)	(325,406)	(1,516)	(87,797)	(11,262,067)	(2,824,527)
	FEDERAL TAXABLE INCOME	**CTTITO**	**94,422,962**	**94,422,962**	**1,832,332**	**22,130,066**	**7,696,270**	**(1,622,537)**	**6,964,293**	**31,461**	**1,712,715**	**32,036,545**	**30,144,020**
	STATE ADJUSTMENTS TO NET INCOME	STATOA	(159,978)	(159,978)	(1,366)	(33,891)	(9,972)	(1,079)	(1,701)	(15)	(801)	(87,531)	(23,622)
	STATE TAXABLE INCOME	**STATITO**	**94,262,985**	**94,262,985**	**1,830,966**	**22,096,175**	**7,686,298**	**(1,623,615)**	**6,962,592**	**31,446**	**1,711,914**	**31,949,014**	**30,120,398**
	State Income Tax Rate	ESTR	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	STATE INCOME TAX	STCALC	6,061,110	6,061,110	117,731	1,420,784	494,229	(104,398)	447,695	2,022	110,076	2,054,322	1,936,742
	ADJUSTMENTS TO STATE INCOME TAX	STATO	131,174	131,174	900	18,247	5,470	634	2,512	9	555	83,266	19,582
	Total State Taxes	**STTOA**	**6,192,284**	**6,192,284**	**118,631**	**1,439,031**	**499,699**	**(103,764)**	**450,206**	**2,031**	**110,631**	**2,137,587**	**1,956,323**
	FEDERAL ADJUSTMENTS TO NET INCOME	FTATOA	(6,479,201)	(6,479,201)	(117,731.09)	(1,420,784.06)	(494,228.94)	104,398.46	(447,694.66)	(2,021.96)	(110,076.05)	(2,054,321.62)	(1,936,741.58)
	Federal Tax Taxable Income	**FEDTITO**	**87,943,761**	**87,943,761**	**1,714,601**	**20,709,282**	**7,202,041**	**(1,518,138)**	**6,516,598**	**29,439**	**1,602,638**	**29,982,224**	**28,207,279**
	Federal Income Tax Rate	FCITR	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
	FEDERAL INCOME TAX	FTCALC	18,468,190	18,468,190	360,066	4,348,949	1,512,429	(318,809)	1,368,486	6,182	336,554	6,296,267	5,923,528
	ADJUSTMENTS TO FEDERAL INCOME TAX	FTATO	359,056	359,056	2,463	49,947	14,972	1,736	6,875	24	1,520	227,919	53,600
	FEDERAL INCOME TAX	**FTTOA**	**18,827,246**	**18,827,246**	**362,529**	**4,398,896**	**1,527,401**	**(317,074)**	**1,375,361**	**6,206**	**338,074**	**6,524,186**	**5,977,129**
22	FEDERAL INCOME TAX	FTTOA	18,827,246	18,827,246	362,529	4,398,896	1,527,401	(317,074)	1,375,361	6,206	338,074	6,524,186	5,977,129
23	STATE INCOME STATE	STTOA	6,192,284	6,192,284	118,631	1,439,031	499,699	(103,764)	450,206	2,031	110,631	2,137,587	1,956,323
	CURRENT INCOME TAXES	CITTOA	25,019,530	25,019,530	481,160	5,837,927	2,027,100	(420,838)	1,825,568	8,237	448,705	8,661,773	7,933,452
	PROVISION FOR DEFERRED INCOME TAXES												
24	PROVISION FOR DEFERRED INCOME TAXES - FEDERAL	DTFTOA	(692,577)	(692,577)	(1,934)	(259,265)	(76,034)	(1,185)	6,688	(113)	(4,640)	(263,252)	(92,842)
25	PROVISION FOR DEFERRED INCOME TAXES - STATE	DTSTOA	268,794	268,794	3,523	21,744	6,484	2,903	7,323	11	982	183,079	42,744
26	PROVISION FOR DEFERRED INCOME TAXES	DTTOA	(423,784)	(423,784)	1,589	(237,521)	(69,550)	1,718	14,011	(102)	(3,658)	(80,173)	(50,098)
27	INVESTMENT TAX CREDITS A/C 411	ITCTOA	(89,358)	(89,358)	(755)	(19,471)	(5,733)	(585)	(992)	(9)	(458)	(48,008)	(13,347)
28	**TOTAL OPERATING EXPENSES**	**OETOA**	**516,378,687**	**516,290,887**	**8,916,730**	**126,729,432**	**36,126,361**	**6,305,561**	**6,038,276**	**58,338**	**2,971,993**	**243,586,502**	**80,839,046**

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC FOR A	**)**	
CHANGE IN ELECTRIC AND GAS	**)**	**DOCKET NO. UD-18-07**
RATES PURSUANT TO	**)**	
COUNCIL RESOLUTIONS R-15-194 AND	**)**	
R-17-504 AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

D. ANDREW OWENS

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Introduction

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. Andrew Owens. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ARE YOU THE SAME D. ANDREW OWENS WHO FILED REVISED DIRECT TESTIMONY IN THIS DOCKET IN SEPTEMBER 2018?

A. Yes.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

B. Purpose of Testimony

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain questions and concerns raised by several witnesses for the Council's Advisors ("Advisors") and the Alliance for Affordable Energy ("Alliance") with respect to the Company's proposals regarding implementation of decoupling, Energy Smart cost recovery, community solar, and investments in electric vehicle ("EV") charging infrastructure. I also briefly discuss Building Science Innovators, LLC's ("BSI") proposed Customer Lowered Electricity Price ("CLEP").

II. DECOUPLING

Q5. WHAT ISSUES HAVE BEEN RAISED WITH RESPECT TO THE DECOUPLING PROPOSAL WITHIN ENO'S PROPOSED FORMULA RATE PLAN ("FRP")?

A. Alliance witness Pamela G. Morgan recommends a number of changes to ENO's proposed decoupling mechanism, citing as justification that ENO's proposed decoupling mechanism does not appear to comply with the decoupling mechanism ordered in Council Resolution R-16-103 (the "Decoupling Resolution") or how decoupling is commonly understood.[1] Advisors' witness Victor Prep asserts that portions of ENO's proposal do not conform to the Decoupling Resolution, while at the same time recommending certain features himself that are not contemplated by the Decoupling Resolution. I address some of these issues, and Company witness Matthew S. Klucher addresses Mr. Prep's recommendations concerning cost of service, the FRP, and other issues relating to decoupling in that context.

Q6. PLEASE DESCRIBE WHY THE COMPANY INCLUDED A DECOUPLING PROPOSAL WITHIN ITS PROPOSED FRP.

A. In conjunction with its 2012 Integrated Resource Plan ("IRP") proceeding (Docket No. UD-08-02), the Council issued Resolution No. R-13-363 dated October 10, 2013, which directed ENO to file a decoupling proposal for consideration by the Council. It is important to note that Resolution No. R-13-363 did not prescribe the parameters and/or features of decoupling. Instead, that Resolution served to initiate a more than

1 *See* Direct Testimony of Pamela G. Morgan at 3.

two-year collaborative process that involved stakeholder engagement (including participation by the Alliance), several full-day technical meetings, and multiple rounds of written comments before the Advisors issued their final Report and Recommendations to the Council on February 10, 2016 ("Advisor Report"). After further opportunity for public comment, the Council adopted the Advisor Report and issued the Decoupling Resolution April 7, 2016. The Decoupling Resolution set forth a number of specific requirements to incorporate a decoupling proposal into ENO's next base rate case, which occurred when ENO refiled its 2018 Combined Rate Case in September 2018.

Q7. WAS ISSUANCE OF THE DECOUPLING RESOLUTION THE LAST STEP IN THE DECOUPLING PROCEEDING?

A. No, it was not. Paragraph 13 of the Decoupling Resolution required the Company to collaborate with the Council's Advisors to develop various illustrative examples of how the decoupling mechanism described in the Decoupling Resolution would operate in two different scenarios: (1) assuming the Council approves a decoupling mechanism and an FRP in conjunction with ENO's next base rate case, and (2) assuming the Council approves a decoupling mechanism without an FRP. On September 6, 2016, the Company submitted a report to the Council, Advisors, and other parties (including the Alliance) summarizing 11 different illustrative examples (eight within an FRP and three absent an FRP).

Q8. DO YOU BELIEVE THAT THE COMPANY'S FRP/DECOUPLING PROPOSAL COMPLIES WITH THE DECOUPLING RESOLUTION?

A. Yes. The Company's overall decoupling proposal, within the context of a proposed FRP, follows the requirements contained in Paragraphs 1 through 12 in the Decoupling Resolution. Mr. Klucher addresses certain issues on which ENO and the Advisors appear to disagree on the mechanism for implementing any resulting rate adjustment.

Q9. HOW DO YOU RESPOND TO MS. MORGAN'S CONCERN THAT THE COMPANY'S PROPOSAL IS NOT CONSISTENT WITH DECOUPLING AS IT "IS COMMONLY UNDERSTOOD?"[2]

A. Ms. Morgan's observations and recommendations filed almost three years after issuance of the Decoupling Resolution are essentially advocating for the Council to revisit its conclusions in Docket No. UD-08-02 and the Decoupling Resolution. Accordingly, Ms. Morgan's recommendations have no bearing on the merits of whether ENO's proposal complies with the Decoupling Resolution.

Ms. Morgan confirmed at her deposition that she had no involvement in the lengthy decoupling proceeding that occurred from late 2013 up until ENO's submittal of multiple illustrative examples in September 2016 and that she had not reviewed the associated comments and reports filed in Docket No. U-08-02 during that time

[2] Morgan Direct at 3.

period.[3] Thus, Ms. Morgan is understandably unfamiliar with the background that led to the Council issuing the Decoupling Resolution embodying the parameters for the specific decoupling mechanism that the Company was required to implement in its 2018 Combined Rate Case. Ms. Morgan's recommendations would alter the decoupling structure embodied in the Decoupling Resolution, as she explains in her testimony,[4] and are not relevant to a determination of whether ENO's proposal complies with the specific decoupling structure established in the Council's Decoupling Resolution.

Q10. WHAT IS YOUR ASSESSMENT OF MS. MORGAN'S RECOMMENDATIONS WITH RESPECT TO CONFORMING ENO'S PROPOSAL TO "STANDARD DECOUPLING?"

A. Should the Council wish to reevaluate the methodology regarding the steps necessary to implement a pilot decoupling framework within an FRP in this rate case, ENO would be supportive – provided the overall outcome preserves the essential features of the FRP and addresses important issues like timely recovery of lost contributions to fixed costs ("LCFC"). In conjunction with Ms. Morgan's deposition, the Company prepared a side-by-side example that compared a summary of the illustrative example in Phillip Gillam's Exhibit PBG-8 included in his Revised Direct Testimony with the

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[3] *See* Deposition of Pamela G. Morgan at 25-28 (March 14, 2019) (excerpts are provided in my workpapers).

[4] Morgan Direct at 8-10.

Company's understanding of the steps contemplated by Ms. Morgan in her Direct Testimony (attached as Exhibit DAO-6).

On the left side of Exhibit DAO-6 (the overall outcome of the Exhibit PBG-8 illustrative example, which is based on a number of assumptions), is a residential class rate change of $3,055,611, resulting in an FRP rate change of approximately 1.6082%. On the right side of Exhibit DAO-6, the first series of steps (1 through 3) accomplishes revenue decoupling as confirmed by Ms. Morgan during her deposition[5] and results in a rate change of $1,704,433 — equal to a percentage change of approximately 0.8971%. The $1,704,433 value was also calculated by Ms. Morgan and appears in her Direct Testimony.[6]

Ms. Morgan went on to explain in her deposition that she was not taking a position one way or another on FRP steps 5 through 6, and that as long as decoupling was accomplished via steps 1 through 3 and a resulting rate change was put in place every year, revenue decoupling was being accomplished regardless of whether the FRP component has a dead band or results in a rate change.[7] In other words, my understanding of the Alliance's decoupling proposal is that decoupling is complete with steps 1 through 3 in Exhibit DAO-6, and that as long as those steps occur for each rate class, every year, Ms. Morgan neither supports nor is opposed to other features of the Company's proposed FRP. With that understanding, the Company would be supportive of altering its FRP proposal to memorialize the steps necessary

5 *See* Morgan Deposition at 34-37.

6 Morgan Direct at 17.

7 *See* Morgan Deposition at 37-40.

to implement a different decoupling mechanism provided that the Council is open to revising the mechanism prescribed in the Decoupling Resolution.

Q11. WOULD MS. MORGAN'S DECOUPLING PROPOSAL WORK SIMULTANEOUSLY WITH ENO'S PROPOSED FRP/DECOUPLING MECHANISM?

A. No. The Alliance's recommendation would be an entirely different alternative mechanism that would replace the portion of the FRP proposal addressing decoupling in its entirety. Further, if implemented, the concept would seem to make the decoupling/FRP allocation issues discussed by Mr. Klucher moot. That is because, as I understand the concept advocated by Ms. Morgan, the decoupling shown in steps 1 through 3 in Exhibit DAO-6 would address the "allocation" issues, and the second set of FRP-related steps shown in that Exhibit would occur more along the lines of how FRP adjustments have traditionally been calculated and implemented, subject to whatever specific provisions might exist for a dead band or other FRP mechanics.

III. LOST CONTRIBUTIONS TO FIXED COSTS

Q12. PLEASE BRIEFLY SUMMARIZE THE PROPOSAL FOR TREATMENT OF LCFC SET FORTH IN THE COMPANY'S APPLICATION.

A. As part of its proposed Demand-Side Management Cost Recovery Rider ("Rider DSMCR"), ENO would calculate a projected annualized LCFC amount based upon anticipated DSM investments to be made in the next test year. The methodology would follow the practice that has been in place since the inception of Energy Smart where a single, weighted-average value is used, which represents fixed cost recovery that does not occur because of annualized lost volumetric (kWh) sales resulting from the Company's DSM investments. If Rider DSMCR were to be approved, the initial projected annualized LCFC amount would be reflected only in 2020. Assuming that an FRP is approved, for 2021 and beyond for as long as an FRP stays in place, only the incremental (or decremental) level of LCFC relative to the prior year would be incorporated into Rider DSMCR.

Q13. DO THE WITNESSES THAT ADDRESSED THE COMPANY'S LCFC PROPOSAL SEEM TO FULLY UNDERSTAND THE PROPOSAL?

A. Not entirely. Ms. Morgan's Direct Testimony expresses some confusion about the timing of LCFC collection under the Company's proposal and the interplay between the LCFC proposal and the proposed FRP.[8] Further elaboration using the illustrative example included beginning on page 29 of my Revised Direct Testimony may help clarify several aspects that Ms. Morgan addressed in her Direct Testimony. My illustrative example of Rider DSMCR for 2020 includes a projected annualized LCFC amount of $2.5 million. As described above, the $2.5 million amount would have been calculated using annualized lost kWh sales based on forecasted DSM investments implemented in 2020 multiplied by a single Council-reviewed and agreed-upon weighted-average value (expressed in $ per kWh) representing lost contributions to cover fixed costs.

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8 *See* Morgan Direct at 30.

Beginning with the January 2020 billing cycle, Rider DSMCR would reflect the $2.5 million value in addition to its other components. Because there would not yet be a full year of history, ENO's October 2020 filing to the Council would reflect the Company's investment plans for 2021, but not any true-ups for actuals. Assume for illustrative purposes that the projected annualized LCFC amount for DSM investments to be made in 2021 is calculated at $2.7 million. Beginning with the January 2021 billing cycle, Rider DSMCR would be updated to reflect the incremental $200,000 of calculated LCFC. Put another way, the $2.5 million reflected in 2020 is being removed and replaced by $2.7 million for 2021. In subsequent years, the same approach would be followed with only the incremental (or decremental) LCFC relative to the prior year being reflected in Rider DSCMR (again, assuming that an FRP is approved).

The reason for addressing LCFC in this manner is that the proposed FRP will eventually "catch up" and address the 2020 test year's LCFC (even if the 2020TY FRP does not result in a rate change, which I address further below). There will be a lag period at the start that covers January 2021 until FRP rates are first reset (if a rate change occurs) with the September 2021 billing cycle where LCFC is left unaddressed. That was a deliberate policy decision made by the Company in the design of Rider DSMCR to simplify the true-up process given the different effective dates for rate changes under Rider DSCMR (January billing cycle) relative to the FRP (September billing cycle).

Q14. ADVISOR WITNESS VICTOR PREP RECOMMENDS ON PAGE 76 OF HIS DIRECT TESTIMONY THAT LCFC NOT BE INCLUDED IN ANY COST RECOVERY MECHANISM, WHICH WOULD INCLUDE RIDER DSMCR. WHAT IS YOUR REACTION?

A. My first reaction is that the Company receiving fair treatment on the LCFC issue depends to a significant extent on the final design of the FRP. There is historic precedent for ENO having an opportunity to recover LCFC for Energy Smart investments as well as sound policy reasons. Company witness Dr. Faruqui addressed at length the rationale for allowing recovery of LCFC in his Revised Direct Testimony and addresses the issue again in his Rebuttal Testimony. My proposal to reflect LCFC in Rider DSMCR was predicated upon the Company's initial proposal for its FRP. As I described above, the two are clearly linked albeit subject to a time lag because of the different effective dates for rate changes. Assuming that the final design of the FRP incorporates features that ENO believes adequately address LCFC, which Company witness Mr. Josh Thomas discusses in his Rebuttal Testimony, then I would agree with Mr. Prep that the Company would not need to recover LCFC amounts in Rider DSMCR or through some other cost recovery mechanism (other than via the FRP, of course).

Absent adoption of the changes that Mr. Thomas discusses, I do not agree with Mr. Prep that the decoupling/FRP mechanism as proposed adequately addresses the LCFC issue.[9] Absent the LCFC component being included within Rider DSMCR

[9] Prep Direct at 76.

or another recovery mechanism, rate adjustments under the current FRP/decoupling framework would only address the recovery of lost contributions to fixed costs attributable to utility-sponsored DSM a year or more after the sales reductions actually begin to occur. Without the changes Mr. Thomas describes to address LCFC, relying only upon the proposed decoupling/FRP mechanism would create built-in lag in the recovery of the Company's fixed costs that would theoretically continue in perpetuity. In other words, the Company would always be a year or more behind in the recovery of fixed costs attributable to Energy Smart-related DSM investments, which all else equal, would deny the Company a reasonable opportunity to earn its allowed return on the energy efficiency, demand response, and other investments it makes to serve New Orleans customers. The Company's DSCMR proposal with the LCFC component, on the other hand, implements a mechanism that recovers the expected lost revenues on a prospective basis, significantly mitigating the lag in recovery of fixed costs caused by ENO implementing increased Energy Smart investments and, all else equal, providing ENO a reasonable opportunity to earn its allowed return on its investments in Energy Smart. Rider DSMCR is a better mechanism for keeping ENO in a neutral position with respect to implementing the Council's DSM goals and encouraging robust DSM initiatives in New Orleans.

Q15. ON PAGE 22 OF HER DIRECT TESTIMONY, ALLIANCE WITNESS PAMELA G. MORGAN RECOMMENDS THAT THE COUNCIL NOT INCLUDE THE LCFC COMPONENT WITHIN RIDER DSMCR. WHAT IS YOUR REACTION?

A. Ms. Morgan's recommendation appears to be based on her recommendation to adopt "standard" decoupling in lieu of the Company's proposal made pursuant to the Decoupling Resolution. Assuming that the Council does not wish to revisit its finding and conclusions in the Decoupling Resolution, I explained earlier that the LCFC component of Rider DSMCR would remain necessary given the "decoupling" structure contemplated in the Decoupling Resolution does not adequately address the LCFC issue.

In addition, even under the potential alternative decoupling structure recommend by Ms. Morgan, the lag in recovery of fixed costs due to reduced sales attributable to utility-sponsored DSM remains because adjustments are made prospectively, which means that the Company would always be a year or more behind in recovering a portion of its fixed costs attributed to reduced sales from utility-sponsored DSM. Thus, even under Ms. Morgan's decoupling proposal, I recommend maintaining the LCFC component of Rider DSMCR, unless LCFC is otherwise adequately addressed in the final design of an FRP, to keep both DSM investments and supply-side resources on a level playing field.

IV. RIDER DSMCR

Q16. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S PROPOSAL FOR RIDER DSMCR.

A. As explained in my Revised Direct Testimony, ENO is proposing to implement a new cost recovery model for Energy Smart investments beginning January 2020 to be called Rider DSMCR. If approved, this new rider would be based on utilizing regulatory asset-based accounting. As discussed above, Rider DSMCR would also provide the most effective mechanism to recover LCFC associated with DSM investments. The Company's proposal also includes a performance incentive methodology that rewards actual performance and drives cost-effective outcomes for customers.

Q17. WHY DOES THE COMPANY BELIEVE RIDER DSMCR AS PROPOSED IS THE BEST APPROACH FOR ENERGY SMART?

A. As outlined in my Revised Direct Testimony, Rider DSMCR provides a number of benefits to customers and will help balance the interests of the Company. At its core, Rider DSMCR as proposed would provide ENO an opportunity to timely recover its DSM investments while earning a return, which, as discussed at length in my Revised Direct Testimony and that of Company witness Dr. Faruqui, will help put demand-side and traditional supply-side resources on a more level playing field.

The Council, the Company, the Advisors, and many other stakeholders have been on a journey over the past decade to ramp up cost-effective DSM investments and expand opportunities for customers to take advantage of energy efficiency. In furtherance of those collective efforts, the Council has issued several resolutions requiring ENO to incorporate evaluation of the Council's long-term goal of increasing the annual energy (kWh) reductions resulting from Energy Smart equal to 0.2% of ENO's annual energy sales until such time as the annual kWh reduction reaches 2.0% of annual sales ("2% Goal") into ENO's IRP efforts and proposed Energy Smart budgets. Assuming that the 2018 IRP identifies DSM measures necessary to the 2% Goal as part of a least-cost resource portfolio and, as a result, the Council adopts targets consistent with the 2% Goal for Program Years 10 through 12 of Energy Smart, then achieving the aggressive 2% Goal will necessarily require that the Company make substantial investments in DSM, expand the offerings available from where things stand today, and add new resources.

Mr. Prep acknowledges on page 68 of his Direct Testimony that future spending on Energy Smart necessary to achieve the Council's 2% Goal will be "substantial," and I agree. Mr. Prep goes a step further and extrapolates that potential spending on Energy Smart in 2020 will be in the range of $17.5 million,[10] and which, if accurate, would represent an increase of approximately 18% over the level of total investments approved for 2019 (Planning Year 9 or "PY9"). The Company's on-going 2018 IRP proceeding validates this point in that it includes various estimates performed by third parties of the potential level of investment needed to reach what is clearly a very aggressive long-term goal. The Company strongly believes that the regulatory asset-based cost recovery model embodied within Rider DSMCR is the

[10] *See* Prep Direct at 70.

right framework to provide the regulatory and financial support necessary to achieve the Council's long-term energy usage reduction aspirations.

Q18. HAVE OTHER PARTIES EXPRESSED OPINIONS ON THE COMPANY'S PROPOSED DSMCR?

A. Yes. Advisor witness Mr. Prep and Alliance witness Mr. Barnes both express reservations about Rider DSMCR for varying reasons.

Q19. WHAT DOES MR. PREP RECOMMEND CONCERNING RIDER DSMCR?

A. Mr. Prep rejects almost out of hand the Company's Rider DSMCR and instead recommends the Council use the Interim Energy Efficiency Cost Recovery ("EECR") framework as the successor cost recovery mechanism for Energy Smart beginning in January 2020. In other words, Mr. Prep is proposing that, to the extent it becomes necessary, Interim EECR would be used for Energy Smart cost recovery during the latter half of 2019 and a permanent EECR based on the same methodology, allocation methods, etc. would be implemented beginning January 2020. My understanding of Mr. Prep's proposal is first, the permanent EECR would not include LCFC because that issue will have been addressed in the FRP, which as I discussed earlier, currently does not adequately address the LCFC issue (although it may be possible provided certain modifications to Mr. Prep's FRP recommendations are made). Second, while Mr. Prep explained at his deposition that he supports an incentive, he recommends that the mechanism and associated incentive amounts be deferred until after this proceeding when the Council considers costs and budgets for Energy Smart program years 10-12.[11] Third, Mr. Prep recommends that EECR costs should be included in the annual FRP evaluation, which means, if he is suggesting that a permanent EECR would not include an annual true-up of EECR costs and revenues, that some level of EECR costs could be under- or over-recovered.[12]

Q20. DOES MR. PREP PRESENT ANY JUSTIFICATION FOR HIS RECOMMENDATIONS RELATED TO THE USE OF EECR ON A PERMANENT BASIS?

A. The only specific criticism of Rider DSMCR that I encountered in Mr. Prep's testimony is on page 69 where he states: "Energy Smart funding requirements will likely keep increasing substantially each year, and the combined ratepayer obligations prospectively will be less with the contemporaneous Energy Smart recovery being treated as expenses, rather than as a regulatory asset."[13] Mr. Prep goes on to make the general policy assertion that "regulatory asset treatment is more appropriate if a large, non-recurring cost is recovered over several future years,"[14] which, as Dr. Faruqui discusses in more detail, does not necessarily reflect current, supportive ratemaking related to achieving meaningful DSM savings (*i.e.*, benefits to customers).

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[11] *See* Deposition of Victor Prep at 87-95 (March 14, 2019) (excerpts are provided in my workpapers).

[12] *See* Prep Direct at 68; Prep Deposition at 98-102.

[13] Prep Direct Testimony at 69.

[14] *Id*.

Q21. DO YOU AGREE WITH MR. PREP'S JUSTIFICATION FOR RECOMMENDING THAT EECR BE USED AS A PERMANENT SOURCE OF FUNDING FOR ENERGY SMART RATHER THAN RIDER DSMCR?

A. I do not. As noted above and as I more fully described in my Revised Direct Testimony, and as Dr. Faruqui also discusses, Rider DSMCR as proposed by the Company would provide financial support for, and a regulatory framework conducive to, achieving the Council's goals related to DSM savings. Mr. Prep and I both agree that DSM investments will need to increase in the coming years to achieve these goals. But I do not agree with his assertion that regulatory asset-based cost recovery will inherently mean the costs to customers would be higher.

Q22. PLEASE EXPLAIN WHY DSMCR WILL NOT RESULT IN HIGHER COSTS TO CUSTOMERS THAN RECOVERY THROUGH EECR AS MR. PREP RECOMMENDS.

A. If Rider DSMCR is implemented, the Company would amortize the regulatory asset balance over three years, which would actually occur over four calendar years under a half-year convention. In the initial years, as I showed in my illustrative example on page 30 of my Revised Direct Testimony, the recovery from customers under Rider DSMCR is **much less** than would otherwise occur with contemporaneous recovery of 100% of the investment. Over time, it is accurate to say that the overall level of recovery will increase as more years of Energy Smart investments are layered in, but I do not think it is fair to state categorically that contemporaneous recovery as expense under EECR will be inherently less costly to customers than the Company's proposal. As I noted, the Company's proposed Rider DSMCR will be less costly to customers initially because it spreads recovery over multiple years as well as incorporates beneficial tax effects. That point should be without dispute, but I have attached workpapers to my Rebuttal Testimony that demonstrate this fact. I have also provided workpapers and analyses testing Mr. Prep's assumption that recovery through Rider EECR will be less impactful to customers' bills than recovery through Rider DSMCR.

Q23. PLEASE DESCRIBE THESE WORKPAPERS AND THE ANALYSES THEY REPRESENT IN MORE DETAIL.

A. The workpapers attached to my Rebuttal Testimony provide a view of how recovery of estimated Energy Smart costs through the Company's proposed Rider DSMCR compare to recovery of those same costs through the EECR. To achieve this comparison, the model depicts the revenue requirement for Energy Smart costs under each proposal over a five year period, from 2020 to 2025 in both nominal and present value figures (note that the net present value calculations for DSMCR go out to 2028 because of amortization of each year's DSM investments). The modeling includes several simplifying assumptions to address unknown variables that the Council has yet to determine with regard to Program Year 10 and beyond. For illustrative purposes, those assumptions include the following:

- Program costs are assumed to be $15 million in 2020 and increase by $1 million per year for each subsequent year through 2025, consistent with what Mr. Prep describes as current Council policy;[15]
- Program costs as budgeted are assumed to equal actual investment for each Program Year, eliminating the operation of any true up mechanism from the models;
- For EECR, the Utility Performance Incentive ("UPI") amounts remain the same as those established in Council Resolution No. R-18-228 – this is a very conservative assumption that likely understates the overall cost of the EECR recovery method, as Mr. Prep stated in his deposition that it is likely the UPI amount would increase under his proposal consistent with higher anticipated DSM investments;[16]
- The model assumes LCFC has been addressed appropriately and adequately by another Council-approved mechanism, such as an FRP that takes into account future lost sales, as Mr. Thomas describes;
- In one scenario, ENO achieves 95% of savings targets for each year (thus earning no performance-based return-on-equity ("ROE") adder incentive under Rider DSMCR) and in a second scenario, ENO achieves in excess of 120% of savings targets each year (thus earning a 200 basis point ROE performance incentive); and
- Net Present Value ("NPV") calculations are performed using an after-tax weighted average cost of capital ("WACC") (or Authorized Return on Rate Base) for the Company of 7.78%.

Q24. WHAT DO THE RESULTS OF THE ANALYSES DEMONSTRATE?

A. The analyses demonstrate that recovery of Energy Smart costs through Rider DSMCR has significantly less of a rate effect on customers than recovery through Rider EECR in 2020 and 2021. This is, in part, because Rider DSMCR spreads out cost recovery over a longer period of time than does Rider EECR, which recovers all costs in a single year. A secondary benefit of spreading out cost recovery is that Rider DSMCR takes into account accumulated deferred income tax ("ADIT")

[15] Prep Deposition at 93.

[16] *Id.*

treatment. In 2022 and each subsequent year, Rider DSMCR still has a lower revenue requirement than Rider EECR, but the gap narrows for the reasons I described above and in my Revised Direct Testimony. The charts below provide a graphic depiction of this outcome for both the 95% scenario and the 120% scenario.

<u>Figure 1</u>: Annual Revenue Requirement for DSMCR
Compared to EECR, 95% of Savings Targets:

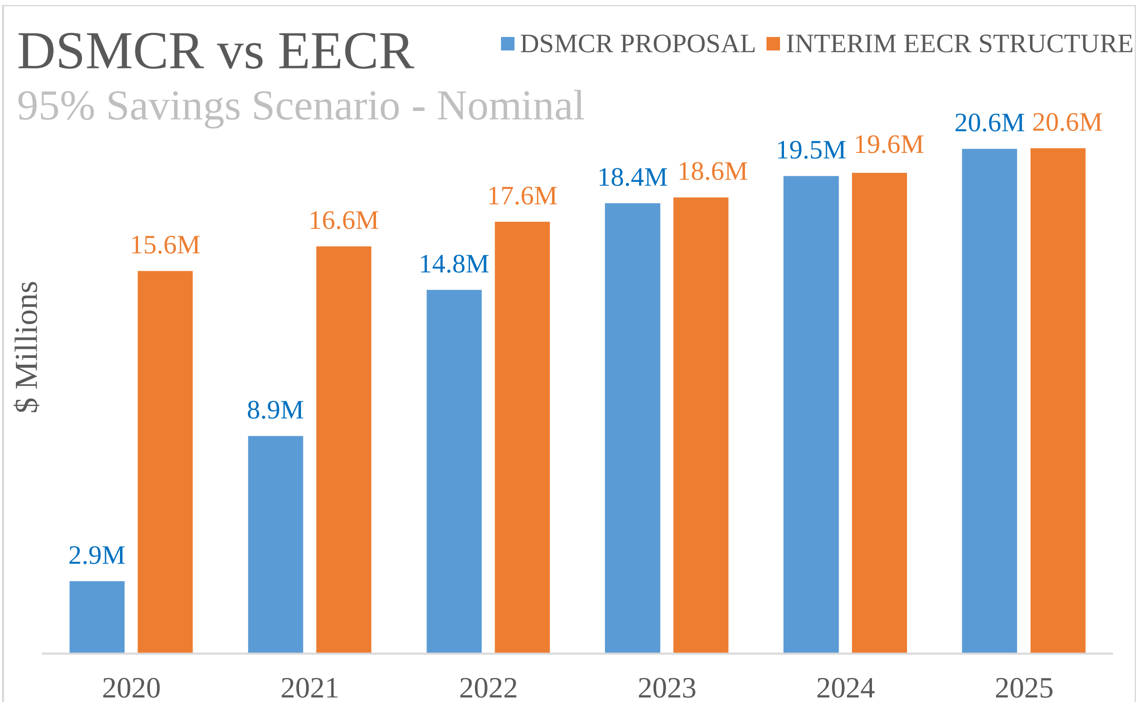
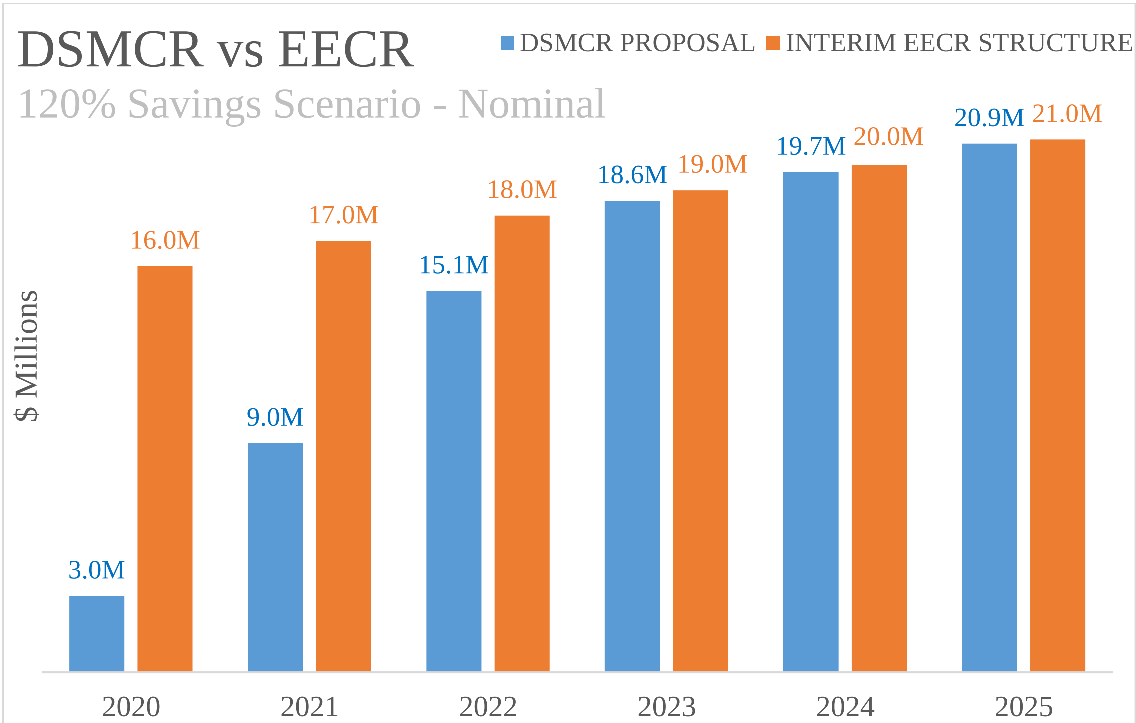


Figure 2: Annual Revenue Requirement for DSMCR
Compared to EECR, 120% of Savings Targets:



While the two figures above show nominal cost recovery each year for 2020 through 2025, calculating an NPV for each scenario requires going out to 2028 for DSMCR to capture the end of the amortization period for each year of DSM investments. The NPV calculation also demonstrates that customers are better off under Rider DSMCR given how recovery of DSM investments are spread out over time. The following tables compare total nominal and NPV values for DSCMR and EECR for each scenario. The two figures above and the NPV results both demonstrate that Rider DSMCR will actually have less of an effect on customers than Rider EECR, contrary to Mr. Prep's assumption.

Table 1. Comparison of DSCMR to EECR for 2020 to 2025 (95% Scenario).[17]

Mechanism	Nominal	NPV
DSMCR	$116,491,112	$80,192,159
EECR	$108,600,000	$83,208,849
Delta	$7,891,112	($3,016,690)

Table 2. Comparison of DSCMR to EECR for 2020 to 2025 (120% Scenario).[18]

Mechanism	Nominal	NPV
DSMCR	$118,135,412	$81,358,007
EECR	$111,234,000	$85,251,601
Delta	$6,901,412	($3,893,594)

Q25. DO YOU HAVE ANY OTHER CONCERNS REGARDING MR. PREP'S RECOMMENDATION?

A. Yes. Mr. Prep's recommendation ignores a large part of the reason the Company proposed Rider DSMCR – to place supply and demand-side investments on a more equal footing in terms of return on investment. Mr. Prep's testimony does not address this point at all, despite the Council clearly stating that achieving this parity should be a goal of DSM-related policy in New Orleans and Mr. Prep's own opinion that "aligning utilities' incentives for investing in demand-side resources with incentives for supply-side resources is an important policy goal."[19] To be clear, Mr. Prep stated in his deposition that the Advisors support a monetary incentive for ENO's

[17] The calculation for DSMCR goes out to 2028 to capture the end of the amortization period.

[18] *Id*.

[19] Prep Deposition at 87, lines 6-10.

investments in DSM,[20] but he recommends that the specific amount be determined later in the year.[21] Mr. Prep also seemed to indicate that it could be possible to add an incentive framework to a rider dedicated to Energy Smart funding that is adopted in this proceeding, while determining certain specifics about the incentive when the Council considers the specific goals and budgets for future years of Energy Smart.[22] Given that the Council is attempting to comprehensively consider rates and rate structures in this proceeding, ENO recommends that the Council not defer its decision on the right kind of incentive structure for accomplishing its overarching policy goals related to Energy Smart.

Finally, Mr. Prep's recommendation to include EECR costs in the annual FRP evaluation would mean that Energy Smart costs may be under- or over-recovered given the potential interplay with the FRP bandwidth, if he is suggesting that the EECR mechanism would not include some form of annual true-up. In other words, if there is no annual true-up mechanism in the EECR Rider, and EECR revenues in any given year were less than the amount of Energy Smart program costs, but the FRP evaluation results were within the bandwidth, no rate adjustment would occur, and ENO would not recover all of the Energy Smart costs for that year.[23] Such treatment is inconsistent with the first principle of DSM cost recovery (recovery of DSM program costs), is inconsistent with the expectation that having a rider provides

[20] *See id*. 89-92.

[21] *See id*. at 87-95.

[22] *See id.* at 95-97.

[23] The opposite could just as well occur – ENO may over-recover EECR costs absent a true-up mechanism and synchronization in the FRP as described further by Mr. Klucher.

timely recovery, and it would not signal robust Council support for ENO's efforts to implement increased Energy Smart investments and pursue aggressive savings targets.

Q26. DO OTHER WITNESSES ADDRESS THE IDEA THAT DEMAND-SIDE RESOURCES REQUIRE SOME FORM OF INCENTIVIZATION TO BE PLACED ON A LEVEL PLAYING FIELD WITH SUPPLY-SIDE RESOURCES?

A. Yes. Alliance witness Mr. Justin Barnes seems to agree with me and Dr. Faruqui that addressing the inherent challenge presented by utility investments in DSM is crucial. Further, all three of us, along with Mr. Prep, seem to agree that a core element of promoting investments in DSM is incorporating some form of a performance incentive. Yet, Mr. Barnes does express some skepticism related to Rider DSMCR and recommends certain modifications to the performance incentive framework ENO has proposed. Additionally, Mr. Barnes makes criticisms of Rider DSMCR related to decoupling and the treatment of LCFC, which I have already addressed above, and which Mr. Thomas addresses in the context of the Company's recommended modifications to the FRP to address LCFC. Mr. Barnes also criticizes the Council-approved allocation method (percentage of base rates) that ENO embedded in Rider DSMCR.

Q27. ON WHAT GROUNDS DOES MR. BARNES EXPRESS SKEPTICISM CONCERNING RIDER DSMCR, AND HOW WOULD YOU ADDRESS HIS CONCERNS?

A. Mr. Barnes expresses skepticism about Rider DSMCR by criticizing the regulatory asset recovery model and the examples of successful implementation of this model in other jurisdictions as some kind of scheme devised by utilities for their own exclusive benefit. He also claims that the regulatory asset model and incentive mechanism proposed by ENO "distorts the playing field in the utility's favor rather than leveling it."[24] I will address each point in turn.

On the first point, I would note that there are recent examples where progressive regulators are looking beyond traditional notions and definitions to find creative solutions to get to "win-win" outcomes for customers and utilities. A good example has been regulators looking at how to address cloud computing expenses relative to traditional utility investments in information technology infrastructure.[25] I see the Company's proposed Rider DSMCR in much the same way; as an innovative model (which, as Dr. Faruqui notes, is an emerging trend) that will create a positive framework for the Company to significantly expand its Energy Smart investments in the coming years to benefit customers.

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[24] *See* Direct Testimony of Justin Barnes at 40-41.

[25] *Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements*; Adopted by the NARUC Committee of the Whole on November 16, 2016.

Despite the recent examples provided by Dr. Faruqui, Mr. Barnes claims that using a regulatory asset-based approach is "relatively uncommon."[26] He goes on to criticize the regulatory asset model by alleging that it has primarily been proposed by other utilities. He also critiques the examples Dr. Faruqui cites by focusing on other aspects of the enacting legislation with which he disagrees, but that have nothing to do with incentivizing demand-side management activity (*e.g.*, treatment of nuclear plant costs, potential effects on net-energy metering, etc.). Mr. Barnes's criticisms of the regulatory asset model in this regard seem to focus not on the technical merits of the model or its ability to facilitate the Council's policy goals (which is where my Testimony and Dr. Faruqui's Testimony focus), but rather on criticizing the model as "something that utilities want."[27]

Criticizing rate-based recovery of DSM investments on the grounds that utilities like the approach misses the point entirely. As Dr. Faruqui has shown, progressive regulators (including the Council)[28] and innumerable DSM policy advocates recognize that innovative recovery mechanisms that make DSM investments attractive to utilities are necessary to actualize the full, cost-effective potential of demand-side resources. ENO's proposed Rider DSMCR is based on careful consideration of (i) the Council's prior expressions of policy goals for demand-side resources, (ii) the Council's desires for the future performance of Energy Smart, and (iii) emerging industry trends and best practices from progressive

[26] Barnes Direct at 39-40.

[27] *Id*. at 40.

[28] *See, e.g.,* Resolution No. R-07-600.

regulators that present "win-win" solutions. Based on these efforts, ENO went to great lengths in its September 2018 filing to show the necessity for a new approach to address what are expected to be substantial future investments in DSM. ENO is ready and willing to embrace the Council's push for more sustainability-oriented resource portfolios – portfolios that, among other things, maximize the cost-effective potential of demand-side resources. ENO proposed Rider DSMCR to facilitate this very outcome, and to do so in a way that provides a fair return on the substantial investments required to accomplish these goals. Dismissing ENO's proposed model out of hand simply because ENO proposed it and because other utilities and regulators that share the Council's progressive policy goals have seen success with it will not advance the Council's goals nor benefit the residents of New Orleans.

Mr. Barnes also makes an argument with a similar theme when he criticizes Rider DSMCR not on its merits or technical aspects but by asserting that "the stick is sometimes more effective than the carrot."[29] I do find this line of attack disappointing because it undermines a view of utility regulation where collaboration is a foundation to identifying a model that will provide a "win" for all stakeholders. Moreover, as Dr. Faruqui notes, Mr. Barnes assertion is not accurate. Under the Company's proposed Rider DSMCR, the return earned on the regulatory asset balance for a particular year of DSM investments would be adjusted higher or lower in order to reward or penalize the Company for performance. Performance in this context refers to successfully administering Council-approved, cost-effective DSM

[29] Barnes Direct at 48.

measures through Energy Smart and having the resulting benefits to customers confirmed through a third-party Evaluation, Measurement, and Verification ("EM&V") process. As I discuss further below, these Council-required processes, with which Mr. Barnes seems to have little familiarity, would work in conjunction with Rider DSMCR to help ensure that the Company does not earn a reward unless it is creating value for its customers – making Rider DSMCR a potential "win-win" solution for the Council, ENO's customers, and ENO. In my view, looking to create that "win-win" outcome, rather than for a "stick" would be a more productive use of everyone's efforts.

Q28. PLEASE ADDRESS MR. BARNES'S SECOND ARGUMENT ABOUT RIDER DSMCR AS TILTING THE PLAYING FIELD IN THE UTILITY'S FAVOR, RATHER THAN LEVELING IT.

A. Mr. Barnes's argument seems to miss the point as to what the "playing field" at issue actually is: the financial treatment of utility investments in supply-side and demand-side resources made to benefit customers. My Revised Direct Testimony, and that of Dr. Faruqui, explains that utilities typically earn a return on the capital they prudently invest in supply-side resources. In order for the "playing field" to be leveled, utilities should also be allowed to earn on prudently-incurred demand-side resources. The example Mr. Barnes uses in attempt to prop up his unsubstantiated assertion about a tilted playing field seems to miss this point entirely. Mr. Barnes asserts that because DSM investment can avoid energy and capacity costs resulting in savings to customers (which is part of what can make DSM investments cost-effective), allowing ENO to earn a return on the investment required to produce those savings is somehow a double-counting in the utility's favor. In other words, he argues that because a utility would not earn a return on energy costs that DSM investments can help to avoid, the utility should not earn a return on the investment required to avoid those costs. This convoluted argument does not withstand scrutiny.

As ENO's discovery response to request AAE 3-7 noted,[30] investments in supply-side assets can often produce reduced fuel costs; that benefit is part of what makes them net-beneficial, cost-effective, and prudent. The return earned on such investments is on the capital investment in total, not the investment net of the avoided or reduced fuel costs that would have been incurred had the investment not been made. So, to level the playing field between supply- and demand-side investments, incentive mechanisms should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset. Rider DSMCR does this in a relatively straightforward way by providing a mechanism for ENO to earn a return on investments in cost-effective DSM resources (which the Council has indicated should be prioritized) and **not** a return on the avoided costs that contribute to those resources being cost-effective in the first place. Mr. Barnes' example goes to great lengths to obscure this fact in an effort to paint ENO's proposal as unreasonable, or "too rich."[31] Once again, Mr. Barnes seems to engage in verbal

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[30] Exhibit DAO-7.

[31] Barnes Direct at 48.

gymnastics to find imaginary flaws with Rider DSMCR, simply because ENO is the party that has proposed it.

Q29. YOU MENTIONED THAT MR. BARNES HAD SOME SPECIFIC CRITICISMS ABOUT THE MECHANICS OF THE INCENTIVE MECHANISM EMBEDDED IN RIDER DSMCR. WHAT ARE THOSE CRITICISMS AND HOW DO YOU ADDRESS THEM?

A. Mr. Barnes first argues that the approach is "too rich, effectively providing a shareholder return regardless of the amount of savings achieved relative to the target."[32] It appears to me that Mr. Barnes conflates the ability to earn a return under DSMCR with the Company's proposed incentive, which adjusts the level of return. Mr. Barnes argues that "there should be a reasonable minimum threshold at which no incentive is allowed."[33] Mr. Barnes then argues that the Company's proposal to adjust the level of return does not adequately tie performance to the incentive. Mr. Barnes then makes three suggestions,[34] which I will address one-by-one.

First, Mr. Barnes recommends that a minimum savings threshold be set below which no additional earnings would be received, such as meeting 80% of an annual target; he also suggests that there be the potential for penalties for "unreasonably poor performance."[35] In his first recommendation, Mr. Barnes uses the term "additional

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32 *Id*.

33 *Id*.

34 *See* Barnes Direct at 49.

35 *Id*.

earnings," which I find confusing. It is not clear to me if he is suggesting that the return be reduced below the level the Company proposes (a reduction of Rider DSMCR's allowed ROE by 100 basis points if the Company falls below 60% of the savings goal for a given year), or if Mr. Barnes is proposing that below his example 80% threshold, the return would be set lower, potentially even to zero. If that is in fact what he is suggesting, my view is that such treatment would be unfair and completely inappropriate because, as I noted on pages 24-25 of my Revised Direct Testimony, the Company's pre-tax WACC, which forms the basis for the earnings on the regulatory asset, includes debt that must be repaid to bondholders. Thus, not only would ENO be deprived of the ability to pay a reasonable return to equity holders who invest in ENO – a result in and of itself that would discourage investment in ENO – ENO would also be unable to recover the monies it borrows from bondholders – a result that would make it much more difficult, and costly, for ENO to borrow money. Moreover, the attendant investment is made in measures that have been approved by the Council. Absent some imprudence on the part of the Company in administering or executing the Council-approved DSM portfolio, ENO should be able to recover its cost of the capital that it invests in DSM to benefit customers. As such, the "penalty mechanism" ENO has already proposed to include as part of Rider DSMCR, which I described in my Revised Direct Testimony and summarized above, should be more than sufficient to address Mr. Barnes's concern.

Regarding Mr. Barnes's contention that there be some form of "penalty," I would note that the Council always retains the right to look at the prudence of the Company's DSM investments. If, for example, as part of the after-the-fact annual

EM&V review and true-up process, the overall cost-effectiveness of a given year's portfolio falls below a Total Resource Cost ("TRC") score of 1.0, the Council has discretion to address the matter and could disallow recovery of investments that it determines to be imprudent. That authority and ability serves in and of itself as a means to impose a penalty. I would add that overall cost-effectiveness for a given year's DSM investments is a function of the level of investment, the resulting energy and capacity savings, and the agreed-upon methodology and avoided costs to be used in the evaluation. Today, the Company optimizes its management of Energy Smart investments each year to achieve the highest level of cost-effectiveness through maximizing savings and managing the level of investment necessary to yield those savings.

Mr. Barnes's second recommendation with respect to the performance incentive is that a more gradual approach be used (*e.g.*, 5% increments). The Company's proposed performance incentive is consistent with the most recent methodology employed with Energy Smart, which served as the basis for what was included in Rider DSMCR. Nonetheless, Mr. Barnes makes a reasonable point and the Company's proposal can be modified to be more granular. For example, rather than using a 100 basis point adder for results that fall between 95% and 120% of a target level of savings, a more granular performance incentive could be used. For example, each 5% level for that same range could involve a 20 basis point adder where, for example, achieving 100% of target would results in adding 20 basis points to the allowed ROE. Although I provide one example, the Company would have to redesign its proposal should the Council show preference for a more granular performance incentive.

Mr. Barnes's final recommendation is that the Council consider "capping" the performance incentive amount using some metric. My response is that there will be a cap, namely the cap is effectively the highest adjustment that would be applied to the allowed ROE that the Council approves that would be used for a given year's DSM investments. There is no reason to add an additional layer of complexity and administrative burden with yet another cap. And as I noted above, the Council always has the ability to challenge the prudence of an investment whether it be in DSM or a supply-side resource.

V. COMMUNITY SOLAR

Q30. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S COMMUNITY SOLAR PROPOSAL.

A. ENO proposes to use solar photovoltaic ("PV") resources in the City that either already exist or are under development and will soon exist[36] to offer a voluntary option to its customers starting January 2020. Under the Company's proposed Rider Community Solar Option ("CSO"), a participating customer would see a monthly charge tied to their respective share of the aggregate capacity of solar PV resources, and, in return for that charge, would receive an offsetting bill credit. Under this "pay-as-you-go" model, the monthly charge would stay fixed for as long as the customer

[36] Council Resolution No. R-18-222, dated June 21, 2018 approved the construction of the 5 MW distributed—generation scale solar PV project that ENO proposes to support the CSO offering.

participates, whereas the bill credit would change each month in relation to any change in base rates as well as the Company's monthly fuel adjustment clause.

Q31. APPROXIMATELY WHEN DID THE COMPANY BEGIN CONSIDERING DEVELOPING A COMMUNITY SOLAR OPTION?

A. The Company's efforts began well before the instant rate case was filed. For example, I became involved in assisting ENO with the development of its 1 megawatt ("MW") Paterson solar + battery pilot project in 2015. Community solar was considered in conjunction with that project but ultimately determined to be premature given the pilot nature of the project. Still, the Company continued to evaluate opportunities for developing a community solar offering, and in early 2016, ENO pursued a bid in its 2016 Renewable Request for Proposals ("RFP") for the 5 MW rooftop solar self-build project that was ultimately approved by the City Council in June 2018.[37] When that project was conceived, there was consideration whether it could be used to support a new community solar offering.

Also, in early 2016, I was heavily involved with drafting a report on community solar that was filed in July 2016 with the Mississippi Public Service Commission ("MPSC"), which I am attaching as Exhibit DAO-8. The ideas outlined in that July 2016 report formed the basis for what the Company would eventually propose in Rider CSO. In fact, in conjunction with the Council's review of the 5 MW rooftop solar project that occurred in early 2018, the Company provided different

[37] Council Resolution No. R-18-222.

approaches for using the project to support a separate community solar offering. Prior to that review process, I had separately begun working with ENO on the development of the offering embodied in Rider CSO in late 2017. All of these efforts related to formulating a workable community solar concept pre-date the initiation of the Council's rulemaking in June 2018 (Docket No. UD-18-03).

Q32. WHAT IS THE CURRENT STATUS OF THE COUNCIL'S RULEMAKING IN DOCKET NO. UD-18-03?

A. The Community Solar Rulemaking was initiated June 2018 (just prior to the initial rate case filing in July 2018), and the Company has been an active participant.[38] In December 2018, the Council's Utility, Cable, Telecommunications and Technology Committee ("UCTTC") voted to adopt the rules as then-proposed by the Advisors in Council Resolution No. R-18-538. As of the date of this filing, the full Council has not yet voted to enact final rules regarding community solar projects.

Q33. IF THE FULL COUNCIL ADOPTS RESOLUTION R-18-538, WILL THE COUNCIL'S COMMUNITY SOLAR INITIATIVE THEN BE OPEN TO CUSTOMER ENROLLMENT AND PROJECT DEVELOPMENT?

A. It does not appear so. Once Resolution R-18-538 is adopted by the full Council, a subsequent phase of the rulemaking proceeding will begin. This subsequent phase will allow for comments from the parties concerning Section XIV of the draft rules,

[38] Council Resolution R-18-223 established Docket No. UD-18-03 and opened a rulemaking to consider establishment of rules for community solar projects.

which describes how the rules should be enforced and how the Council's initiative would be administered by the Council's Utility Regulatory Office ("CURO"). The resolution also requires the Advisors and CURO to submit a joint report detailing (i) proposed changes to the rules resulting from the to-be-filed comments of the parties, (ii) an estimate of what additional personnel CURO would need to undertake the new duties set forth in the rules, (iii) estimates of the additional budget CURO would need to perform these functions, and (iv) drafts of new forms and procedures CURO will need to employ to perform its new functions. After the conclusion of this phase of the proceeding, the Council would presumably adopt a complete set of rules for its initiative. It is unclear to me how much time would be required for CURO to obtain additional funding and hire additional staff that may be required to administer the initiative and open up enrollment for customers and the registration vetting of project developers.

Separately, once the full Council adopts Resolution R-18-538, ENO will be required to begin a process of working with the Advisors and stakeholders to develop the internal capabilities to administer the Council's initiative. This process will involve the creation of a Community Solar Administration Plan, a Standard Interconnection Agreement for community solar facilities, and appropriate tariffs. Resolution R-18-538 also provides for stakeholder comment on these documents. Presumably, the Council will also need to approve the Plan, Interconnection Agreement, and tariffs before the Council's initiative is open for business.

Q34. WHAT CONCERNS DO THE COUNCIL'S ADVISORS RAISE?

A. The concerns raised by the Advisors witnesses Joseph Rogers and Victor Prep all appear to relate to potential interplay between the Company's proposed Rider CSO and the Council's proposed initiative.

Q35. WHAT ARE MR. ROGERS'S CONCERNS?

A. Mr. Rogers quotes language in the proposed community solar rules that "to the extent ENO chooses to become a community solar developer, it must offer the same privileges it allows itself to all other developers. ENO may not give itself preferential treatment as a developer of a community solar project, and it may not use ratepayer funding for its community solar projects in any manner not available to other developers."[39] Mr. Rogers then goes on to state that ENO's proposal is not in conformance because (1) the underlying revenue requirement for the Company's solar PV resources will already be reflected in rates as opposed to being covered only by participating customers and (2) the Company proposed a bill crediting mechanism using embedded generation and fuel costs as opposed to using MISO-based capacity and energy costs. Mr. Rogers then recommends that the Council either (i) reject the Company's proposal and require the Company to justify (in a separate proceeding) why its proposal should be approved in its present form, or (ii) conform its proposal to the Council's draft rules.

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[39] *See* Council Resolution R-18-223 at 3.

Q36. DOES ADVISORS WITNESS PREP RAISE ANY ADDITIONAL ISSUES REGARDING ENO'S PROPOSED RIDER CSO?

A. Advisors witness Prep takes issue with my characterization that Council Resolution R-18-222 appears to support the Company proposing community solar using the 5 MW rooftop solar PV resources, but he generally discusses the same two issues that Mr. Rogers raises in his testimony.

Q37. WHAT IS YOUR RESPONSE TO THE FIRST CONCERN RAISED BY THE ADVISORS RELATING TO THE PENDING RULES?

A. My Revised Direct Testimony expressly acknowledged that the Company's proposed Rider CSO is not in conformance with the draft rules, nor was it intended to be, as the Company's efforts to develop Rider CSO predated the proposal for a Community Solar Rulemaking. ENO's filings in Docket No. UD-18-03 also acknowledged this fact and expressed the hope that the Council would consider multiple avenues for the adoption of community solar initiatives, rather than limiting the options available to New Orleans residents. As I noted above, the Company began exploring how best to offer community solar to customers well in advance of June 2018 when the Council initiated its community solar rulemaking. The Company acknowledges that to the extent it develops one or more <u>new</u> solar PV resources dedicated for community solar, that it complies with whatever rules and requirements ultimately come from the Council's pending rulemaking. But until those rules become final and the Company acting as a "developer" actually proposes a new community solar project, the Company's customers that are interested in having more renewable energy-related options now should be provided that opportunity if one is reasonably available. Moreover, I do not believe it is fair for ENO's proposal for Rider CSO to be disadvantaged by a retroactive application of rules that the full Council has yet to adopt as of the filing of ENO's proposal or even this testimony. Further, while Mr. Rogers suggests the Council could require the Company to further justify Rider CSO in a separate proceeding, I would argue that the Company attempted to do exactly that in its initial filing in the instant Docket and is entitled to an adjudication on the merits of its proposal in this proceeding and based on any regulatory requirements that existed at the time the proposal was filed.

Q38. WOULD CUSTOMERS THAT MAY ULTIMATELY PARTICIPATE IN THE COUNCIL'S PROPOSED COMMUNITY SOLAR INITIATIVE BE HARMED IF ENO'S PROPOSED RIDER CSO WERE "GRANDFATHERED," OR DID NOT HAVE THE COUNCIL'S COMMUNITY SOLAR RULES RETROACTIVELY APPLIED TO IT?

A. No, they would not. If the Council's community solar initiative ultimately attracted developers, customers would be free to enroll in any resources offered by those parties without incurring any penalties. In fact, I would argue that allowing ENO's proposal for Rider CSO to proceed could actually create benefits for any developers or subscribers that choose to participate in the Council's initiative by allowing ENO to gain experience with the administration of a community solar offering before the Council's initiative gets under way. Allowing ENO's Rider CSO to move forward may also help to reduce the incremental costs of ENO's administration of the

Council's initiative (*e.g.*, programming the CCS billing system), which would in turn benefit participants and developers of the Council's initiative, who would ultimately be responsible for bearing incremental costs associated with the effort.

Q39. ASSUMING THE COUNCIL EVENTUALLY ADOPTS THE RULES RECOMMENDED IN RESOLUTION R-18-538 AND APPLIES THEM TO ENO'S PROPOSAL, WHAT WOULD THOSE RULES REQUIRE THE PROPONENT OF A COMMUNITY SOLAR OFFERING THAT DOES NOT CONFORM TO RULES PROPOSED THEREIN TO DEMONSTRATE TO THE COUNCIL TO GAIN APPROVAL OF A NON-CONFORMING PROJECT?

A. The draft of Resolution R-18-528, as adopted by the UCTTC in December 2018, states that "proposals that do not conform to the Community Solar Rules, or proposals that seek a waiver of one or more of the Community Solar Rules would need to be submitted to the Council for review and approval."[40] The resolution also states that the proponent of proposals that do not conform to the rules would need to "demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules would bring."[41]

[40] *See* Resolution R-18-538 at 30-31.

[41] *Id.*

Q40. HAS ENO SUBMITTED RIDER CSO TO THE COUNCIL FOR "REVIEW AND APPROVAL?"

A. Yes, with the application filed in the instant Docket.

Q41. DOES THE PROPOSAL SUBMITTED BY ENO FOR REVIEW AND APPROVAL IN THIS DOCKET PROVIDE GREATER POTENTIAL BENEFITS TO CUSTOMERS THAN A PROPOSAL CONFORMING THE YET-TO-BE-ADOPTED COMMUNITY SOLAR RULES WOULD OFFER?

A. Yes, in my opinion ENO's proposal provides benefits that projects conforming to the proposed rules cannot provide. Many of these unique benefits result from the fact that ENO is a regulated, vertically-integrated utility that can offer "Utility-Scale" community solar projects.

First, because ENO is already subject to the regulatory authority and mechanisms of the Council, ENO's proposal would not require the Council and CURO to develop additional regulatory mechanisms for the oversight of ENO's proposed Rider CSO. In contrast, Resolution R-18-538 acknowledges that CURO will need to hire additional staff and request additional funding from the City budget to accommodate projects developed under the proposed rules; all residents of New Orleans would bear these costs either through taxation or utility rates that fund CURO. New Orleanians would not see these kinds of increased costs under ENO's proposed Rider CSO.

Second, as ENO stated in its comments in Docket No. UD-18-03, the option for customers to participate in "Utility-Scale" offerings could help to offset the revenue requirements associated with ENO's commitment to add up to 100 MW of renewable energy to its generation portfolio and, as such, would fulfill an objective for this rulemaking that was agreed to by several parties as part of the Council's approval of the construction of ENO's 5 MW Distributed-Generation scale solar project.[42] Finally, both Mr. Rogers and Mr. Prep appear to acknowledge that approval of the Company's proposal would likely mean that customers would have a community solar option in a more timely manner relative to what might occur under the Council's proposed community solar rules should those be eventually adopted.

Q42. HAVE ANY OTHER STAKEHOLDERS COMMENTED ON THE COMPANY PROPOSING A COMMUNITY SOLAR OPTION SEPARATE AND APART FROM THE PENDING RULES?

A. Yes. In Reply Comments filed by the Alliance in Docket No. UD-18-03 on October 31, 2018, the Alliance stated:

> "As for parallel tracks for ENO's proposed Community Solar Offering within their rate case, filed on September 21, 2018, the Alliance's position is to allow both tracks to continue. As long as the rules in the instant docket are not "held up" by the conclusion of Council Docket UD-18-07, we see no reason to insist that these rules impact the utility's Community Solar mechanism in that docket. The mechanism described in ENO's rate case application envisions a more flexible offering than the community solar projects contemplated in these rules, with customers less "locked in" to a long-term commitment. This may well be one of the kinds of benefits the utility's considerable resources

[42] *See* Resolution R-18-222 at 11. ("[T]he Settling Parties agree that, the subject of voluntary, subscription-based customer participation in renewable resource programs should be examined by the council in a future regulatory proceeding in which all parties will be afforded the opportunity to participate and provide comments and other input for consideration by the Council, and that **such a proceeding may result in the development of a mechanism <u>*or mechanisms*</u> by which voluntary customer participation helps to offset a portion of the cost of the [5 MW] Project and or other renewable resources**.") (Emphasis added.)

> can provide that developers cannot, and may be a reason to create separate tracks. However, any rules related to the function, administration, reporting, and consumer protections that are finalized within this docket must apply equally to the Company."

If approved, the Company believes that Rider CSO will feature the necessary oversight from the Council regarding reporting and consumer protections that the Alliance suggests be applicable.

Air Products and Chemicals, Inc. also suggested in its Reply Comments filed in the same Docket on October 31, 2018, that ENO's community solar offering be separately considered for approval in the 2018 Combined Rate Case as opposed to within the context of the Council's pending community solar rules.

Q43. WHAT IS YOUR RESPONSE TO THE SECOND CONCERN RAISED BY THE ADVISORS RELATED TO THE CREDIT RATE?

A. As I noted above, the Company began developing its "pay-as-you-go" model along with different approaches to address the credit rate well before the Council initiated its rulemaking in June 2018. The Company's proposal to use a credit rate based on embedded generation and the monthly fuel adjustment clause was deliberate. That said, without knowing what kind of bill credit framework the Council may ultimately adopt,[43] it is not possible for me to comment further on the Advisors' concerns about the potential difference between Rider CSO's compensation mechanism and one that may be adopted by the Council in Docket UD-18-03. If and when the full Council

[43] While the UCTTC adopted a credit mechanism and framework in December 2018, based on my attendance of that meeting, I understand that the UCTTC is considering possible modifications to that mechanisms before advancing the Community Solar Rules to the full Council for approval.

settles on a bill credit mechanism for its community solar rules, it may be possible for me to more fully address the Advisors' concerns in this regard.

Q44. DO YOU HAVE ANYTHING ELSE TO ADD ABOUT THE COMPANY'S COMMUNITY SOLAR PROPOSAL?

A. I want to reiterate that the Company's proposal, which has been under development for many years and ultimately included with the Company's original 2018 base rate case filing in July 2018, provides a reasonable near-term community solar option for customers. ENO's proposal would not interfere with future projects developed under the Council's final rules. Further, the insight gained through this near-term, small community solar offering could prove valuable in developing later projects under the auspices of the Council's final rule. I think it would be counterproductive and a wasted opportunity to reject the Company's proposal. I would also add that, even if the Council's rules are adopted and applied to ENO's proposal, ENO's proposal meets the requirements for a Community Solar offering that does not conform to those rules. ENO has made a separate filing for approval of Rider CSO in this proceeding and has demonstrated why Rider CSO would provide greater potential benefits as it is structured than if it conformed to the Councils (draft) rules. I believe ENO proposed Rider CSO is entitled to an adjudication on the merits in this proceeding and hope that the Council will give full and fair consideration to the proposal.

VI. EV CHARGING INFRASTRUCTURE

Q45. PLEASE BRIEFLY DESCRIBE THE COMPANY'S EV CHARGING PROPOSALS.

A. The Company proposed two different ideas with the first one being a new EV Charging Infrastructure ("EVCI") rider that would foster investment in charging infrastructure on customer-owned property with the customer paying for the investment through a monthly charge on their electric bill. The second proposal was for ENO to invest up to $500,000 in constructing utility-owned and operated EV chargers that would be located on City of New Orleans property for public use. With respect to the two proposals, Advisors witness Byron Watson recommends that the EVCI rider be approved, but that the Council reject the Company's proposal to invest in public charging infrastructure and instead that the matter be taken up in a forthcoming EV-specific proceeding. Mr. Watson appears to raise two different concerns related to the public EV charging proposal in his testimony.

Q46. WHAT IS YOUR RESPONSE TO THE FIRST CONCERN RAISED BY MR. WATSON REGARDING INVESTMENT IN PUBLIC CHARGERS?

A. As I appreciate it, Mr. Watson's first concern is that I recommended in my Revised Direct Testimony that the Company not initially charge the public for EV charging in instances when the charger is not located behind an existing electric meter. For example, this situation might apply if ENO were to install several EV chargers on one of the sidewalks adjacent to City Hall and the chargers were not tied in behind the property's electric meter. To be clear, I am not suggesting that the parking space be free, only that the use of the charger by an EV while the vehicle is parked not be charged a fee.

Mr. Watson performs an estimate using several assumptions and arrives at a figure of $64,432 potentially being socialized to all customers through unaccounted for energy in the fuel adjustment. I accept Mr. Watson's contention that some level of cost would be socialized to all of ENO's customers under what the Company has proposed, but I believe his estimate is higher than it would be, particularly early on given the relatively small number of EVs on the road. Many, if not most, of the EV chargers that would be constructed will likely be located behind existing electric meters where the City would be billed for any usage. The City could, in turn, either charge EV drivers something extra for having access or possibly work with the Company to develop a method to charge EV drivers such that any incremental electricity costs incurred by the City for electricity usage were offset by charging the EV driver.

Second, Mr. Watson assumes all 40 (using the midpoint of the 30 – 50 chargers that might be constructed for $500,000) would be in use 50% of the time or; put another way, 12 hours per day, seven days a week, 52 weeks a year. While I cannot predict consumer behavior, that seems like an unrealistically high level of utilization. While we will not know how EV drivers will use the chargers until we make them available, my sense is that the amount of socialized cost per year would end up being a fraction of what Mr. Watson estimated. And if the Council were to approve the proposal, but order ENO to develop a method of charging EV drivers for using the public chargers that are not located behind an electric meter, the Company would develop a methodology for charging EV drivers (*e.g.*, by time spent charging).

Mr. Watson goes on to argue that ENO not charging an EV driver for using the equipment could hinder future competition in the EV charging marketplace, but suggests that if the EV charger(s) were to be located behind the customer's meter, then the issue would be moot even if the City in this instance chooses not to charge the public anything extra beyond the customary charge for parking (if any). I am not sure that I completely follow the distinction raised by Mr. Watson, but again, if the main issue is a small amount of socialized cost, then I believe the Company can develop a solution to that concern that would allow its proposal to move forward.

Q47. WHAT IS YOUR RESPONSE TO THE SECOND CONCERN RAISED BY MR. WATSON REGARDING INVESTMENT IN PUBLIC CHARGERS?

A. Mr. Watson's second concern involves interplay between the Company's proposal and Council Docket No. UD-18-02 initiated by Council Resolution No. R-18-100[44] that is intended to serve as an information gathering process for various issues related to EVs. Mr. Watson argues that the Company's proposal is more appropriately taken up in that proceeding, which is still playing out as of the date of my Rebuttal Testimony. Most recently, the Company filed its List of Issues for Consideration in the Council's Information Gathering Process Regarding Electric Vehicles in that proceeding on February 28, 2018. While ENO intends to continue actively

[44] Council Resolution No. R-18-536 merged Docket No. UD-18-02 into Docket No. UD-18-01.

participating in that Information Gathering Process, what I would propose is that the issues of investment and collaborating with the City and stakeholders as to where ideally to locate EV chargers be separated. In other words, continue on the current path in this rate case of having the Council determine whether or not it is appropriate for the Company to invest up to $500,000 in public EV charging infrastructure. And then separately use Docket No. UD-18-01 as the forum to engage stakeholders in a collaboration on where best to locate the estimated 30 to 50 Level 2 EV chargers that the Company would construct and operate.

I believe that separating the two issues would provide the timely answer the Company needs on the investment decision while preserving City and stakeholder input on optimal locations. It is also important to note that the State of Louisiana has a significant tax credit that remains available for EV charging infrastructure that the Company can access. As a public entity, the State's EV-related tax credit is not available to the City of New Orleans, and there are no guarantees in the current fiscal environment that it will continue to be available indefinitely. Because there are no guarantees as to when Docket No. UD-18-01 will conclude, nor what decisions might emerge from the Information Gathering Process, it seems that allowing the Company's modest proposal to move forward would be in the best interests of all parties.

Q48. MR. WATSON ALSO MAKES A SUGGESTION ABOUT THE EV CHARGER REBATE INITIATIVE OFFERED VIA ETECH. CAN YOU PLEASE RESPOND?

A. Mr. Watson states that I proposed in my Revised Direct Testimony that ENO offer rebates to its customers for Level 2 EV chargers. As part of a broader beneficial electrification[45] effort, the Company created a website[46] in early 2018 that offers customers a range of incentives ($ rebates) for conversion of equipment that use fossil fuel to electric. For example, the Company offers rebates for conversion of forklifts and other warehouse operations, fleet operations such as trucking and shore power, and of course electric vehicle charging infrastructure. The Company also offers incentives for billboard electrification. In my view, all of these incentives add value for ENO's customers through increased electric sales and many provide environmental and other societal benefits. Given that these efforts are fundamentally designed to encourage conversion to more efficient/less polluting electric alternatives, they will *increase* overall electric sales, and contrary to Mr. Watson's suggestion, I do not believe that Energy Smart is the appropriate forum to evaluate these efforts, the level of spending, or cost recovery. The eTech efforts and associated expenses should be left to operate as-is and in the future recovered as I described via normal ratemaking (*e.g.*, via the Company's proposed FRP if one were to be approved).

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[45] There are various definitions for the term "beneficial electrification;" for example, the Environmental and Energy Study Institute ("EESI") defines it as "a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs." *See* https://www.eesi.org/projects/electrification

[46] *See* http://entergyetech.com/

VII. CONSUMER LOWERED ELECTRICITY PRICING

Q49. HAVE YOU REVIEWED THE TESTIMONY SUBMITTED BY BSI IN SUPPORT OF THE CLEP PROPOSAL?

A. Yes, I have.

Q50. WHAT IS YOUR REACTION?

A. BSI appears to be proposing the same concept that was rejected by the Council in Resolution Nos. R-16-106 and R-17-100. Those Resolutions identified several flaws with the proposed CLEP concept. Based on my review of Dr. Myron Katz's Direct Testimony, it does not appear that BSI has addressed any of the Council's previously-stated concerns. As such, ENO is opposed to the implementation of BSI's proposal.

VIII. CONCLUSION

Q51. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

D. ANDREW OWENS,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

D. Andrew Owens

D. ANDREW OWENS

Sworn to and

Subscribed Before Me

This 15th Day of March, 2019

NOTARY PUBLIC

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

Summary of Decoupling Within the FRP Using Exhibit PBG-8

Step	Description	Component	Residential	%	Line
A	Target Revenue Per Outcome of Rate Case	Fixed	$190,794,569	99.52%	1
		Variable	$918,065	0.48%	2
		Total	$191,712,634	100.00%	3
B	Actual Revenue in TY	Fixed	$189,090,136	99.52%	4
		Variable	$909,864	0.48%	5
		Total	$190,000,000	100.00%	6
C	Adjusted Revenue Requirement for TY per FRP Result	Fixed	$192,131,114	99.52%	7
		Variable	$924,496	0.48%	8
		Total	$193,055,611	100.00%	9
D	Calculate Total Revenue Deficiency (Excess)	Fixed (Ln 7 - Ln 4)	$3,040,978	99.52%	10
		Variable (Ln 8 - Ln 5)	$14,633	0.48%	11
		Total (Ln 9 - Ln 6)	$3,055,611	100.00%	12
E	Calculate FRP % (Ln 12 / Ln 6)		1.6082%		

Notes:
For Illustrative Purposes Only
Sources are Exhibit PBG-8, Myra Talkington Workpaper AA-2,
and Alliance Witness P. Morgan Direct Testimony
No increase in residential customer count occurs during TY (i.e., stays at 181,500)
Total revenue requirement increase per FRP is assumed to be $3m

Alliance Witness P. Morgan Decoupling Methodology Using Exhibit PBG-8

Step	Description	Component	Residential	%	Line
1	Target Revenue Per Outcome of Rate Case	Customer	$33,824,340	17.64%	1
		Energy (Fixed)	$156,970,229	81.88%	2
		Energy (Var.)	$918,065	0.48%	3
		Total	$191,712,634	100.00%	4
2	Actual Revenue in TY	Customer	$33,824,340	17.80%	5
		Energy (Fixed)	$155,265,796	81.72%	6
		Energy (Var.)	$909,864	0.48%	7
		Total	$190,000,000	100.00%	8
3	Calculate Decoupling Revenue Deficiency (Excess)	Energy (Fixed) (Ln 6 - Ln 2)	$1,704,433		10
4	Calculate Decoupling % (Ln 10 / Ln 8)		0.8971%		
5	Adjusted Revenue Requirement for TY per FRP Result	Customer	$33,824,340	17.52%	11
		Energy (Fixed)	$158,306,774	82.00%	12
		Energy (Var.)	$924,496	0.48%	13
		Total	$193,055,611	100.00%	14
6	Calculate Revenue Deficiency (Excess)	Customer (Ln 11 - Ln 5)	$0	0.00%	15
		Energy (Fixed) (Ln 12 - Ln 2)	$1,336,545	99.52%	16
		Energy (Var.) (Ln 13 - Ln 3)	$6,431	0.48%	17
		Total	$1,342,977	100.00%	18
7	Calculate FRP % (Ln 18 / Ln 8)		0.7068%		

EX: 1 DATE 3/14/19
WITNESS: [signature]
NANCY P. RICHMOND, RPR

ENTERGY NEW ORLEANS, LLC.
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the Third Set of Data Requests
of Requesting Party: Alliance for Affordable Energy

Question No.: AAE 3-7 Part No.: Addendum:

Question:

Please refer to the Revised Direct Testimony of Dr. Ahmad Faruqui on p. 6, lines 5-6 stating “The proposal would allow ENO to earn a return on DSM investments and would put DSM on a more level playing field with supply-side opportunities.” in reference to ENO’s proposal to earn a return at its weighted cost of capital on DSM expenses. In reference to the assertion that the proposal would enable “a more level playing field”:

(a) Please state whether Dr. Faruqui agrees or disagrees with the assertion that because DSM expenses produce savings on pass-through expenses such as fuel costs, a portion of DSM expenses effectively reduce costs on which a utility does not earn a return. If applicable, please explain any areas of disagreement with this assertion.

(b) Please state whether Dr. Faruqui agrees or disagrees that ENO’s proposal would effectively allow it to earn a return on avoided variable energy costs that would not produce a return if they were not avoided by DSM expenditures. If applicable, please explain any areas of disagreement with this assertion.

(c) Please state whether Dr. Faruqui agrees or disagrees that ENO’s proposal would effectively allow it to earn a return on avoided variable energy costs that would not produce a return if they were not avoided by DSM expenditures. If applicable, please explain any areas of disagreement with this assertion.

Response:

As explained by Company witness D. Andrew Owens in his Revised Direct Testimony (pp. 23-24), the Council has previously stated that putting DSM offerings on more equal footing with traditional capital investments is desirable and can be in the public interest, and certain stakeholders have agreed.[1] In fact, the Alliance for Affordable Energy supports "fair compensation to the utility" in association with energy efficiency efforts and the modification of the "financial incentive structure generally to resolve the financial tension that has historically led utilities to resist cost effective efficiency programs."[2]

Returns on supply-side capital investments are earned on the entire amount of the investment. To place DSM investments on more equal footing with supply side investments, the incentive earned on DSM investments must also be based on the entire investment, regardless of fuel savings or other benefits that contribute to the investment being cost effective. As an example, consider a utility investment in a combined-cycle power plant. The investment would, all else equal, result in lower fuel costs if the plant has a higher efficiency than existing plants. Fuel costs are passed through to the customer; therefore, such an investment would lower customer expenses related to these fuel costs, which is a factor considered in determining whether the investment is beneficial to customers. However, the return is provided on the entire capital expenditure for the new supply-side resource, not on the capital expenditure net of fuel savings. The same logic applies to demand-side investments. Once the DSM investments have been made, as approved by the Council, the utility should be allowed to earn a return on the entire investment in order to fulfill the Council's goal of DSM investments being placed on a more equal footing with their supply-side counterparts.

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[1] *See* Council Resolution No. R-07-600.

[2] Comments of the Alliance for Affordable Energy (filed January 31, 2018) ("To be clear, we support fair compensation to the utility related to their work with Energy Smart and believe it is important to work with the financial incentive structure generally to resolve the financial tension that has historically led utilities to resist cost effective efficiency programs that deliver substantial monetary benefits to customers.").

BEFORE THE MISSISSIPPI PUBLIC SERVICE COMMISSION

ENTERGY MISSISSIPPI, INC.	IN RE:	NOTICE OF INTENT OF ENTERGY MISSISSIPPI, INC., TO IMPLEMENT A NEW RATE SCHEDULE AND RELATED AGREEMENTS
EC-123-0082-00		
2016-UN-32		

SUBMITTAL OF REPORT ON FEASIBILITY OF COMMUNITY SOLAR

COMES NOW Entergy Mississippi, Inc. ("Entergy Mississippi", "EMI," or the "Company") and hereby submits its Report on the Feasibility of Community Solar in the service territory of Entergy Mississippi ("Community Solar Report") in compliance with the Commission's December 3, 2015, Order in Docket 2011-AD-2 ("Order Adopting Net Metering Rule"), and states as follows:

1. In its Order Adopting Net Metering Rule, the MPSC ordered "all utilities subject to these Rules to file, by July 1, 2016, a report on the feasibility of community solar and other options that may broaden solar choice to a wider group of customers in the utilities' services territories. The report should include the feasibility and potential cost-effectiveness of community solar, including options on how such projects and concepts could be implemented."[1]

2. In compliance with the 2011-AD-2 Order, the Company submits the Community Solar Report attached hereto as Attachment A.

[1] EMI subsequently received an extension until July 15.

WHEREFORE, PREMISES CONSIDERED, Entergy Mississippi hereby requests that the Community Solar Report be received and accepted in compliance with the Order Adopting Net Metering Rule and further prays for any other and general relief as may be necessary, beneficial, or required.

This the 15th day of July, 2016.

ENTERGY MISSISSIPPI, INC.

BY: William H. Hammett

WILLIAM H. HAMMETT
REGULATORY AFFAIRS COORDINATOR

Jeremy C. Vanderloo, MSB No. 101678
Shelly Mott Bass, MSB No. 103857
Entergy Services, Inc.
P.O. Box 1640
Jackson, Mississippi 39215
(601) 969-4838

ATTORNEYS FOR ENTERGY MISSISSIPPI, INC.

STATE OF MISSISSIPPI

COUNTY OF HINDS

Personally appeared before me, the undersigned authority in and for the jurisdiction aforesaid, WILLIAM H. HAMMETT, who after being by me first duly sworn stated that he is Regulatory Affairs Coordinator at Entergy Mississippi, Inc., and that as such is fully authorized to make this affidavit; and further states that the matters and things contained in the foregoing are true, accurate, and correct as therein set forth to the best of his knowledge, information, and belief.

WILLIAM H. HAMMETT
REGULATORY AFFAIRS COORDINATOR
ENTERGY MISSISSIPPI, INC.

SWORN TO AND SUBSCRIBED before me, this the 15th day of July, 2016.

NOTARY PUBLIC

My Commission Expires:

STATE OF MISSISSIPPI
NOTARY PUBLIC
ID # 105745
ANGELA D. REEDER
Commission Expires
June 9, 2017
MADISON COUNTY

RP 6.111 CERTIFICATE OF SERVICE

I, SHELLY MOTT BASS, Attorney for Entergy Mississippi, Inc., hereby certify that on this day I have hand-delivered the original and twelve (12) copies of the above and foregoing document to:

Katherine Collier
Executive Secretary
Mississippi Public Service Commission
2nd Floor
Woolfolk State Office Building
Jackson, Mississippi 39201

and that on this day I have delivered via electronic mail a copy of the above and foregoing document to:

Virden C. Jones
Executive Director
Mississippi Public Utilities Staff
3rd Floor
Woolfolk State Office Building
Jackson, Mississippi 39201

Chad Reynolds
General Counsel
Mississippi Public Utilities Staff
3rd Floor
Woolfolk State Office Building
Jackson, Mississippi 39201

Shawn Shurden
General Counsel
Mississippi Public Service Commission
2nd Floor
Woolfolk State Office Building
Jackson, Mississippi 39201

and that, in the filing of the foregoing, I have complied with Rule 6 of the Commission's Public Utilities Rules of Practice and Procedure.

This 15th day of July, 2016.

Shelly M Bass

SHELLY MOTT BASS
Entergy Services, Inc.
Post Office Box 1640
Jackson, MS 39205-1640

Attachment A

Entergy Mississippi, Inc. Community Solar Report

I. Executive Summary

Entergy Mississippi, Inc. ("EMI") believes that it potentially could develop a community solar project as a feasible option for EMI's customers, including specifically low-income customers. In order for a community solar project to be economically feasible and provide benefits to participants without unduly increasing costs to non-participants, the community solar generating facility (i.e., solar array) needs to benefit from economies of scale associated with larger solar projects. Therefore, it is unlikely for the associated solar project supporting a community solar program to be located in close proximity to neighborhoods or commercial load (e.g., a solar array embedded within or adjacent to the community solar participants). Deployment of community solar in this way may not comport with perceived expectations of size and location (i.e., more centralized generation vs. distributed-scale generation embedded within a community). However, EMI believes this approach is necessary to make community solar viable in Mississippi given the current economics of solar generation and the policy goals to minimize cross-subsidization of community solar participants by non-participants. There are multiple ways to design of a community solar program that are outlined within this report. Within Section V, EMI provides recommendations as to how a community solar program could be structured within Mississippi and plans to discuss these recommendations and other policy considerations with the Commission.

II. Community Solar Overview

For the purpose of this report, the Smart Electric Power Alliance's ("SEPA") definition of community solar is a useful reference point:

> *SEPA considers…community solar a business model with three defining elements: (1) a group of participants voluntarily pay for a share of a solar array that is located external to their properties; (2) the electricity produced flows into the electric grid; and (3) the subscribers receive benefits for the electricity produced by their share of the solar array.*[1]

EMI is using these three elements to define community solar discussed in the report.

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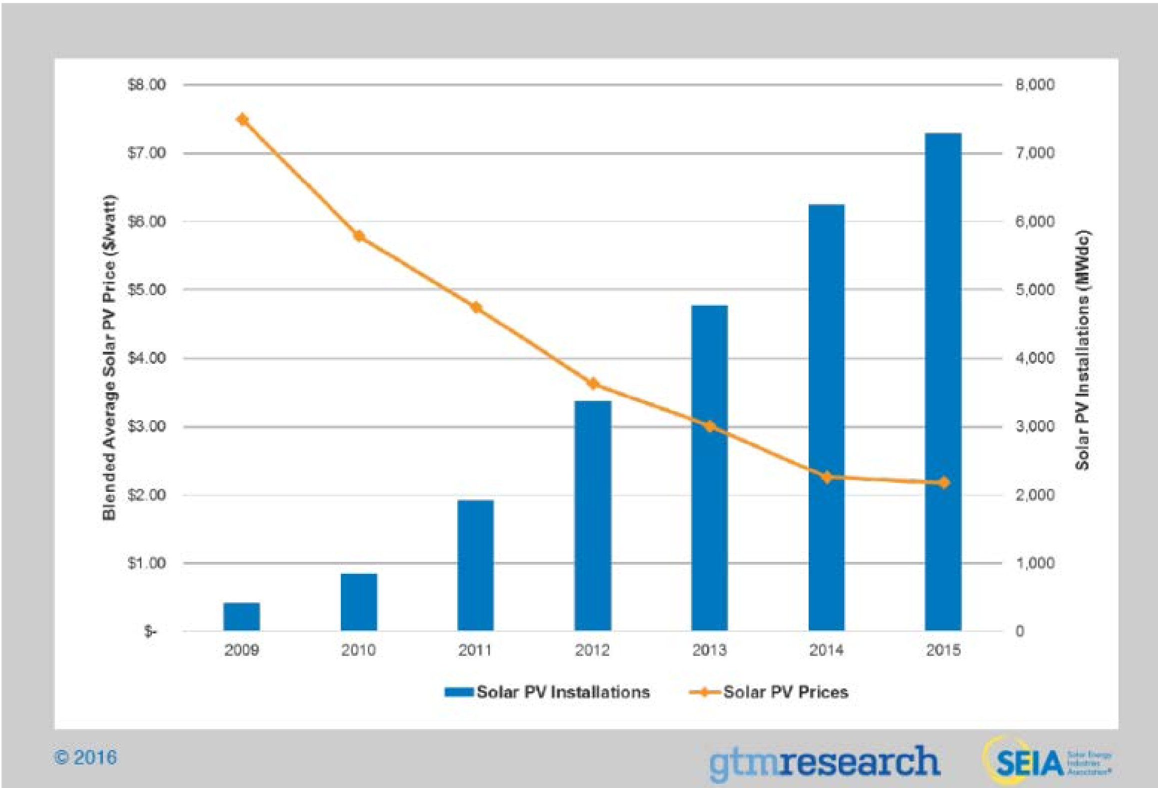
[1] SEPA, *Community Solar: Program Design Models*, November 2015, p. 2; SEPA changed the name of its organization in 2016. At the time this report was published (and since its inception in 1992), SEPA was the Solar Electric Power Association. In April 2016, while maintaining the acronym SEPA, the organization changed its name to the Smart Electric Power Alliance in recognition of the growing connections between solar and other technologies (e.g., demand response, smart grid, energy storage, etc.); last accessed July 14, 2016, report available at: https://sepa.force.com/CPBase__item?id=a12o000000Id07sAAB

Interest and deployment of solar photovoltaic ("PV") technology has increased rapidly in the United States, particularly with the steep decline in installation costs over the last 5-10 years, both at a smaller distributed generation ("DG") -scale and larger utility-scale. As noted in the GTM/SEIA chart below, the blended average cost to install solar PV has fallen significantly since 2009 concurrent with significant growth of installed capacity.[2]



The vast majority of customer-owned rooftops across the U.S. are not suitable for direct installation of a solar PV system due to factors like shading, roof age and condition, rental property where tenants are directly billed for usage, weak customer credit limiting financing and leasing options, and limitations like homeowner's association restrictions. In fact, the Commission noted this issue in the Order:

> *During the October 6, 2015 public hearing, a representative of the Mississippi Chapter of the American Solar Energy Society testified that only forty percent (40%) of Mississippi homes are currently suitable for rooftop solar. That leaves the majority of Mississippi ratepayers, many of whom are low income families, potentially shouldering*

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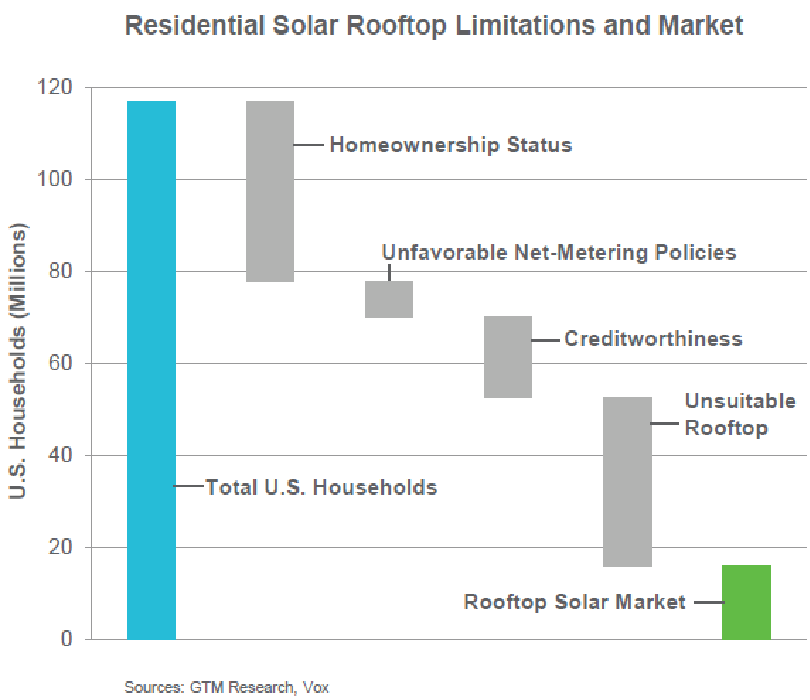
[2] Solar Energy Industry Association ("SEIA") and Greentech Media ("GTM") Research; last accessed July 14, 2016, chart available at: http://www.seia.org/research-resources/solar-industry-data

increased costs. As EMI pointed out in its Supplemental Post-Hearing Comments, by way of example, Congressional District 2, in which most of EMI's customers are located, has the highest poverty rate in Mississippi at 28.2% (nearly double the national poverty rate). The percentage of renter-occupied housing in that district, moreover, is 37.2% (also above the national average), and rental housing is more likely to be occupied by customers who struggle to pay their utility bill and/or fall below the federal poverty level.[3]

Many residential customers across the U.S. that might otherwise be interested in installing a solar PV system on their property are unable to do so as a result of one or more of these limitations. The chart below depicts these limitations.[4]



Interest in community solar programs in the U.S. as an alternative to rooftop solar continues to rise due to: (1) customer demand for more renewable energy options (solar in particular); (2) efforts by utilities to gain more experience with solar and to take advantage of optimizing the location and benefits of solar projects within their service territory; and (3) state policies that foster interest and adoption of community solar concepts.

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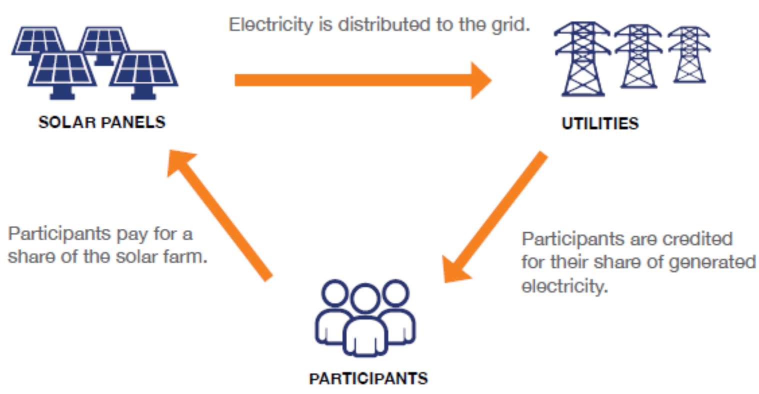
[3] MPSC Order Adopting Net Metering Rule (Docket 2011-AD-2), December 3, 2015, footnote 22 on page 16

[4] GTM/Vox analysis cited within the following Scott Madden report: *Community Solar, Overview of an Emerging Growth Market*, August 2015, p. 1; last accessed July 14, 2016, report available at: http://www.scottmadden.com/insight/community-solar-overview-of-an-emerging-growth-market/

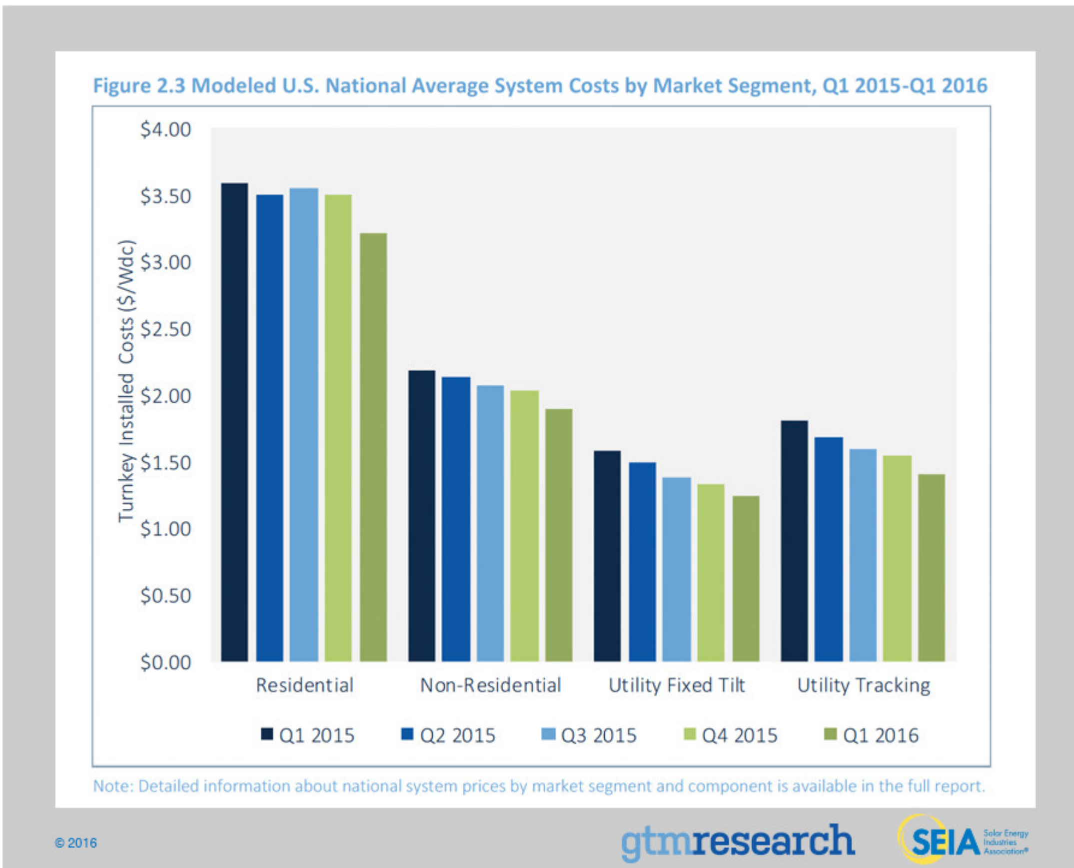
Utility-led community solar programs in Mississippi can provide eligible customers with more opportunity and access to the potential benefits of solar PV. Participants in an EMI community solar program generally could receive several benefits. First, they could obtain economic benefits from solar without actually installing and maintaining solar PV equipment on their property. Second, they could receive additional benefits through sharing in the economies of scale associated with larger, utility-scale solar PV projects. Third, community solar provides a more fungible product to access solar that a participant can continue to benefit from in the event of a move within the utility's service territory. Finally, community solar programs could allow higher recognition of benefits of solar for churches, schools, governmental agencies, and other non-profit entities that may not have the capital to invest and are unable to leverage federal tax benefits associated with solar technology. Sponsoring utilities would also see benefits from community solar programs. For example, these programs provide a way to offer customers an alternative, value-added product, which should be seen favorably by customers and could increase customer satisfaction.

With respect to design, community solar programs generally allow participating customers to subscribe to a certain amount of energy (kWh) or the energy associated with a specific amount of capacity (kW) of a solar project. The associated solar project can either be owned directly by a sponsoring utility or a utility can purchase the energy via a power purchase agreement ("PPA") where the solar project is owned and operated by a 3rd-party. Participants (or sometimes referred to as "subscribers") in the program either make an upfront payment, a series of installment payments, or on-going payments while in the program in order to participate and receive their commensurate share of the community solar project's energy output. In exchange for these payments, subscribers generally receive monetary on-bill credits associated with the value of their pro-rata share of the community solar project. This general model is outlined in the following graphic from a SEPA report:[5]



[5] SEPA, *Community Solar: Program Design Models*, November 2015, p. 3

Community solar programs are able to realize the benefits of deploying a larger, utility-scale solar PV system instead of a smaller residential-sized solar system (typically < 10 kW). These benefits include economies of scale (i.e., lower cost per kilowatt of installed solar PV capacity), improved design and configurations to allow higher solar output and efficiency, and more optimal siting. Lower upfront costs for utility-scale projects are well-documented. For example, GTM and SEIA jointly provide quarterly reports on the U.S. Solar Market that include average pricing for various solar configurations (residential, commercial, utility-scale fixed tilt and utility-scale tracking). The data provided within the most recent such GTM/SEIA report indicates utility-scale pricing is significantly lower than average residential-scale system pricing (see chart below).[6]



In addition to lower system costs, utility-scale projects benefit from other design configurations that can further improve their relative economics and, thus, the overall value to

[6] GTM/SEIA, *U.S. Solar Market Insight - Q2 2016 Report*, p. 13-14; residential rooftop system prices in the quarter are shown to average $3.21/Wdc and utility fixed-tilt and tracking projects in Q1 2016 saw an average pricing of $1.24/Wdc and $1.41/Wdc, respectively; last accessed July 14, 2016, report available at: http://www.seia.org/research-resources/solar-market-insight-report-2016-q2

customers and the power grid. For example, larger, utility-scale projects are typically not as limited by available space. A larger footprint allows these projects to maximize resulting energy production relative to rated inverter capability, and (where appropriate) to cost-effectively deploy single- or double-axis tracking technology.

Several recent studies have assessed the overall economies of scale capturing upfront costs, increased output, and other factors. A 2015 study by the Brattle Group examined the comparative economics of generating power from equal amounts of utility- and residential-scale solar PV resources within Xcel Energy's Colorado service area.[7] The study found that:

> "*…customer generation costs per solar MWh are estimated to be more than twice as high for residential-scale systems, than the equivalent amount of utility-scale PVs. [More specifically, the analysis concluded] projected 2019 utility-scale PV power costs in Colorado range from $66/MWh to $117/MWh across* [the] *scenarios, while residential-scale PV power costs range from $123/MWh to $193/MWh for a typical residential-scale system owned by the customer. For leased residential-scale systems, the costs are between $140/MWh and $237/MWh.*"[8]

Brattle's analysis focused on solar project costs in the State of Colorado, so cost projections may not be representative of solar PV in Mississippi. However, the relative difference in installed costs, operating performance, and economies of scale between an equivalent amount of residential-scale solar PV systems and utility-scale solar PV would be expected in other areas of the U.S. In fact, a recent IHS Energy report considered this likelihood. IHS Energy's projections for 2020 suggests that utility-scale solar PV projects can realize roughly 50% lower energy costs as a result of economies of scale and improved efficiencies, including for solar PV systems located within the Southeastern U.S.[9]

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[7] The Brattle Group, *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area*, July 2015; in the context of this report, community solar projects have the economic structure at the facility level of "utility-scale" projects assessed by Brattle Group study; last accessed July 14, 2016, report available at:
http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado%27s_Service_Area.pdf?1436797265

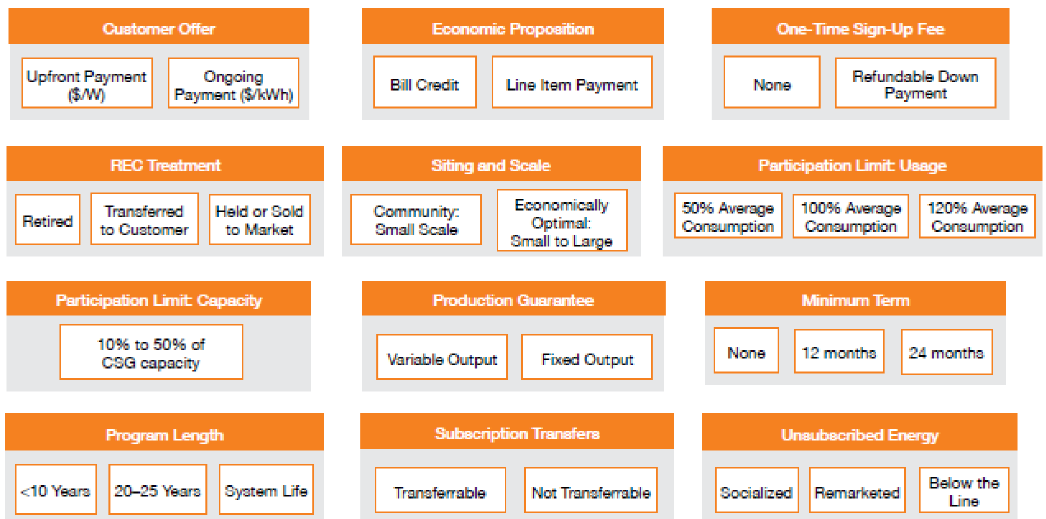
[8] *Ibid*, p. 44

[9] IHS Energy, *Wind and Solar Power Costs, in the Era of Tax Credits and Beyond*, May 24, 2016, p. 15

III. Community Solar Program Design Options

A. Attributes of Program Design

While the type of community solar program contemplated by EMI and discussed in this report must contain three main elements, (see above definition), there also are differences in program design that must be considered. A 2015 SEPA report highlights the key decisions a sponsor of a community solar program must make when designing its program:[10]



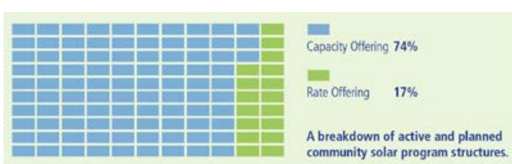
Four of the design choices noted above relate to the costs paid by participants and how benefits are provided to those participants in a community solar program. The *Customer Offer* choice relates to how a participant pays to subscribe to a program, essentially funding that customer's share of the solar facility. Payment can occur via an upfront payment, an on-going payment (which can be expressed in $/month, $/kW-month or $/kWh depending on program design), or a third option not shown above: an upfront payment split into several installments over the first few years of participation. These payments will vary by program and subscription size, but upfront payments required in some programs can be fairly large. The *Economic Proposition* choice (otherwise referred to as the method of crediting program participants with associated benefits) relates to how customers receive value for the energy produced by their share of the solar facility. The *One-time Sign-up Fee* choice captures whether certain administrative and related costs are collected up-front, which serves to guarantee the customer's ability to participate in the program or to provide some incentive for the participant to remain in the program for a minimum term. The final choice relates to how a participant's share of

[10] SEPA, *Community Solar: Program Design Models*, November 2015, p. 11

Renewable Energy Credits ("RECs") is treated.[11] Depending on program design, RECs can be: (1) retired by the program administrator on behalf of customers, (2) transferred to participating customers, or (3) sold to external parties with the resulting value used, for example, to offset some of the costs of the program.

The next few design choices relate to how the program will target potential subscribers. First, the *Siting and Scale* of a project may be a factor in a customer's decision to subscribe and will ultimately affect the economics and benefits to be achieved by the project. For example, some subscribers may be more inclined to participate in a solar PV project that is located within their community in a visible location, which could limit the size of the project and its potential to produce benefits comparable to its costs. Another key factor is the *Participation Limits*, if any, that would serve to cap the level of subscription for different classes of customers and/or any specific customer, thereby ensuring an opportunity for a broader number of customers to participate. These limits typically fall into two categories: usage limits and capacity limits. Usage limits are determined on a per customer basis, and cap a subscription level at some proportion of the customer's expected annual energy usage (*e.g.*, a customer may not subscribe to more than 100% of their historic annual energy usage). Capacity limits typically apply to customer classes to ensure that different classes of customers have the ability to participate in a community solar program (*e.g.*, commercial class may be limited to 40% of the available capacity to ensure that residential customers can participate). Capacity limits also prevent a scenario where a few large commercial or industrial customers secure the entire output of a community solar project, preventing other, smaller customers from enrolling.

The last few choices relate to the inherent flexibility of a program. First, the *Production Guarantee* sets how a participating customer's subscription is determined. Some community solar programs set subscriptions based upon a set amount of kWh produced by the solar project each month, *e.g.*, each subscription equals 250 kWh of solar energy each month. By contrast, most programs set subscriptions based upon a share of the capacity of an overall solar system as shown by the following graphic provided within a 2014 SEPA report:[12]



[11] A renewable energy credit or "REC" is a legal instrument that conveys to its owner the right to claim the associated environmental attributes of a generating resource; one REC is generated for each MWh of renewable power.

[12] SEPA, *Expanding Solar Access Through Utility-Led Community Solar*, September 2014, p. 7; last accessed July 14, 2016, report available at: http://www.solarelectricpower.org/media/214996/community-solar-report-ver5.pdf

In a capacity-based program, the output tied to the subscription will vary by month based upon actual energy output of the associated solar project, and the participating customer will receive value based upon their share of the total monthly energy output from the project. In other words, the customer's share of energy produced each month is tied to the capacity of their subscription as a proportion of the total system capacity. The *Minimum Term* sets the minimum amount of time a subscriber must maintain their enrollment. While there may be some community solar programs that do not have a minimum term, most programs using an ongoing payment structure require a commitment of at least 12 months. *Program Length* can range from less than ten years, 20-25 years or the entire expected life of the solar system. In general, the program length reflects how long a participating customer should expect to receive benefits from their share of the solar project. *Subscription Transfers* (which can also account for subscription portability) refers to whether and how an enrolled customer can pass their subscription to another party or, in the case of portability, continue their subscription in the event of a move within the same utility's service territory. Finally, *Unsubscribed Energy* relates to the accounting treatment of any energy produced by a community solar project that is not subscribed in a particular billing cycle. Most often, given solar PV's zero marginal cost, unsubscribed energy would simply offset energy that the utility would otherwise have purchased or generated itself to serve customer load.

B. Illustrative Programs Previously Deployed in Other States

Below are descriptions of three different utility community solar programs, which are intended to illustrate different design elements. The three utility programs highlighted below are: Consumers Energy (MI), Salt River Project (AZ), and Gulf Power (FL). Several additional utility community solar programs are outlined in a Navigant report prepared in conjunction with the Community Solar Value Project, one of fifteen projects funded in 2015 by the U.S. Department of Energy's SunShot Initiative.[13]

1. Consumers Energy

In 2015, Consumers Energy ("Consumers"), an investor-owned utility with operations in Michigan, obtained approval from the Michigan Public Service Commission ("PSC") to implement a 3-year community solar pilot program for up to 10 MW of solar PV facilities.[14]

[13] *Community Solar Utility Programs*, Andrea Romano – CSVP Team Consultant, Navigant Consulting, November 2015; last accessed July 14, 2016, report available at: http://www.communitysolarvalueproject.com/uploads/2/7/0/3/27034867/20151201_css_case_studies.pdf

[14] Michigan Public Service Commission Case No. U-17752; Consumer Energy's initial application seeking approval of a community solar pilot was filed within the docket in January 2015; conditional approval was issued in May 2015, and the Michigan PSC granted updated, final approval in August 2015 of the updated tariff and bill credit calculation methodology applicable to participating customers.

Under the program, participants subscribe to the output associated with a set portion of capacity from new solar PV resources, and each subscription share, or "SolarBlock," is 0.5 kW of solar PV capacity. The cost to participate depends upon the number of SolarBlocks chosen by the participant, and the payment plan option selected. Customers currently select from four possible payment plan options: (1) a lump-sum, upfront payment of $1,289/SolarBlock, (2) $40 per month per SolarBlock for three years, (3) $20 per month per SolarBlock for seven years, or (4) $10 per month per SolarBlock for 25 years. If a customer selects the first option (a lump-sum, upfront amount), the payment is due from the participating customer upon the start of solar energy production from the associated solar project. The original application requested slightly different payment options: while it included the same upfront, three-year and seven-year payment options, it included a 5-year payment option instead of an ongoing monthly payment spread across the entire expected term of the program (25 years).[15] The filing requesting this change notes, "the addition of a 25-year payment term will reduce the customer's monthly subscription costs, which will further lower enrollment barriers."[16]

Consumers initially required a $100 pre-subscription, sign-up fee to reserve the ability to participate in the program. However, the sign-up fee was reduced to $50 in the first modification to the program in August 2015, and was completely eliminated in a later modification to the program, approved in June 2016, "because Consumers has determined that the pre-subscription payment was a deterrent to customer participation."[17]

Monthly subscription payments are set to recover the anticipated costs and associated revenue requirement of the project, including operations and maintenance ("O&M"), property taxes, depreciation, insurance, debt service, the return on investment associated with the cost of construction, required interconnection and electric system modifications costs, and program management costs. Monthly bill credits (or Solar Energy Credits) received by the subscribers over the 25-year expected life of the solar asset(s) will be provided after the first solar garden is constructed and operating, and are based upon subscription level and the corresponding actual amount of solar energy production per SolarBlock. The value of the monthly Solar Energy Credits is based on the expected value of energy and capacity in the Midcontinent Independent System Operator ("MISO") market (*i.e.*, Consumer's forecasted avoided cost). If the monthly

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[15] Michigan Public Service Commission Case No. U-17752: *Order Approving Tariff*, August 14, 2015; last accessed July 14, 2016, available at: http://efile.mpsc.state.mi.us/efile/docs/17752/0044.pdf

[16] Michigan Public Service Commission Case No. U-17752: *Consumers Energy Company's Application to Amend its Customer Renewable Energy Tariff*, August 7, 2015, p. 3; last accessed July 14, 2016, available at: http://efile.mpsc.state.mi.us/efile/docs/17752/0040.pdf

[17] Michigan Public Service Commission Case No. U-17752: *Opinion and Order*, June 9, 2016, p. 1; last accessed July 14, 2016, available at: http://efile.mpsc.state.mi.us/efile/docs/17752/0052.pdf

Solar Energy Credits are greater than the enrolled customer's monthly bill before application of the credit, any remaining difference will be applied to the enrolled customer's bill for the next month.

Under the current program rules, the Solar Energy Credit rate provides subscribers with a bill credit based on their pro-rata share of energy produced by the solar PV resource multiplied by $0.075/kWh for the first five years after enrollment (as noted above, Consumers' forecasted avoided cost). For years 6-25, the Solar Energy Credit rate will change and will be based upon the value of energy (the MISO market-clearing price, specific to the solar project's locational marginal price ("LMP") on a day-ahead hourly basis) and capacity (updated annually).[18] The calculation of the Solar Energy Credit was a key issue debated in the regulatory proceeding. The original proposal called for the Solar Energy Credit to vary across the entire program based upon a value of solar approach that is now limited specifically to years 6-25. The calculation was later fixed for the first five program years, and the original calculation was retained for years 6 and beyond. The rationale for this change was to provide more "certainty related to [participants'] bill credits in the early years of the program and [to] further customer understanding of the economics of the program. The Company believes that this change will increase customer enrollment."[19]

Consumers has revised the treatment of RECs several times since the program was first proposed. At one point, participants were allowed to choose from two options regarding the treatment of RECs: Consumers could retire RECs annually on their behalf, or subscribers could elect for Consumers to sell RECs, in which case the subscriber would receive an additional credit on their bill for the REC value. In the most recently approved modification to the program, Consumers will no longer offer the second option to new participants. Instead, Consumers will retire all RECs annually on participants' behalf. The Michigan PSC recounts this change in its approving order:

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[18] In the applicable portion of *Consumers Energy Company Rate Book for Electric Service* (Section B, Part II, C10.5): the Solar Energy Credit in Years 6-25 includes two key components: (1) Long Term Program Capacity Value - the product of the Zonal Resource Credits for the facilities, as determined by Mid-Continent Independent System Operator (MISO), and 75% of the applicable MISO published Cost of New Entry for the resource zone in the lower peninsula of Michigan, adjusted annually, and (2) Long Term Program Energy Value - the kWh production of the Solar Program at each hourly interval, multiplied by the hourly day ahead Locational Marginal Price (LMP) at the CONS.CETR pricing node, adjusted for applicable line losses; last accessed July 14, 2016, available at: https://www.consumersenergy.com/uploadedFiles/CEWEB/SHARED/Rates_and_Rules/electric-rate-book.pdf#page=106

[19] Michigan Public Service Commission Case No. U-17752: *Consumers Energy Company's Application to Amend its Customer Renewable Energy Tariff*, August 7, 2015, p. 4

> *"Instead of providing an option whereby the company sells the RECs at the highest available market price on behalf of the participant, Consumers proposes to retire the RECs associated with the Solar Gardens Program. Consumers explains that as the program has developed, the price of RECs has decreased considerably, thus only 5% of customers are electing to have the company sell their RECs. In addition, Consumers contends that retiring RECs on behalf of customers in community solar programs is a best practice, and if a customer sells RECs from the program, the customer is not counted as participating in a renewable energy program. Consumers points to Federal Trade Commission Guides for the Use of Environmental Marketing Claims, which states that: "[i]f a marketer generates renewable electricity but sells renewable energy certificates for all of that electricity, it would be deceptive for the marketer to represent, directly or by implication, that it uses renewable energy." 16 CFR 260.15(d). Accordingly, Consumers contends that because it markets the Solar Gardens Program as one that provides solar energy to customers, the sale of RECs to a third party allows the third party to claim ownership of the environmental attributes of the solar energy, rather than the customer who enrolled in the program. This would be contrary to the intent of the program."*[20]

Consumers' first solar project associated with the program was a 3 MW solar PV project located at Grand Valley State University that started operations in April 2016. A second 1 MW solar PV project located at Western Michigan University is under construction and is expected to be operational by July 2016. Based on a quarterly report filed with the Michigan PSC in May 2016, 497 customers have enrolled in the program so far representing ~55% of the 4 MW (or ~8,000 SolarBlocks) of subscriptions available for the first two announced projects.[21] Consumers started pre-enrolling customers in the fourth quarter of 2015. With the first project operational in April, pre-enrolled customers would have started making subscription payments in June 2016.

There are additional rules for the program involving eligibility. In general, the program is available upon request to customers taking service under certain rate schedules and who have not received a shut-off notice in the previous nine months. Enrollment is also on a first-come, first-served basis. In the event the program is oversubscribed, participants' names will be maintained on a Consumers' list in the order in which they were received, and the participants will be enrolled on a first-come, first-served basis if the program is expanded. Finally, customers that relocate outside of Consumers' service territory may elect to receive an equitable pro-rated refund of any upfront subscription amount if they provide appropriate notice per program rules.

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[20] Michigan Public Service Commission Case No. U-17752: *Opinion and Order*, June 9, 2016, pages 1-2.

[21] Michigan Public Service Commission Case No. U-17752: *Consumers Energy Company's Solar Gardens Report*, May 9, 2016, p. 1; last accessed July 14, 2016, available at: http://efile.mpsc.state.mi.us/efile/docs/17752/0051.pdf

As noted above, the first two solar projects built through the program are just coming online, and, according to Consumers' latest quarterly report, enrolled customers will incur their first subscription payments in June 2016. With limited history on the program thus far, it is difficult to make definitive conclusions regarding the program. However, EMI notes several of the changes Consumers made to the design of the program since its original application was filed in January 2015 that could better inform how a community solar program might work in Mississippi. For example, EMI will continue to monitor the effect on Consumers' program of the addition of an on-going monthly payment option for the Subscription Payment that is spread across the entire program length, since this could be a more affordable choice that would allow the program to be feasible for more customers. In addition, EMI is interested in the effect on the program of two other recent program revisions with respect to sign-up fees and the treatment of RECs as to whether eliminating sign-up fees and retiring RECs on behalf of customers are a more effective choice for those attributes of program design that would improve enrollment rates.

2. Salt River Project

In 2011, Salt River Project ("SRP"), a quasi-state-owned utility in Arizona that currently serves about one million customers in the Greater Phoenix area launched a community solar program for its customers. Under the program, customers purchase the output associated with 1-kW increments of capacity from the associated project. With respect to their share of the project, participants were limited by the customer's total kWh consumption in the prior 12 billing periods or an estimation if historical usage data was not available. As a result, the amount of energy associated with the customers' subscription varies from one month to the next given the inherent intermittent nature of a solar project.

The SRP program is similar to the Consumers Energy program described above from the perspective of a participant being entitled to the energy (kWh) output from a set amount of capacity. However, the monetary contributions from participants and benefits enrolled customers receive are quite different under the SRP program. Instead of providing customers with a credit in exchange for upfront and/or on-going participation fees, participants in the SRP program were able to lock in a fixed rate for solar energy that lasts five to ten years.[22] SRP sources energy for the program via a long-term PPA with Iberdrola from the 20 MW Copper Crossing solar PV project located in Florence, AZ.

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[22] Residential customers were limited a 5-year price lock through the program. Eligible business and school accounts were able to obtain price lock for up to 10 years through the program. The program was frozen with respect to new enrollment as of the April 2015 billing cycle; *SRP Standard Electric Price Plans*, Community Solar Pilot Riders, p. 139-148; last accessed July 14, 2016, available at: https://www.srpnet.com/prices/priceprocess/pdfx/TempJuly2016RatebookPUBLISHED.pdf

After rolling out the program, SRP found initial participation to be low and less than the company might have expected, especially among their commercial customers. SRP ultimately modified the program design in 2014 by reducing the fixed rates in an attempt to increase program participation.[23] At the time the lower rates were announced in December 2013, only about 12 MW (or 60% of the solar project) was subscribed, including about 100 schools (interested in the 10-year price lock offered to those customers) and 1,170 residential customers (limited to a 5-year price lock). Since the reduced rates were announced, the number of enrolled residential customers has increased to over 2,800. When combining residential, school, and commercial subscriptions, enrollments have increased to approximately 15 MW (or 75% of the solar project).[24] The community solar program was frozen to new subscribers as of the April 2015 billing month. SRP later explained the freeze was to allow "the program [to be] redesigned to be more in line with [its] new rates for solar rooftop customers."[25]

The experience and history of SRP's program provides several insights for future community solar programs, including ones in Mississippi. Overall, SRP has struggled with enrolling customers, and has still not fully subscribed the program. The program itself was fairly large (20 MW) for a new concept that had yet been tested in a pilot.

A second factor that appears to have affected the subscription levels is the economic value proposition to participating customers. As noted above, upon the initial deployment of the program, SRP offered participants a fixed energy rate ($/kWh) that they would pay for their share of the output of the project that was set at a premium to the customer's standard retail rates. However, once a customer was charged a community solar rate that provided a slight discount to SRP's average retail rates (at least in the case of residential customers), enrollment levels in their program significantly increased. The table below outlines the difference in the economic value proposition for customers based on the 2011 rate at the start of the program versus the revised rate starting in 2014.

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[23] Randy Randazzo (reporter for The Arizona Republic), *SRP Community Solar Prices Cut*, April 22, 2014; last accessed July 14, 2016, available at: http://www.azcentral.com/story/money/business/2014/04/22/srp-community-solar-prices-cut/8015135/;

[24] Randy Randazzo (reporter for The Arizona Republic), *SRP Breaks Ground on New Florence Solar Facility*, July 19, 2015; last accessed July 14, 2016, available at: http://www.azcentral.com/story/money/business/2015/07/19/new-srp-solar-plant-florence-arizona/30333829/

[25] *Ibid*.

	Residential customers	**Business customers**
Initial community solar rates offered in September 2011	$0.1125/kWh	$0.099/kWh
Average rate paid by SRP customer class in 2011[26]	$0.1072/kWh	$0.082/kWh
Premium or (discount) to average rates offered by program at the time of the 2011 launch	*$0.0053/kWh or 4.9% premium*	*$0.017/kWh or 20.7% premium*
Revised community solar rates offered when program was revised in May 2014	$0.099/kWh	$0.089/kWh
Average rate paid by SRP customer class in 2014[27]	$0.1132/kWh	$0.083/kWh
Premium or (discount) to average rates offered by program after 2014 modifications	*($0.0142/kWh) or 12.5% discount*	*$0.006/kWh or 7.2% premium*

It is important to note that SRP was one of the first utilities in the U.S. to offer a community solar program. The underlying solar project supporting their program (Copper Crossing) was built at a time when installed solar costs were much higher, as presumably was the PPA price between SRP and the project's owner, Iberdrola. New solar projects built to support community solar programs will benefit from the significant cost reductions in solar technology that have been realized in the last few years.

A final observation regarding the results of SRP's program is that it has resulted in a large amount of unsubscribed energy. The solar energy associated from the program comes from the long-term PPA between SRP and Iberdrola. The original rates set in 2011 would presumably have covered the cost of the PPA and administrative costs for the program. However, once the fixed rates were reduced in 2014 to foster greater participation, the revenue associated with the community solar program would presumably have no longer covered the full costs of the PPA and program administration costs. As a result, SRP is likely recovering any shortfall related to the reduced rates and unsubscribed energy from non-participants, which would only be a concern if the underlying solar resource did not provide overall net economic benefits.

3. Gulf Power

Gulf Power obtained approval for their Energy Share program in March 2016 from the Florida PSC.[28] The program is available to all customer classes, and has two components: (1) an

[26] EIA Form-826 data for 2011; business customers calculated based on an average of all non-residential customers; last accessed July 14, 2016, available at: https://www.eia.gov/electricity/data/eia826/xls/f8262011.xls

[27] EIA Form-826 data for 2014; business customers calculated based on an average of all non-residential customers; last accessed July 14, 2016, available at: https://www.eia.gov/electricity/data/eia826/xls/f8262014.xls

[28] See Florida PSC Docket 150248-EG; last accessed July 14, 2016, available at: http://www.psc.state.fl.us/ClerkOffice/DocketFiling?docket=150248

annual subscription fee, which reflects the projected annualized revenue requirement of the program; and (2) a monthly bill credit participants receive for their share of the energy produced by the solar PV facility. Each subscription is sized at ~750 kWh per year and Gulf Power expects to sell ~2,880 subscriptions for the first 1 MW solar PV project that they are planning to construct. Customers are able to sign up for more than one subscription, but per-customer subscriptions will be capped such that total subscriptions will not exceed 100 percent of the customer's average kWh consumption for the previous 12-month period. Customers that do not commit to at least a 5-year term pay $99 per year to participate, and are automatically re-enrolled for the following year unless they provide a 30-day notice to Gulf Power to cancel their subscription. Customers that agree to participate in the program for at least five years pay $89 per year.

All enrolled customers receive a monthly bill credit that corresponds to the amount of their subscription. Monthly bill credits will be determined each calendar year and will be based upon a solar-weighted average annual avoided energy credit. The credit rate is set using the projected hourly output of the program's solar facilities, Gulf Power's projected hourly avoided energy costs, and the number of subscriptions needed to fully subscribe the program. At the time the program was filed for approval, Gulf Power estimated the credit would amount to approximately $2.00-2.50 per month per subscription in the first year ($24-30/year or approximately 3.2 – 4.0 cents/kWh assuming 750 kWh of energy per share). Gulf Power's bill credit calculation only captures avoided costs associated with the wholesale value of energy. It does not include any credit for the avoided cost of capacity or other benefits that may exist. By contrast, other community solar programs, such as the Consumers Energy example outlined above, do include capacity value within the overall avoided cost calculation used to determine bill credit rates.

Gulf Power will own and operate the solar asset(s) used to supply the program, and the first facility is a 1 MW project to be built on existing property owned by Gulf Power near Milton, FL. Additional solar facilities may be constructed if the first facility is fully subscribed.

Gulf Power's program is designed such that all costs are borne solely by program participants. Gulf Power states in their application that the bill credits are not intended, or expected, to fully offset the annual subscription fees paid by participating customers. Prior to their enrollment, participants will be informed by Gulf Power that they will be paying a premium for the foreseeable future to participate. The projected annual revenue requirements used to set the annual subscription fees include all costs associated with engineering, procurement, construction, operation, and maintenance of the solar facilities, as well as program and marketing costs. In setting the annual subscription fees, Gulf Power notes that they plan to levelize the projected annual revenue requirements over a 35-year expected asset life assuming a zero net salvage value at the end of that period. The RECs associated with the program will be retired by Gulf Power on behalf of participants.

To determine interest, Gulf Power retained a market research firm to conduct nine customer focus groups and telephone surveys on solar in general and community solar programs more specifically. As reported by Gulf Power, the results indicated that a majority of residential and small business customers are supportive of solar initiatives and that at least some are willing to pay a premium for solar. According to Gulf Power's research, the average annual premium customers surveyed were willing to pay was $346 for residential customers and $414 for business customers.[29] Of customers expressing interest in community solar, Gulf Power's research indicated that 2% of residential customers and 1% of small business customers would "definitely" be willing to pay more for solar. Consistent with the expected 35-year asset life, the Staff of the Florida PSC recommended and the Florida PSC approved a 2.9% annual depreciation rate for solar PV projects constructed as part of this program. The initial 1 MW project is not expected to be complete until late 2016 or early 2017, and therefore subscriptions have not started yet.

Since the initial solar project that will be built to supply the program is still under construction and participation has not yet begun, it is too early to draw any conclusions about the effectiveness of this program design in Gulf Power's service territory.

IV. Community Solar Review Undertaken by EMI

In preparation for filing this report, EMI conducted research and analysis on community solar developments across the country. EMI's team, composed of representatives from regulatory and resource planning, among others, together with subject matter experts from Entergy Services, Inc., reviewed a variety of publications and regulatory filings related to community solar programs to better understand the range of program design structures deployed to-date. Documents reviewed by EMI's team include analysis from SEPA, GTM, SEIA, Rocky Mountain Institute ("RMI"), the U.S. Department of Energy ("DOE"), the National Renewable Energy Laboratory ("NREL"), ScottMadden, and IHS Energy. EMI's team also reviewed specific community solar programs offered or proposed by several utilities. EMI used information from reviewing these documents to develop the recommendations provided in Section V of this report.

EMI also sought the direct assistance of a party that could provide subject-matter expertise and advisory support in determining the feasibility of a potential community solar program for Mississippi. EMI is working with Clean Energy Collective ("CEC"), a leading developer of community solar solutions in the U.S. CEC helped develop the community solar

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[29] *Petition for Approval of Gulf Power's Community Solar Pilot Program*, November 19, 2015, filed in Florida PSC Docket No. 150249-EG, p. 10; last accessed July 14, 2016, available at: http://www.psc.state.fl.us/library/filings/15/07372-15/07372-15.pdf

model in 2009-2010 and also established the earliest community-owned solar array in the country in 2010 near El Jebel, Colorado. Since that time, CEC has built or has under development more than 100 community solar projects with 27 utility partners across 12 states, serving thousands of customers, and representing more than 160 MW of community solar capacity. EMI has worked with CEC to further develop and refine the recommendations provided below.

V. EMI's Recommendations Regarding Community Solar Program Design–

As a result of EMI's research and input provided by CEC, EMI recommends the following program design parameters for a community solar program that could be developed and offered to EMI customers:

1. **Program Structure**: an on-going (or "pay-as-you-go") program would likely appeal to more of EMI's customers than a program that would require a large upfront payment from participants. According to SEPA, "73% [of active community solar programs] have an upfront payment customer offer, 17% have an ongoing payment, and 10% allow customer choice among the two options."[30] However, an upfront payment structure could require significant upfront investment from a participant. In the Consumers Energy program described in Section III.B.1., a residential customer that chooses the upfront payment option for a 5 kW subscription level would owe the utility $12,890 upon the later of enrollment or commercial operation of the associated solar project. Requiring such a significant upfront investment likely would preclude many EMI customers from participating in a community solar garden program. By contrast, a pay-as-you-go model should be more inclusive, would allow low-income and less affluent customers to more easily participate, and ultimately should provide for more interest by EMI's customers in a community solar project. On-going fees also can be structured in a way that does not penalize customers who move in and/or out of EMI's service area and who can no longer participate in the program.

2. **Method of Compensation for Program Participants**: a monetary bill credit approach (rather than volumetric energy credit) should be used for a community solar program in Mississippi to credit participants for the value of energy associated with their subscription. A monetary bill credit approach would also be consistent with the Commission's Net Metering Order, which provides a bill credit for exported energy based upon a set value for the "Total Benefits of Distributed Generation." In addition, monetary bill credits would mitigate the cost-shifting concerns acknowledged in the Commission's net metering order while ensuring that non-participants do not bear

[30] SEPA, *Community Solar: Program Design Models*, November 2015, p. 11; these percentages are based on number of programs and are not weighted by MW or other factors.

increased costs as a result of a community solar program. Bill credits also would be simpler to describe to interested participants and also less complicated for billing purposes.

3. **Sign-up Fee**: no sign-up fee should be required for subscribers, although a commitment to participate in the program for a set period of time (*e.g.*, at least 12 months) should be required to mitigate customer service cost. As noted in section III.A, sign-up fees are often used to provide some assurance for the utility sponsoring a program in case participants attempt to drop out before the end of the minimum term. However, EMI is suggesting a pay-as-you-go model and believes that sign-up fees can serve as a deterrent for enrollment, and therefore EMI recommends against charging such a fee.

4. **Renewable Energy Credit ("REC") Treatment**: to ensure that the program is able to be marketed publicly as a way for customers to obtain solar (i.e., renewable) energy in compliance with U.S. Federal Trade Commission ("FTC") regulations, EMI should retire RECs on behalf of participating customers (rather than transferring RECs to participants or selling RECs via a broker or exchange).[31] The recommended approach would allow EMI to retain greater flexibility to ensure customers understand that the community solar program is a "renewable" option, and also is consistent with one of the lessons learned from Consumers Energy's program.

5. **Customer Eligibility**: all customer classes should be eligible to participate in a community solar program.[32] In addition, all participating customers must be in good standing from a billing and collections perspective prior to enrolling in the program and also while being a participant. EMI prefers to be as inclusive as possible in structuring the program design such that most customers should be eligible to participate. EMI discusses low-income participation separately below.

6. **Production Guarantee**: each participating customer should be able to subscribe to the output associated with a specified amount of capacity, and will receive a monthly bill credit in proportion to the customer's share of the actual energy generated by the specified amount of capacity (as a percentage of the overall output of the solar facility). This approach, rather than one in which customers subscribe to a pre-determined amount of energy (kWh blocks) assumed to be generated by the community solar facility, ensures

[31] Section 5 of the FTC Act, 15 U.S.C. 45 and U.S. Code of Federal Regulations: Title 16, Chapter I, Subchapter B, Section 260.15

[32] Certain rate schedules and riders may be excluded from participating in a community solar program (e.g., lighting).

participating customers receive a proportional credit for the actual energy produced by the solar project each month consistent with the effects of varying weather patterns and maintenance. In addition, this approach provides enrolled customers with an understanding of the variability of solar production, and an experience that is more consistent with that of a customer with installed, onsite solar generation (*i.e.*, a net metering customer). This approach also should prevent non-participants from paying higher costs as a result of a community solar program.

7. **Participation Limits**: each customer's participation should be limited in accordance with the following requirements, in order to ensure adequate opportunity for interested customers to participate:
    a. A participating customer's subscription cannot be sized above 100% of the customer's average annual energy usage based on the most recent 12 months of usage. The 100% threshold is a common limit for community solar programs, and some utilities even restrict participation below 100% of usage to expand availability.
    b. Participating customers must subscribe to output of at least 2 kW from an associated solar project. This threshold will reduce the administrative burden of managing a large volume of small subscriptions, although it could be waived, if appropriate, for qualifying low income customers.
    c. A single customer cannot subscribe to more than a set percentage (*e.g.*, 10%) of the available capacity from an associated solar project. In addition, a set percentage of available capacity (*e.g.*, 50%) should be preserved for residential customers. It may be appropriate to also further limit the size of customer subscriptions in order to expand access. Applying these types of thresholds and limits will allow more customers to participate in the program.
    d. A portion of the program should also be dedicated to low income customers, as explained further below.

8. **Program Length**: the length of the program should be defined in advance in order to allow customers to fully understand upfront the value proposition of their participation. EMI has observed that many community solar programs are 20 years in length, although other timeframes could be considered.

9. **Low Income Participation**: EMI wants to ensure that low income customers have ample opportunity to participate in a program, consistent with the Commission's policy directives. In order to educate and inform this segment of EMI's customers on a community solar offering, EMI can use its existing relationships and communication channels with community-based organizations in the area, much like it does with its Energy Efficiency Quick Start Programs, as well as other methods of communication directed specifically to low-income customers. A significant proportion of the program (at least 10-15%) should be specifically reserved for low income customers, and outreach

efforts related to the program should target this group of customers. In addition, EMI recommends that low income-qualified customers should receive an additional benefit from participating in the program: namely a higher bill credit rate applied to the monthly share of energy output from their subscription. This added benefit would be similar to the additional credit provided to net metered low income customers in the Order.

10. **Minimum Participation Period**: EMI recommends that any customer signing up for a community solar program be required to stay enrolled in the program for at least 12 months to help mitigate sign-up and customer service costs. Although the program design recommended above does not call for a sign-up fee or upfront payment, a minimum participation period of 12 months serves to reduce administrative complexity and cost, as well as minimize the potential for individuals to game the system by jumping into and out of the program to take advantage of the seasonal variation in solar output. Having a 12-month minimum period also reduces turnover and administrative costs related to subscribing new customers for the program when participants cancel their subscription. Exceptions to this requirement (without penalty) could be provided for enrolled customers that move to a location outside of EMI's service territory less than 12 months after starting their subscription, and therefore must close their EMI account. Any other enrolled customers that want to terminate participation less than 12 months after enrolling should face a monetary consequence, such as continued requirement to pay the monthly enrollment fee.

11. **Subscription Portability and Transferability**: subscriptions should be portable and connected to an enrolled customer's EMI account. In other words, customers should be able to continue their subscription in the event that they move within EMI's service territory. As noted by SEPA: "allowing for portability provides value to the customer," and they recommend all community solar programs allow this option.[33] By contrast, if an enrolled customer moves to a location outside of EMI's service territory, the customer will leave the program and should be allowed to do so without penalty (even if they are enrolled for less than the 12 months minimum participation period). If a customer leaves EMI's service area, it wouldn't be possible for EMI's community solar facility to continue to provide value to that customer. However, EMI does not recommend that enrolled customers be provided the ability to transfer their subscription to another EMI customer. Transfer provisions in other community solar program are typically associated with programs involving upfront payments. Under that type of model, customers pay for subscription in advance in order to receive the bill credits (or other benefits) throughout the program, and a transfer option would allow a subscriber to designate future program

[33] SEPA, *Community Solar: Program Design Models*, November 2015, p. 14

benefits to another party, should they choose to do so. Since EMI has recommended an on-going payment approach, the ability to transfer subscriptions does not seem applicable or necessary.

12. **Unsubscribed Energy**: in the event that the program is not fully subscribed for a particular billing cycle, the unsubscribed energy will be used to serve load to offset energy from other EMI generating sources or market purchases.

13. **Minimum Bill**: consistent with the Commission's Order, participating customers should not be able to reduce their bill below the "minimum bill" threshold applied to net metering customers (fixed charges plus applicable riders). If, as a result of an approved community solar program, any on-bill credits associated with participation in the community solar program are unable to be fully applied in a given billing cycle, the unused credit would carry over to the next billing cycle in a manner described by EMI's Net Energy Metering Rider Schedule NEM-1 ("Schedule NEM-1").

14. **Methodology to Calculate Customer On-going Payments & Bill Credits**: many different approaches and methodologies have been used to set the customer payment and bill credit rates for community solar programs. Given EMI's review of the various options that might be used for a pay-as-you-go approach, the Company recommends the following.
    a. The bill credit rate ($/kWh unit) should be determined for the first year, and could be based upon an avoided cost calculation or an alternate approach such as how excess energy credit rates are determined in the Commission's net metering Order. If approved by the Commission, a higher bill credit rate could be similarly established for qualifying low income customers.
    b. EMI should use the expected output for the community solar program subscriptions, the low income program cap, and the pre-set bill credit rates to calculate the total expected bill credit payments due to participants.
    c. In order to provide a value proposition to program participants, the customer subscription rate should be set (in $/kW-month terms tied to the participant's desired capacity) such that the total revenue EMI would receive from subscribers provides a modest amount of bill savings (*e.g.*, perhaps 5% on an annual basis) for customers that do not qualify as low income. The participants that do qualify for the low income subscriptions would make on-going payments at the same rate as other customers. However, their benefit in the form of overall savings associated with program participation would be higher because their bill credits would be higher.
    d. EMI should determine whether and how the customer payments and bill credit rates should change from one program year to the next. It would provide more

certainty for participants to fully understand their commitments in the program prior to or at the time they enroll. To provide this type of certainty, EMI would need to set a fixed schedule for customer payment rates, and any associated increases in those rates, at the start of the program. By contrast, bill credit rates may not need to be fixed in advance for the entire program length. Many utilities have designed programs allowing the bill credit rate to fluctuate over time according to underlying factors like the value of avoided energy and capacity. In this scenario, the program provides a set methodology to calculate a bill credit rate, often on an annual basis and using a formula tied, for example, to the utility's avoided costs.

e. Regardless of how bill credit rates are set, the utility and potential participants should consider that solar technology does experience degradation over time. As a result, the energy output associated with each participant's subscription should be expected to modestly decrease over time. The community solar program should be structured in such a way as to preserve the value proposition to enrolled customers such that they would continue to receive modest savings on an annual basis over the entire program.

15. **Mitigating Impacts to Non-participants**: EMI is fully aware there is a net cost associated with a methodology for setting bill credits and customer payment rates in which participants receive more benefit than they pay into the program over the program's life. Under an ideal community solar program design, the sum of (1) the annual net cost from customer payments and bill credits, (2) the revenue requirements associated with the solar project investment, O&M, and other costs (net of any normalized tax benefits), (3) the various avoided energy, capacity, and environmental costs associated with solar project output and capacity, and (4) the revenue requirements associated with the upfront and operating costs to administer the community solar program would collectively provide a net benefit to all of EMI's customers on a net present value basis. If achieved, this ideal economic picture would help mitigate cross-subsidization from non-participants and avoid higher costs being paid by non-participants, as from an overall perspective all customers would see a net benefit for the solar project and community solar program investment. If necessary, a utility could develop a community solar program that is sized smaller than the new solar project associated with it in order to ensure that the overall investment provides a net benefit to all customers.

16. **Associated Solar Project**: For all of the reasons explained herein, EMI believes that the scale of EMI's three existing 500 kW solar pilot projects does not make them a preferred option for a community solar program. However, it should be noted that those pilot projects had a specific purpose, namely to learn more about solar and to test different

sites and configurations (fixed tilt versus single-axis tracking). In order to link a new community solar program to actual investment and to capture larger economies of scale, EMI recommends consideration of a larger solar project on Company-owned property. To achieve economies of scale for customers, EMI recommends that a new solar project at least 5 to 10 MW in capacity be constructed to support the program. If appropriate in order to test the concept, a community solar program could be initially associated with only a portion of a larger solar project, and expanded in the future based upon customer interest.

17. **Role of EMI Program Development**: EMI expects that it would be responsible for the development, construction, financing, and ownership of the associated community solar project. EMI would also be responsible for developing and administering the community solar program. As with any utility function that EMI provides, EMI management would evaluate whether or not community solar program administration could be performed more cost-effectively by a third party than by internal staffing. As noted above, EMI has retained CEC to assist with this filing and is considering utilizing their services to ultimately administer and/or support a community solar program.

VI. Conclusion

EMI believes that community solar could be a practical option for its customers. However, the myriad of program design features requires feedback from the Commission. EMI intends to discuss the report and its recommendations with the Mississippi Public Utilities Staff and the Commission staff. With Commission input, EMI plans to develop a community solar program that could be offered to its customers as an alternative for customers who cannot or choose not to install rooftop solar on their property.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO	**)**	**DOCKET NO. UD-18-07**
COUNCIL RESOLUTIONS R-15-194	**)**	
AND R-17-504 AND FOR RELATED	**)**	
RELIEF	**)**	

REBUTTAL TESTIMONY

OF

DR. AHMAD FARUQUI

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ahmad Faruqui. I am a Principal at the Brattle Group, an economics consulting firm. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q2. DID YOU FILE REVISED DIRECT TESTIMONY IN THIS PROCEEDING IN SEPTEMBER 2018?

A. Yes. I previously submitted Revised Direct Testimony on behalf of Entergy New Orleans, LLC ("ENO" or the "Company") before the Council of the City of New Orleans (the "Council").

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to some of the arguments in the direct testimonies of Ms. Pamela G. Morgan (Alliance for Affordable Energy or "AAE"), Mr. Justin R. Barnes (AAE), and Mr. Victor Prep (Advisors).

Q4. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. Section II of my Rebuttal Testimony responds to criticism regarding ENO's proposed Demand-Side Management Cost Recovery ("DSMCR") Rider and confirms the need and the relevance for the cost recovery and performance incentive mechanisms proposed. Section III of my testimony addresses issues related to ENO's proposed increase in the residential fixed charge and responds to AAE's and Advisors' comments on ENO's proposal. I also describe how ENO's proposal is in line with widely recognized rate design principles and industry standards.

II. DEMAND-SIDE MANAGEMENT COST RECOVERY RIDER

A. Lost Contribution to Fixed Costs ("LCFC") Mechanism

Q5. PLEASE SUMMARIZE YOUR OPINION OF ENO'S PROPOSED DSMCR.

A. As stated in my Revised Direct Testimony, Demand-Side Management ("DSM") is a clean and cost-effective resource that both ENO and the Council have deemed a priority.[1] The Council has expressed strong support for ENO's Energy Smart efforts, and has also established a goal of achieving aggressive incremental energy savings targets through Energy Smart.[2] In furtherance of this goal, ENO's proposed DSMCR Rider fully aligns the interests of ENO and its customers in order to maximize the savings produced from ENO's DSM offerings. Specifically, the DSMCR Rider will put in place the three elements required to achieve parity between the financial treatment of investing in DSM and supply-side resources while ensuring DSM measures are creating savings for customers: (1) timely recovery of utility DSM program costs, (2) recovery of fixed costs attributable to lost kWh sales from DSM, and (3) a performance incentive tied to savings achievements. Effectively combining these three elements provides the necessary framework for utilities to invest in DSM, as is seen with successful DSM programs in jurisdictions across the U.S.

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[1] Revised Direct Testimony of Ahmad Faruqui at 4.

[2] Council Resolution R-15-599, December 10, 2015, pp. 3, 17.

Q6. AAE WITNESS MORGAN'S TESTIMONY STATES THAT "AN LCFC IS NOT NECESSARY TO LEVEL THE PLAYING FIELD BETWEEN DEMAND-SIDE AND SUPPLY-SIDE RESOURCES" (MORGAN 33). DO YOU AGREE?

A. No. Ms. Morgan argues that DSM investments do not deserve equal treatment because DSM investments carry less risk, *e.g.*, the risk of incorrect planning and premature obsolescence utilities may face when investing in supply-side assets.[3] Accordingly, she asserts that it is not necessary for the playing field to be completely "leveled."

Q7. DO YOU AGREE WITH AAE WITNESS MORGAN'S CLAIM?

A. No, I disagree. The prudence and adequacy of utility investments (including supply-side and DSM) are determined as of the time the investments are made. Premature obsolescence occurs when conditions in which the investment was originally made have changed significantly. DSM investments could similarly become obsolete, leading to the utility having to repurchase or re-invest in programs financially supporting the purchase of equipment. For example, a common utility energy efficiency measure consists of incentives for customers to purchase more efficient lighting for their homes. Certain lighting products could become obsolete if more advanced and efficient technologies are invented a few years later (*e.g.*, faster turn-on and ability to be dimmed). In fact, this very situation occurred with the recent transition from compact fluorescent ("CFL") lightbulbs to new Light Emitting Diode ("LED") lightbulbs. Given the benefits of LED lighting, customers may replace CFLs before the end of their useful life, and ENO may

3 Direct Testimony of Pamela G. Morgan at 34.

find it beneficial to launch another effort to support the purchase of these new and better LED lightbulbs.

Q8. MS. MORGAN ALSO ALLEGES THAT CONTRARY TO YOUR REVISED DIRECT TESTIMONY, "NATIONAL DSM AND ENVIRONMENTAL GROUPS DO NOT SUPPORT MECHANISMS SUCH AS THE LCFC" (MORGAN 35). WHAT IS YOUR RESPONSE?

A. As stated in my Revised Direct Testimony, national DSM and environmental advocacy groups fully support that utilities should be allowed to recover fixed costs that are lost when sales fall because of successful DSM programs.[4] Mechanisms that allow such recovery include lost revenue adjustment mechanisms (typically called "LRAMs") similar to ENO's proposed LCFC mechanism and "decoupling." In particular, both the American Council for an Energy-Efficient Economy ("ACEEE") and the Natural Resources Defense Council ("NRDC") mention LRAMs as options to mitigate the "throughput incentive," under which volumetric rates can create an incentive for utilities to increase electricity sales (and under which DSM programs might discourage utilities from decreasing their sales if the utilities cannot recover the lost fixed costs).[5]

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4 Revised Direct Testimony of Dr. Ahmad Faruqui at 19.

5 NRDC, "Removing Disincentives to Utility Energy Efficiency Efforts," p. 4, accessed at https://www.nrdc.org/sites/default/files/decoupling-utility-energy.pdf; ACEEE, "Aligning Utility Business Models with Energy Efficiency," accessed at https://aceee.org/sector/state-policy/toolkit/aligning-utility.

Q9. DOES MS. MORGAN PROVIDE ANY EVIDENCE OF NATIONAL DSM AND ENVIRONMENTAL GROUPS OPPOSING MECHANISMS SUCH AS LCFC?

A. No. First, Ms. Morgan references several reports from NRDC and ACEEE, all of which:

- Identify the need to remove the inherent discouragement of utilities not recovering their fixed costs because of the potential decrease in sales related to DSM investments,[6]
- Cite LRAMs as an option for removing such disincentives,[7] and
- Note how the use of LRAMs is widespread in the U.S. [8]

Second, Ms. Morgan attempts to prove her point by highlighting that these reports put forward decoupling as a preferable solution to LRAMs. I disagree with her perspective, as such "preference" would not substantiate her claim that "national DSM and environmental groups do not support mechanisms such as the LCFC."[9] In addition, Ms. Morgan agreed in her deposition that, if decoupling is not approved in this proceeding, some form of LRAM (with certain requirements) would be appropriate to address revenue erosion caused by Energy Smart implementation.[10] And Company witness D. Andrew Owens explains in his Rebuttal Testimony that the Council's Resolution R-16-103, upon which the Company's proposed "decoupling" mechanism is

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6 NRDC, "Removing Disincentives to Utility Energy Efficiency Efforts," pp. 1-2.

7 NRDC, "Removing Disincentives to Utility Energy Efficiency Efforts," p. 4; ACEEE, "Aligning Utility Business Models with Energy Efficiency," accessed at https://aceee.org/sector/state-policy/toolkit/aligning-utility.

8 *Ibid.*

9 Direct Testimony of Pamela G. Morgan at 35.

10 Morgan deposition at 62-63 (March 14, 2019).

based, does not adequately address lost revenues resulting from Energy Smart, thus requiring the LCFC mechanism included in the proposed DSMCR Rider.

Third, AAE witness Morgan claims that I am "conflating lost revenue recovery through a mechanism with decoupling and incentives for fulfilling energy efficiency goals."[11] In answer to this claim, I need to clarify my Revised Direct Testimony. In my Revised Direct Testimony, I defined the term "LCFC" as the "Lost Contribution to Fixed Cost" which occurs when a utility's DSM portfolio reduces energy sales below a forecasted amount, and thus causes the utility to under-recover fixed costs.[12] As a result, I used "LCFC recovery" to refer more generally to recovery of those lost fixed costs, be it through an LRAM or decoupling. However, given that "LCFC" may be interpreted as referring to ENO's specific proposal, I would now amend my use of "LCFC recovery" to "recovery of fixed costs."[13] And as I explain above, recovery of fixed costs is fully supported by national DSM and environmental policy groups.[14]

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11 Direct Testimony of Pamela G. Morgan at 35.

12 Revised Direct Testimony of Dr. Ahmad Faruqui at 5.

13 For instance, Q20 of my Revised Direct Testimony asks "Do national DSM and environmental policy groups support LCFC recovery and performance incentives as important aspects of a robust DSM initiative?" I would now amend this question to "Do national DSM and environmental policy groups support recovery of fixed costs and performance incentives as important aspects of a robust DSM initiative?"

14 On page 12 of my Revised Direct Testimony I note that "[r]ecovery of DSM-specific LCFC is most commonly achieved concurrently through a dedicated DSM rider based on a forward-looking period." AAE witness Morgan interprets this as a claim that an LRAM is the most common approach to addressing sales lost to utility DSM efforts (Morgan Direct at 37). However, I was simply describing the most common form that an LRAM takes in recovering DSM-specific LCFC, which is the forward-looking approach.

B. Rate-Basing DSM Investments

Q10. WHAT IS AAE WITNESS BARNES'S CRITIQUE WITH REGARD TO YOUR SUPPORT FOR RATE-BASING DSM INVESTMENTS?

A. AAE witness Barnes believes that the four examples described in my Revised Direct Testimony of other jurisdictions which have approved rate-basing of DSM investments are not enough to indicate a trend. AAE witness Barnes argues that given that rate-basing is still relatively uncommon, rate-basing of DSM expenses is more "a trend in something that utilities want, but that has yet to reach a strong position as a best practice."[15] He also individually criticizes the examples of the Utah and Illinois bills as being written specifically for the benefit of Rocky Mountain Power and ComEd respectively. Lastly, AAE witness Barnes more fundamentally disagrees with rate-basing DSM on the basis that it overcompensates the utility by "distort[ing] the playing field… rather than leveling it."[16]

Q11. WHAT IS YOUR ANSWER TO THESE CRITICISMS?

A. While I do not care to quibble with Mr. Barnes about the necessary criteria for establishing a trend, the point I am making in my Revised Direct Testimony is that DSM rate-basing is gaining acceptance for its attributes.

A recent ACEEE report on DSM performance incentives, issued after I filed my Revised Direct Testimony, mentions the "recent adoption" of DSM rate-basing as a "notable development" which "[levels] the playing field for demand-side investments"

[15] Direct Testimony of Justin R. Barnes at 39-40.

[16] Direct Testimony of Justin R. Barnes at 40-41.

and "spread[s] the bill impacts of efficiency across a longer period, ensuring that customers pay for efficiency measures while they are benefitting from them."[17] Moreover, in addition to the examples I gave in my Revised Direct Testimony, rate-basing of DSM investments is also allowed in New Jersey. In 2015, the New Jersey Board of Public Utilities (BPU) authorized PSE&G to amortize its DSM investments over a 7-year period, and to earn a return for the amortization of the regulatory asset at the utility's weighted average cost of capital ("WACC").[18]

Mr. Barnes also criticizes the relevance of the Utah and Illinois bills. He asserts that the Utah bill received "significant criticism from many parties," but the criticisms he describes largely focus on the regulatory process and on provisions other than the inclusion of rate-basing, none of which are relevant in evaluating ENO's proposal.[19] He emphasizes that Rocky Mountain Power largely influenced the bill, but I understand that before the bill was approved it underwent a complex legislative process with multiple amendments which concluded by passing the bill.[20] Moreover, Rocky Mountain Power's subsequent application for approval of its DSM programs and rider was part of a regulatory proceeding with multiple interveners and testimony.[21] AAE witness Barnes also provides little basis for dismissing Illinois' Senate Bill ("SB") 1585. His only

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[17] ACEEE, "Snapshot of Energy Efficiency Performance Incentives for Electric Utilities," December 2018, p. https://aceee.org/sites/default/files/pims-121118.pdf

[18] *See* Order Adopting Stipulation, NJ BPU Docket No. EO14080897, April 15, 2015. IT capital enhancements were instead amortized over a 5-year period.

[19] Salt Lake Tribune, "Critics say Rocky Mountain Power Plan would stick it to Utah ratepayers in the name of clean air," February 9, 2016, referenced in Direct Testimony of Justin R. Barnes at 40.

[20] See Utah State Legislature, "S.B. 115 Sustainable Transportation and Energy Plan Act," accessed May 30, 2018, https://le.utah.gov/~2016/bills/static/SB0115.html.

[21] See Utah PSC Docket No. 16-035-36.

reference to substantiate his point is an article published months before the bill's passage, which mostly focuses its criticism of SB 1585 on a proposed demand charge that ComEd supported. However, when the bill ultimately passed after negotiations that were considered "an impressive example of collaboration" by the involved clean energy, environmental, consumer, and community groups, it had been modified to reflect multiple compromises and did not include a demand charge.[22]

Furthermore, New York and Maryland, the two other examples of jurisdictions which have approved rate-basing of DSM investments, described in my Revised Direct Testimony, both rank in the top 10 states of ACEEE's *2018 State Energy Efficiency Scorecard*.[23] Maryland's EmPOWER programs for DSM are in particular considered a success with wide-ranging benefits for the state,[24] while its cost recovery mechanism for DSM is considered one of the most successful in the country.[25]

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[22] Energy News Network, "Illinois energy bill: After race to the finish, what does it all mean?", December 8, 2016, accessed at https://energynews.us/2016/12/08/midwest/illinois-energy-bill-after-race-to-the-finish-what-does-it-all-mean/.

[23] ACEEE, "2018 State Scorecard," October 2018, p. xii, accessed at https://aceee.org/research-report/u1808.

[24] ACEEE, "Maryland Benefits: Examining the Results of EmPOWER Maryland through 2015," January 2017, accessed at https://aceee.org/sites/default/files/publications/researchreports/u1701.pdf.

[25] CLEAResult, "Creating Customer and Investor Value through Energy Efficiency," July 11, 2017, accessed March 8, 2019 at https://www.clearesult.com/insights/whitepapers/creating-customer-and-investor-value-through-energy-efficiency/.

Q12. WHAT IS THE DISTORTION DESCRIBED BY AAE WITNESS BARNES?

A. AAE witness Barnes argues that rate-basing DSM investments creates a distortion because "energy efficiency expenditures produce both foregone energy expenses in addition to foregone capital investments."[26]

Q13. DO YOU AGREE WITH AAE WITNESS BARNES'S CLAIM?

A. I do not. While I agree that energy efficiency expenditures will reduce energy consumption and thus fuel and purchased power expenses, this cost reduction is typically passed through to the customers as part of the fuel adjustment clause and therefore does not increase in any way earnings that may come from a return on DSM investments. Moreover, similar to DSM investments, some supply-side investments may reduce fuel expenses. For example, investing in a more efficient generation asset could decrease ENO's average fuel purchases, but would not prevent in any way this supply-side investment from earning a return on equity.

Q14. WHAT IS ADVISOR WITNESS PREP'S CRITICISM OF RATE-BASING DSM INVESTMENTS?

A. Advisor witness Prep claims that "regulatory asset treatment is more appropriate if a large non-recurring cost is recovered over several future years," implying that DSM investments do not fall into the category of "large non-recurring assets."[27] I agree that, historically speaking, under traditional cost-of-service ratemaking, DSM expenses would

[26] Direct Testimony of Justin R. Barnes at 40-41.

[27] Direct Testimony of Victor Prep at 69.

not typically be recovered as a regulatory asset. DSM costs would traditionally be expensed in the year incurred. But as explained in my Revised Direct Testimony, the traditional regulatory paradigm can act as a road block to encouraging aggressive and effective DSM.[28] In order to maximize the potential for achieving the Council's aggressive DSM goals and to incorporate DSM as a core component of ENO's business, ENO is proposing a progressive solution that would allow for rate-basing of expenses that are traditionally not rate-based. This solution benefits both customers and the Company. A good example of a similar progressive solution with regard to encouraging innovation is in the information technology area of regulated utility services, the rate-basing of cloud computing expenses described by Mr. Owens in his Rebuttal Testimony.

C. DSM Performance Incentives

Q15. WHY DOES AAE WITNESS BARNES CLAIM THAT A PERFORMANCE INCENTIVE THAT PROVIDES REWARDS FOR ALL POTENTIAL PROGRAM OUTCOMES "IS SIMPLY A COST THAT SERVES NO BENEFICIAL PURPOSE?"[29]

A. AAE witness Barnes agrees that performance incentives should be considered to encourage support for DSM,[30] but suggests that the presence of an energy efficiency resource standard ("EERS") is a stronger indicator of energy savings and spending among U.S. jurisdictions than the existence of a performance incentive. As a result, he suggests that "the stick is sometimes more effective than the carrot," and that the point of

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[28] Revised Direct Testimony of Dr. Ahmad Faruqui at 11-12. *See also* AAE Exhibit PGM-3, Direct Testimony of Pamela G. Morgan, pp. 1-2.

[29] Direct Testimony of Justin R. Barnes at 48.

[30] Direct Testimony of Justin R. Barnes at 47.

an incentive is that "the incremental cost is a reasonable tradeoff for the contribution it makes to the success of the program."[31]

Q16. DO YOU AGREE WITH THIS CONCLUSION?

A. No. I disagree that the effectiveness of the EERS demonstrates the effectiveness of the "stick" (*i.e.*, penalties for utilities) over the "carrot" (*i.e.*, fair compensation for utilities). AAE witness Barnes derives his findings from an ACEEE report that analyzed spending and savings for 2013. However, ACEEE issued a survey of EERS as of January 2014 which found that while 26 states had adopted and fully funded EERS policies, only five states include a penalty in the EERS mechanism and eighteen include a performance incentive (with reward only). The report concludes that "[o]nly a few states have opted to use the stick approach by assigning a penalty for not meeting targets," and that instead "[m]ost states use the carrot approach, offering utilities and non-utility program administrators a rate of return or financial reward if they meet or exceed their targets."[32] In other words, evidently, the savings achieved by states with an EERS are not attributable to penalty mechanisms, and do not disprove the encouraging results of performance incentives.

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[31] Direct Testimony of Justin R. Barnes at 48.

[32] ACEEE, "Energy Efficiency Resource Standards: A New Progress Report on State Experience," April 2014, pp. 18-20, accessed at https://aceee.org/research-report/u1403.

Q17. DO YOU AGREE WITH AAE WITNESS BARNES THAT ENO'S PROPOSED PERFORMANCE INCENTIVE IS "TOO RICH"?[33]

A. No. AAE witness Barnes argues that ENO's incentive is "too rich" because it provides for a non-zero return on equity regardless of savings level, and includes too steep of a step function for rewards.[34] I disagree with this allegation because ENO's 100 basis point reduction for savings less than 60% does provide a penalty in that if it earns less than the allowed rate of return while recovering DSM expenditures over several years, DSM will be penalized in comparison to supply-side investments. Therefore, ENO would be recovering its DSM investments over several years, while earning less than the allowed rate of return, which strikes me as being a penalty, for reasons that Mr. Owens describes more fully in his Rebuttal Testimony.

In addition, utilities' DSM performance incentives are often designed with no explicit penalty for falling short of their target. In his Direct Testimony, AAE witness Barnes references five states (Massachusetts, Rhode Island, California, Vermont, and Connecticut) which rank highest on ACEEE's 2018 Energy Efficiency Scorecard.[35] Among these states, all five offer a performance incentive, none of which includes a penalty mechanism.

33 Direct Testimony of Justin R. Barnes at 48.

34 Direct Testimony of Justin R. Barnes at 48.

35 ACEEE, "The 2018 State Efficiency Scorecard," October 2018, accessed at https://aceee.org/sites/default/files/publications/researchreports/u1808.pdf, referenced in Direct Testimony of Justin R. Barnes at 19.

Lastly, the accountability and "adverse consequences for unreasonably poor performance" that Mr. Barnes requests may be achieved outside of the incentive itself.[36] The Council must first approve all of ENO's DSM programs, savings goals, and budgets as part of the IRP process, which then informs ENO's specific DSM investments.[37] In the case of underperformance, the Council retains the authority to disallow DSM investments deemed imprudent, which as described in the Rebuttal Testimony of Andrew Owens, may serve as an implicit penalty mechanism.

Q18. HOW DOES THE LEVEL OF ENO'S PROPOSAL COMPARE TO OTHER UTILITIES' PERFORMANCE INCENTIVES?

A. ENO's proposal is generally in line with the level of incentive authorized in other states. Through the proposed ROE adjustment, it could earn a performance incentive of up to 200 basis points, equivalent to approximately 10% (in net present value) of its estimated program costs for 2020.[38] To benchmark that amount, I reviewed the allowed performance incentive amounts relative to DSM program costs in states considered successful at energy efficiency policy. This sample was based on the top fifteen states with the highest "utility and public benefits programs and policies" scores on ACEEE's 2018 State Scorecard.[39] One surveyed utility, ComEd, is allowed a maximum incentive of up to 200 basis points as 125% of its savings goals, equivalent to ENO's proposal. To

36 Direct Testimony of Justin R. Barnes at 52.

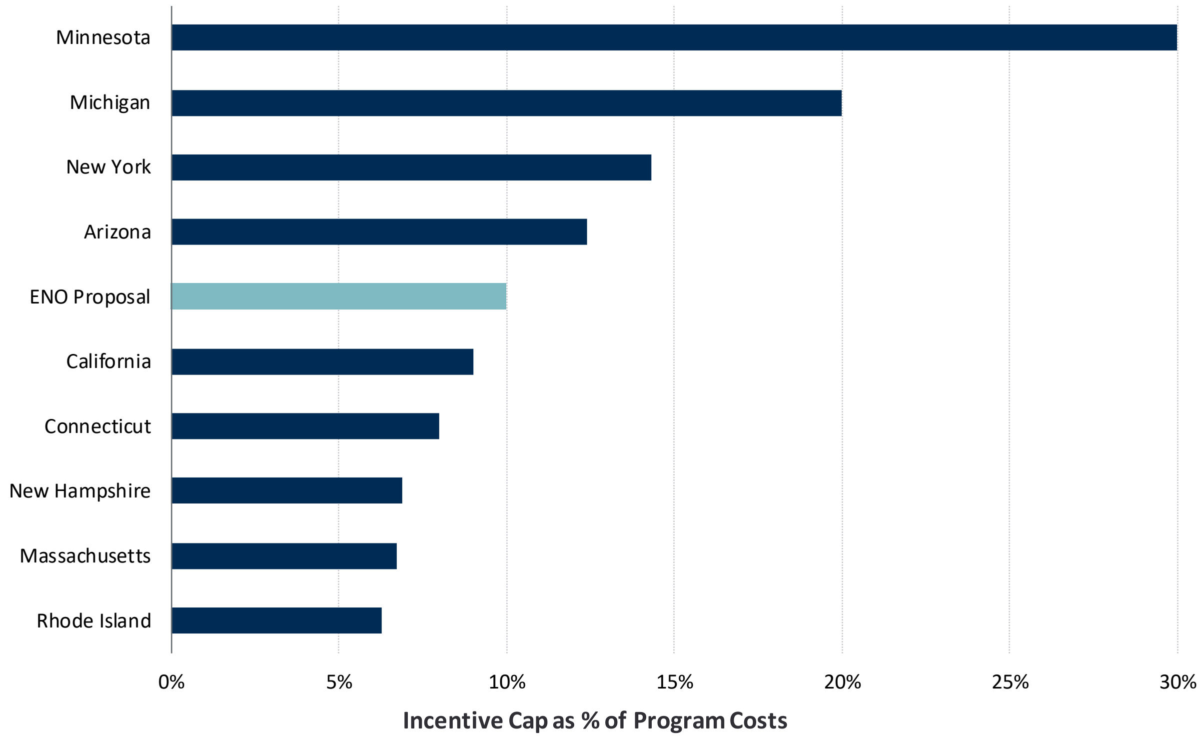
37 Revised Direct Testimony of D. Andrew Owens at 19, 21.

38 Assumes program costs of approximately $14 million recovered over four years.

39 The utility score measures a state's "performance in implementing utility-sector efficiency programs and enabling policies that are evidence of a commitment to energy efficiency." See ACEEE, "2018 State Scorecard," pp. 19-23.

benchmark ENO’s proposal against the incentives allowed in other states, which may be defined as either a share of program costs, a share of net benefits, or a preset amount, I computed each maximum allowed performance incentive as a share of DSM program costs in the most recent program year for which data was readily available. Among the nine states where utilities have the opportunity to earn a performance incentive, the average incentive cap as a percentage of program costs was approximately 13% and the median was 9%, as shown in Figure 1. While this benchmark does not account for any differences in policy (such as the aggressiveness of DSM savings goals) or cost recovery between states, it does provide a useful comparison and supports that ENO’s proposed implied maximum compensation of 10% of program costs for Program Year 10 is in line with that of other U.S. utilities and not “too rich.”

Figure 1: Performance Incentive Caps as % of Program Costs



Notes: Sample derived from the top 15 states based on utility score according to ACEEE's "2018 State Scorecard," pared down to reflect states where utilities have the opportunity to earn a performance incentive and excluding Illinois. Illinois' performance adjustment for ComEd is a maximum of 200 basis points.

Q19. DO AAE WITNESSES MORGAN'S AND BARNES'S RECOMMENDATIONS CHANGE YOUR PERSPECTIVE ON ENO'S PROPOSED DSMCR RIDER?

A. No. My perspective remains that ENO's proposed DSMCR Rider is in line with both industry practice and the Council's goals. By allowing (1) full recovery of prudent DSM program costs, (2) mitigation of under-recovered fixed costs, and (3) a performance incentive tied to savings achievement, it addresses all three challenges inherent to utility investment in DSM. As a result, it will level the playing field between DSM and supply-side investments and support ENO in achieving its savings targets.

III. FIXED CHARGE INCREASE

A. ENO's Proposal Is in Line with Rate Design Principles

Q20. WHAT MAJOR RATE DESIGN PRINCIPLES SHOULD BE USED TO EVALUATE ENO'S PROPOSAL FOR SETTING THE RESIDENTIAL FIXED CHARGE?

A. Since its initial publication in 1961, Professor James C. Bonbright's canon, *Principles of Public Utility Rates*,[40] has served as a guide for designing rates and is one of the most quoted references in public utility ratemaking. In the first edition of his text, Bonbright propounded eight principles which were expanded into ten principles in the second edition. These are almost universally cited in rate proceedings throughout the U.S. and are often used as a foundation for designing rates. For ease of exposition, these principles can be grouped into five key criteria: economic efficiency, equity, bill stability, customer satisfaction, and revenue adequacy and stability. I discuss below the applicability of the Bonbright principles to the establishment of a customer charge. As discussed in the Revised Direct Testimony of Joshua B. Thomas[41] and in the Rebuttal Testimony of Myra L. Talkington, the customer charge is designed to recover those costs incurred by the utility in serving customers that do not vary with the amount of energy consumed by the customer or with the demand imposed on the grid by the customer. They pertain to the cost of metering, billing, and customer care.

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[40] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition.

[41] Revised Direct Testimony of Joshua B. Thomas at 61-62.

Q21. WHAT IS THE PRINCIPLE OF EQUITY?

A. There should be no unintentional subsidies between customers within a rate class (or between rate classes). Thus, if the cost-based customer charge is $X, but the actual customer charge is half of that amount, then the balance of the fixed cost has to be recovered through the volumetric charge. The magnitude of that recovery would be set correctly for the average usage customer. But for the smaller than average usage customer, a portion of the fixed cost will not be recovered, since that customer has less than average usage (volume). And for the larger than average usage customer, more than the correct amount of the fixed costs will be recovered, since that customer has higher than average usage. In other words, larger-than-average usage customers will subsidize lower-than-average usage customers.

Q22. WHAT IS THE PRINCIPLE OF BILL STABILITY?

A. Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh's in Year 1, and the number of kWh's halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

Q23. WHAT IS THE PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?

A. Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

Q24. IS THERE AN OVERRIDING PRINCIPLE THAT SHOULD GUIDE RATE DESIGN DECISIONS?

A. Yes. The overriding principle in rate design is that of cost causation. In other words, the rate structure should reflect the underlying cost structure. The importance of economic efficiency – and specifically on designing rates that reflect costs – is emphasized by Bonbright. In the first edition of his text, Bonbright devotes an entire chapter to cost causation. In the chapter, he states: "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred."[42] Later, he states "The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty."[43] Bonbright also cites another benefit of the cost-price standard, saying that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to 'account' for this draft by the surrender of a cost-

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[42] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.

[43] Op. cit., p. 69.

equivalent opportunity to use his cash income for the purchase of other things."[44] Of course, the pursuit of this principle has to be informed by the notion of gradualism.

Q25. HOW DO YOU EVALUATE ENO'S PROPOSAL TO RAISE THE FIXED CHARGE AGAINST THE MAJOR RATE DESIGN PRINCIPLES?

A. As explained above, to the extent that the customer charge is moved closer to the fixed cost of serving the customer, to that extent the rate design will move closer to conformity with the Bonbright principles.

Q26. WHAT ARE AAE WITNESS BARNES'S CRITICISMS WITH REGARD TO ENO'S POLICY JUSTIFICATIONS FOR ITS PROPOSAL?

A. Mr. Barnes argues that rates should not be designed using an embedded cost of service basis. His rationale seems to be that only marginal cost-based rates will promote economic efficiency and encourage efficient energy consumption. That viewpoint is not found in Professor Bonbright's widely used text. Nor is that viewpoint to be found in the rates that are offered by most utilities in the U.S., which use embedded costs to design rates. Many of these utilities encourage energy efficiency through the provision of financial incentives to consumers at the time they are purchasing new appliances, light bulbs, or other energy-consuming equipment.

[44] Op. cit., p. 70.

B. ENO's Proposal Is in Line with Other Utilities' Practices

Q27. DO YOU AGREE WITH WITNESS BARNES THAT ENO'S PROPOSAL IS EXTREME BECAUSE IT WOULD LEAD TO A FIXED CHARGE "FAR IN EXCESS" OF OTHER U.S. UTILITIES?[45]

A. ENO's proposal is a step toward recovering the full fixed cost of serving customers and is guided by the principle of cost-causation. A benchmark of fixed charges being collected by other utilities' current rates is a poor guide to the development of ENO's fixed charges. More and more utilities are requesting increases in their fixed charges to move them closer to recovering the associated fixed costs. A snapshot of the national landscape cannot be used to guide ENO's fixed charges. For instance, 34 utilities in 22 states filed requests in 2018 to increase their residential fixed charges by at least 10%.[46] In comparing ENO's proposal to a national average, as well as the average for ENO affiliates and companies deemed "comparable" to ENO for the use of calculating its cost of capital (which for obvious reasons should not be considered relevant when analyzing rate design), AAE witness Barnes also ignores significant variation in fixed charges among utilities analyzed, including numerous utilities with fixed charges exceeding ENO's proposal.[47]

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45 Direct Testimony of Justin R. Barnes at 10-12.

46 NC Clean Energy Technology Center, "50 States of Solar: Q4 2018 Quarterly Report & 2018 Annual Review," January 2019.

47 Direct Testimony of Justin R. Barnes at 12.

C. Response to Advisors' and AAE's Concerns on the Proposed Fixed Charge Increase

Q28. HOW DO YOU RESPOND TO WITNESS BARNES'S CLAIM THAT A RATE DESIGN WEIGHTED TOWARD FIXED CHARGES DISCOURAGES CUSTOMERS FROM PURSUING ENERGY EFFICIENCY?[48]

A. I disagree that increasing the fixed charge will inherently discourage customers from adopting energy efficiency measures. Studies indicate that customers respond to their total bill, rather than individual elements in their bill.[49] In other words, they consider their average price over their marginal (or volumetric) price and are rarely influenced by how large is the fixed portion of their bill. As a result, increasingly weighting a rate design towards fixed charges will result in low demand elasticity and have little impact on average price or customer incentives to conserve electricity. Furthermore, customers are incentivized to respond positively to DSM efforts through other financial tools. For example, utility DSM investments commonly promote energy efficiency by offering customers rebates for high-efficiency consumer appliances like clothes dryers and refrigerators among other types of measures.[50]

As evidence that states which prioritize energy efficiency recognize the negative impacts of fixed charges, AAE witness Barnes calculates that the top five states ranked according to ACEEE's 2018 Energy Efficiency Scorecard have a low average residential

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48 Direct Testimony of Justin R. Barnes at 17-19.

49 Koichiro Ito, "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing," *American Economic Review* 104(2) (February 2014): 537-63, https://www.aeaweb.org/articles?id=10.1257/aer.104.2.537.

50 In an ACEEE survey of 51 utilities, 20 offered programs promoting the purchase of high-efficiency consumer electronics and 14 offered rebates for high-efficiency residential clothes dryers. *See* ACEEE, "2017 Utility EE Scorecard," June 2017, p. 94, accessed at https://aceee.org/sites/default/files/publications/researchreports/u1707.pdf.

fixed charge of $6.05/month.[51] This average is skewed downwards by California, whose three largest investor-owned utilities (PG&E, SCE, and SDG&E) currently have fixed charges between $0 and $0.93/month. I also note that all three utilities have pending requests for fixed charge increases between $7.40 to $10/month.[52] In addition, the state that ranks sixth in the scorecard, New York, has an average fixed charge of $18.13/month based on the data provided in Mr. Barnes's workpapers.[53]

Q29. DO YOU AGREE WITH WITNESS BARNES THAT ENO'S PROPOSED FIXED CHARGES WOULD HAVE A DISPROPORTIONATE IMPACT ON LOW-INCOME CUSTOMERS?[54]

A. No, I do not agree with him. My review of ENO's data on customer incomes and electricity usage suggests that about 40% of low-income customers are high-use customers who would see a decrease in their bill with the new fixed charge since the volumetric charge would be lower.[55] I should note that the distribution of usage for low-income customers is similar to the distribution of usage for the population of all residential customers. For the portion of low-income customers who do see an increase in their monthly bill, they would have access to several options, including some funded

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51 Direct Testimony of Justin R. Barnes at 19.

52 NC Clean Energy Technology Center, "50 States of Solar: Q4 2018 Quarterly Report & 2018 Annual Review," January 2019, pp. 103-105.

53 "AAE 1-1_Fixed Charge Comparisons_Table 1&2_WP.XLS," provided in response to ENO's first set of requests for information and included with my workpapers WP AF-2.

54 Direct Testimony of Justin R. Barnes at 25.

55 *See* the HSPM attachment to ENO's Response to AAE 2-5, Docket No. UD-18-07 (included with my workpapers WP AF-2). I consider low-income customers to be those with incomes below $50,000, and high-use customers to be those with usage above 1,000 kWh.

by ENO, which help provide bill protection. For instance, ENO offers a Power to Care program to help protect elderly and disabled customers on low or fixed incomes. Through the program, ENO shareholders match donations from customers and employees to fund emergency bill payment assistance for customers struggling to pay their utility bills.[56] ENO's Energy Smart efforts also include a Low-Income program to specifically support energy savings among low-income customers. The program offers qualifying customers a variety of free energy efficiency measures, including direct install measures like the installation of high efficiency LED bulbs and water saving fixtures, as well as smart thermostats, central AC tune-ups, attic or ceiling insulation and weatherization.[57]

Lastly, residential customers will also be able to take advantage of level billing, which smooths out their billing into roughly equal monthly amounts, or pre-pay, which allows them to pay for energy services in advance.[58] Both options allow customers greater control over their budget and planning, and may mitigate the frequency and impact of bill surprises.

Q30. WHAT DO YOU CONCLUDE REGARDING ENO'S PROPOSAL TO INCREASE ITS FIXED CHARGE?

A. I conclude that ENO's proposed increase in its fixed charge is in line with rate design principles since it would bring the new fixed charge to be better aligned with ENO's costs, improve bill stability for the customer, and improve revenue stability for ENO.

[56] Entergy, "The Power to Care," http://www.entergy.com/our_community/power_to_Care_Video.aspx

[57] *See* https://www.energysmartnola.info/residents/.

[58] *See* http://entergy-neworleans.com/features/level_billing.aspx (level billing) and the Revised Direct Testimony of Raiford L. Smith at 4-24 (pre-pay).

ENO's proposal to raise its fixed charge is also in line with that of other utilities' practices in the U.S. Many utilities have been requesting increases in their fixed charges in recent years and many utilities have already received approval.

IV. CONCLUSION

Q31. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF California

COUNTY/PARISH OF Contra Costa

NOW BEFORE ME, the undersigned authority, personally came and appeared,

AHMAD FARUQUI,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

AHMAD FARUQUI

Sworn to and

Subscribed Before Me

This 15th Day of March, 2019.

NOTARY PUBLIC

BADAL DHOLARIA
COMM. # 2214676
NOTARY PUBLIC • CALIFORNIA
CONTRA COSTA COUNTY
Comm. Expires SEPT. 17, 2021

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

MICHELLE P. BOURG

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

PUBLIC VERSION

MARCH 2019

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Michelle P. Bourg. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113. I am employed by Entergy Services, LLC ("ESL")[1] as the Vice President, Transmission Operations. Until March 10, 2019, I served as the Director of Gas Distribution. In this capacity, I was responsible for overseeing all aspects of the safe, reliable delivery of natural gas service to Entergy New Orleans, LLC's and Entergy Louisiana, LLC's natural gas customers. My specific responsibilities included, but were not limited to, safety, compliance with applicable pipeline safety regulations, operations, customer service, construction, maintenance, engineering, planning, and gas real-time system monitoring and dispatch for the Company's gas distribution system.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony before the Council of the City of New Orleans ("the Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. ARE YOU THE SAME MICHELLE P. BOURG WHO FILED REVISED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

[1] ESL is an affiliate of the five Entergy Operating Companies ("EOCs") and provides administrative and support services to the EOCs. The five EOCs are Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to Direct Testimony filed by the Advisors regarding (i) the Company's proposed Gas Infrastructure Replacement Program ("GIRP") Rider, and, (ii) what have been historically referred to as "Non-Jurisdictional" gas customers. Specifically, my Rebuttal Testimony responds to:

1. the recommendations set forth in the Direct Testimony of Advisors' witnesses Joseph W. Rogers, Byron S. Watson, and of Crescent City Power Users' Group witness Richard A. Baudino regarding the Company's proposed GIRP Rider and the need for certainty regarding the pace of replacement of aging gas infrastructure and a mechanism for recovery for the duration of the program; and
2. the recommendations set forth in Advisors' witness Victor Prep's Direct Testimony regarding the treatment of costs and revenues related to Non-Jurisdictional gas customers on ENO's system.

III. GIRP RIDER

Q5. THE ADVISORS' DIRECT TESTIMONY MAKES A NUMBER OF RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED GIRP RIDER AND ASSOCIATED COSTS, INCLUDING THE RECOMMENDATION THAT THE COUNCIL DENY THE RIDER ON THE GROUNDS THAT IT IS INAPPROPRIATE

SINGLE-ISSUE RATEMAKING. DOES THE COMPANY AGREE WITH THIS ASSESSMENT?

A. Company witness Mr. Joshua B. Thomas responds to the Advisors' ratemaking issues in connection with the Company's request to implement a GIRP Rider. My Rebuttal Testimony addresses the technical aspects of the GIRP program and explains why, from an operational standpoint, it is important that the Company have the proper mechanisms securely in place to ensure that this critical infrastructure replacement process can continue unimpeded to be timely completed within the proposed 10-year time frame.

Q6. MR. ROGERS ALSO RECOMMENDS THAT THE COUNCIL NOT ALLOW ANY GIRP INVESTMENT BEYOND THAT BUDGETED FOR 2019 UNTIL ENO DEMONSTRATES THAT THE INVESTMENT IS REQUIRED FOR THE SAFE OPERATION OF THE GAS UTILITY. IS THE PROPOSED GIRP INVESTMENT REQUIRED TO ENSURE THE CONTINUED SAFE OPERATION OF THE GAS UTILITY?

A. Yes. As outlined in my Direct Testimony, GIRP is required for the continued safe operation of the ENO gas system, now and into the future. It's important to note that it's inappropriate to categorize the operation of the gas distribution system in a binary fashion as "safe" or "not safe" since every individual leak condition presents the potential for gas migration and a corresponding risk for negative consequences. As described in more detail later in my testimony, the vintage, low pressure facilities in service today leak at a rate 250 times greater than existing polyethylene gas facilities. So, while the ENO system is safe and continues to operate safely, the remaining vintage gas facilities in operation today do not perform well and threaten the continued safe operation of the system. As a result, the Company seeks to mitigate the known risks associated with operation of its low pressure, vintage facilities through the proposed accelerated infrastructure replacement program. The overarching objective for the Company's gas business is to design, construct, and maintain the gas system in the City with safety as a priority while balancing customer needs, minimizing rate effects to customer bills, and maintaining compliance with applicable pipeline safety regulations.

As presented in Docket No. UD-07-02 (and from the discussion in my Direct Testimony in this proceeding),[2] the Company is required by federal pipeline safety regulations to implement an Integrity Management ("IM") program. Pursuant to this regulation, the Company's IM program[3] has identified and prioritized the risk inherent in the operation of a low pressure, vintage cast iron gas distribution system as the most significant threat to system safety and highlights accelerated replacement of these facilities as the most effective method for mitigating this risk. As discussed in more detail later in my Rebuttal Testimony, the accelerated replacement of vintage gas piping through the first two years of GIRP has translated into an over 25% reduction in total gas main leaks in the City.

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[2] *See* Bourg Revised Direct Testimony, pp. 1-11 and 20-21.

[3] The Company's IM program has been reviewed and accepted by ENO's pipeline safety regulator with the State of Louisiana's Office of Conservation, Department of Natural Resources, Pipeline Division.

The Company anticipates that gas system performance (as measured by gas main and service line leaks) will worsen as the existing vintage piping continues to age and fail, and without continued accelerated investment for infrastructure replacement through GIRP, an uptick in potentially hazardous leaks is anticipated. ENO's conclusion regarding the need for accelerated replacement of vintage piping is also strongly supported by other gas distribution companies that own and operate vintage facilities, the American Gas Association ("AGA"), and retail regulators[4] across the country. Based on the operational performance of the Company's vintage gas facilities and industry trends supporting accelerated pipe replacement as the most effective mechanism for addressing risks inherent in the operation of vintage gas facilities, there is no doubt that vintage piping materials currently in service in the City need to be replaced and replaced with a sense of urgency. The long-term efficiency and safety of the Company's gas distribution system depends on it.

The only issue appears to be the pace over which this replacement occurs.[5] The Company respectfully requests that the ten-year schedule described in my Revised Direct Testimony be approved by the Council. In addition to the safety issues described above, prolonging the replacement period beyond ten years will, in all probability, subject the Company's customers to general cost increases in labor, materials, and contractor costs. In addition, maintaining the ten year replacement period maximizes the likelihood that

[4] *See, e.g.*, Figure 1 in Ms. Bourg's Revised Direct Testimony, p. 18, "States with Innovative Infrastructure Cost Recovery Mechanisms."

[5] *See* Rogers Direct at 41. *See also* Docket No. UD-07-02 Rogers.

the work can be accomplished at a time when gas prices are at historically low levels. This will minimize the program's overall bill impacts on the customers, an important consideration for the Company.

Q7. SINCE YOU FILED YOUR REVISED DIRECT TESTIMONY IN THIS CASE, HAVE THERE BEEN ANY DEVELOPMENTS THAT UNDERSCORE THE IMPORTANCE OF COMPLETING THE COMPANY'S PROPOSED PIPE REPLACEMENT PROGRAM?

A. Yes. Since my Revised Direct Testimony was filed, the AGA issued a leading practices recommendations whitepaper[6] as a result of the Columbia Gas over-pressurization incident in September 2018 in Andover, Massachusetts.[7] While still under investigation, this tragic incident involved a vintage, low pressure gas distribution system, and the incident highlights the risks associated with operation of similar low pressure gas distribution systems. The leading practices whitepaper is included as Exhibit MPB-6 to my testimony and recommends replacement of all low pressure natural gas distribution components. This recommendation supports the continued accelerated replacement of the ENO low pressure gas distribution system.

6 https://www.aga.org/news/news-releases/aga-unveils-leading-practices-to-avoid-over-pressurization/.

7 https://www.ntsb.gov/investigations/accidentreports/pages/pld18mr003-preliminary-report.aspx.

Q8. PLEASE DESCRIBE THE OPERATING CHARACTERISTICS OF THE VINTAGE PIPE THAT HAS HISTORICALLY BEEN INSTALLED IN ENO'S SYSTEM AND PLANNED FOR REPLACEMENT UNDER PROPOSED GIRP.

A. From the late 1800's to the early 1900's, ENO's predecessor companies installed cast iron pipe to build out its distribution main[8] network. Cast iron was among the first materials available, and cast iron was typically utilized since it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. This pipe was buried to typical depths of between two and five feet, and if the soil beneath the pipe or to its side was disturbed and/or pressure was exerted on the pipe, it proved vulnerable to cracking. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, due to its degrading performance, the natural gas industry later determined that cast iron was unsuitable for high operating pressures. As a result, ENO lowered the operating pressure for its vintage cast iron system to low pressure, or one-quarter pound of pressure.

While cast iron pipe was being installed to build out the main network, ENO's predecessor companies were installing bare iron pipe that was coated with concrete at the time of installation for its service line[9] piping. This technique is commonly referred to as Boxed in Concrete ("BIC") piping. The concrete coating was applied by building a square wood box entirely around the pipe and pouring concrete into the formed box to

[8] Distribution mains are natural gas distribution pipelines that serve as a common source of supply for more than one service line.

[9] Service lines are the pipelines that transport gas to a customer's meter from the distribution main piping.

provide a protective outer cover. While many natural gas utilities were installing uncoated pipe during this time, ENO's predecessor companies had the foresight to install this outer coating to help prevent the pipe from corroding. While this installation method served its initial purpose, this coating practice is outdated and has proved to be problematic as the infrastructure has aged. Service line pipes of this type are experiencing a higher corrosion rate when compared to other service pipe types due to these service lines experiencing cracks in the concrete coating, which then exposes the resulting bare pipe to our area's moist soil. The age and the lack of an acceptable protective outer coating by today's standards require the accelerated replacement of these pipelines.

Q9. HAS THE COMPANY PERFORMED AN ASSESSMENT OF ITS LOW-PRESSURE GAS SYSTEM AND IDENTIFIED THE COMPONENTS THAT ARE MOST IN NEED OF REPLACEMENT?

A. Yes. Pursuant to federal mandate, the Company employs a risk scoring model to identify those components of its system that are most in need of replacement. ENO's IM program risk scoring model continues to rank natural forces and external corrosion on both cast iron main and BIC service piping as the highest risk for potentially hazardous leaks in the ENO gas distribution system.

Q10. WHEN DID ENO BEGIN REPLACING THE LOW PRESSURE COMPONENTS OF ITS GAS DISTRIBUTION SYSTEM?

A. While ENO has been replacing low pressure, cast iron pipe for the last 30 years, it did not begin replacing cast iron pipe in any significant amounts until it began replacing its flooded cast iron pipe in 2007 under its Gas Infrastructure Rebuild Program ("Rebuild"). While the Rebuild program officially ended in early 2017 once approximately $165 million in insurance and Community Development Block Grant ("CDBG") funds were exhausted, ENO continued accelerated pipe replacement under its GIRP program in accordance with Council Resolution R-17-6.

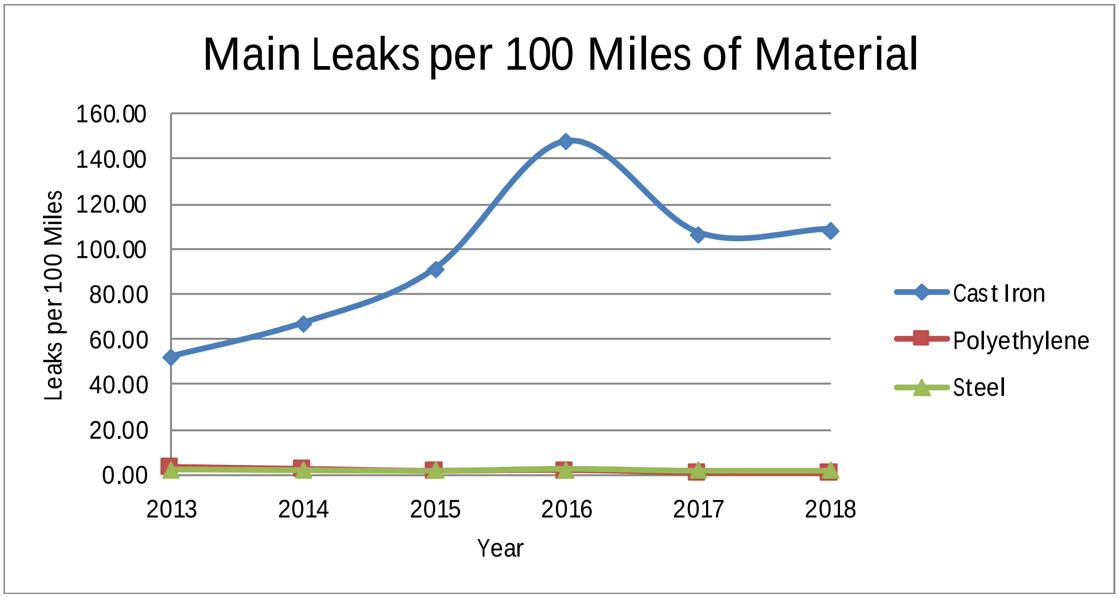
While ENO has made enormous progress since 2007[10] in delivering and maintaining a safe and reliable distribution system for its customers and continues to take reasonable and appropriate steps to operate and maintain a safe system, the system data is clear that vintage cast iron pipe and BIC service line piping continue to represent the greatest risk to the safe and reliable operation of the ENO gas system. ENO must continue to focus on the prompt replacement of these components to address the problems associated with aging infrastructure.

10 *See* Bourg Direct Testimony Figure 2 and Figure 3.

Q11. WHY IS IT IMPORTANT, FROM AN OPERATIONAL STANDPOINT, TO REPLACE THESE SYSTEM COMPONENTS AS QUICKLY AS REASONABLY POSSIBLE?

A. In addition to safety and efficiency concerns, the current leak (or operational) performance of vintage cast iron gas main and BIC gas service lines, as compared to the performance of more modern piping materials in the ENO service area, strongly demonstrates why these piping materials represent the top risk factors in the IM program. Charts 1 and 2 below provide historical performance for the ENO gas distribution system by pipe material type for gas mains and service lines, respectively.

Chart 1: ENO Gas Main Leaks per 100 Miles by Material Type[11]



Main Leaks per 100 Miles	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
Cast Iron	52.35	67.31	91.18	147.83	107.07	108.77
Polyethylene	3.35	2.46	1.54	1.94	0.69	0.43
Steel	2.76	2.32	2.10	2.80	2.08	2.13

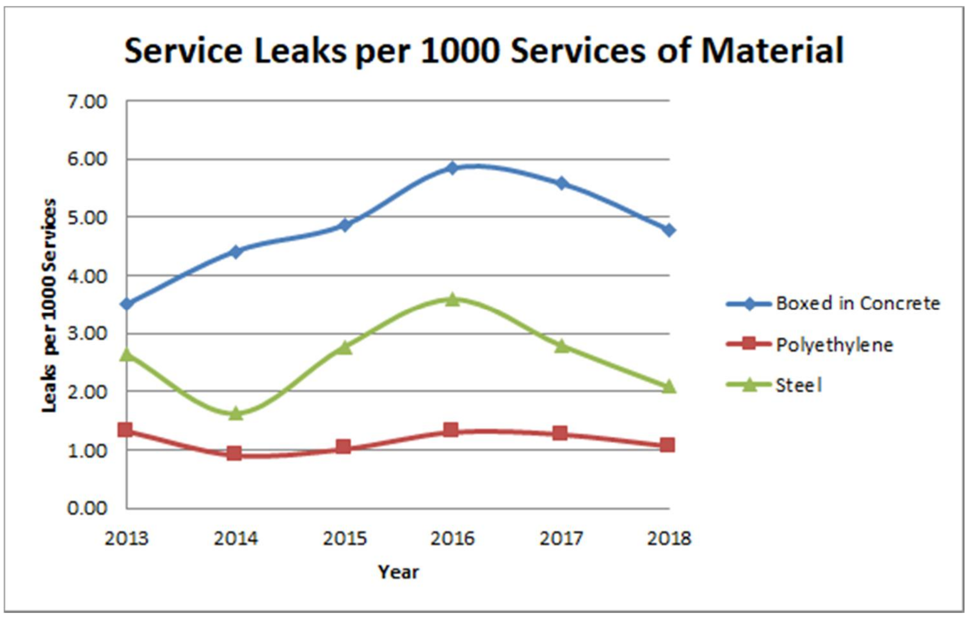
The gas main leak performance of 2017 and 2018 demonstrates that the GIRP program has been successful, in large part because GIRP allows the company to identify and prioritize replacement projects throughout the entire service territory instead of focusing only on pipe replacement in areas of the City flooded during Hurricane Katrina.[12] The continuation of gas infrastructure replacement through the Company's GIRP, together

[11] Miles of cast iron pipe in service as of the end of 2018 was 80 miles compared to 170 miles in service in 2013. A reduction of 90 miles or 53%.

[12] The Gas Infrastructure Rebuild Program that commenced in 2007 and concluded in early 2017 focused only on the replacement of infrastructure that experienced flooding during and immediately following Hurricane Katrina.

with ENO's leak repair practices, has allowed the Company to reduce its leak rate on these vintage pipe materials over the last two years. As the percentage of cast iron and BIC pipe in areas of the City that did not flood during Hurricane Katrina is reduced, ENO anticipates a significant reduction in leaks caused by corrosion and natural forces.

Chart 2: ENO Gas Service Leaks per 1000 Services by Material Type[13]



Service Leaks per 1000 Services	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
Boxed in Concrete	3.52	4.42	4.87	5.84	5.58	4.79
Polyethylene	1.33	0.92	1.02	1.31	1.27	1.07
Steel	2.65	1.64	2.77	3.60	2.80	2.09

13 Number of BIC service lines in service as of the end of 2018 was 11,488 compared to 26,166 in service in 2013. A reduction of 14,678 or 56%.

Therefore, it is essential that ENO continue to focus on and direct incremental (above annual baseline spending) capital resources toward this ongoing need. The replacement of vintage piping materials is an integral part of the IM program as it mitigates the most significant risks and threats inherent in the operation of the current ENO gas distribution system. And as a direct result, accelerated pipe replacement helps ENO demonstrate that its IM program is in compliance with federal pipeline safety regulations.

Q12. IS THERE ANOTHER SOLUTION FOR ADDRESSING THE ISSUES ASSOCIATED WITH CAST IRON MAIN AND BIC SERVICE LINES SHORT OF REPLACEMENT?

A. Not for the long-term. Corrosion leakage on cast iron main and BIC service lines does not slow down and the rate of leakage will only accelerate as the unprotected facilities continue to deteriorate. Cast iron and BIC pipe, much of it dating to the turn of the last century has reached, or soon will reach, the end of its useful life and must be replaced in a timely, cost-effective manner. In addition, ENO has received verbal guidance from the Pipeline Division in 2016 prohibiting the Company from making repairs on leaking BIC service lines. Rather, the Company must install a new service line from the main to the meter and cutoff the BIC service line to remove it from service when any leak is identified.

Q13. DO SAFE AND RELIABLE SYSTEM OPERATIONS REQUIREMENTS DEMAND ACCELERATED REPLACEMENT OF ENO'S CAST IRON AND OTHER LOW PRESSURE FACILITIES?

A. Yes. Continual system degradation due to unrelenting corrosion and other natural forces will challenge ENO's ability to operate the aged system safely and reliably. Operation of a low pressure gas distribution system is very difficult and inefficient from a leak management and leak assessment point of view. Leaks occurring on a low pressure system can often start out as very small leaks that can go unnoticed for long periods of time. Because they can go unnoticed, the potential exists for gas to migrate and later pocket in subsurface voids and/or become saturated in large areas of soil, making it very difficult to find the actual location of the leak. This is especially true in the New Orleans area because of the sandy and loamy soil found throughout the City. This condition may lead to potential public safety issues but can also lead to leaks being incorrectly pinpointed and not found in the first excavation, which creates unnecessary pavement restoration costs.

Pinpointing and repairing leaks on a low pressure system requires advanced skills and many years of experience, and as experienced field technicians retire, it has proven difficult to quickly train newer team members. It is often said throughout the gas utility industry that low pressure leak pinpointing is an "art" and not a "science".

Also, because of the amount of low pressure cast iron system being replaced and the manner in which it must be replaced, large areas of the Company's gas distribution system are now more prone to system reliability issues under maximum load conditions.

Therefore, continuing ENO's low pressure pipe replacement program is essential to ensure system reliability and minimize leakage and the associated public risks.

Q14. ARE YOU SAYING ENO'S SYSTEM IS UNSAFE?

A. No. The system continues to operate and be maintained in a safe and prudent manner by ENO today, as evidenced by ENO's ability to address leaks appropriately and timely. ENO places a strong focus on meeting federal and state pipeline safety regulations that govern the design, operation and maintenance of the City's gas distribution system. In the critical area of leak survey and leak repair, ENO's practices of performing more frequent leakage surveys and its focus on minimizing the duration and backlog of leaks requiring permanent repair exceed the required regulation.

However, while the ENO system is currently safe, ENO must plan now to ensure the continued safety and reliability of the gas distribution system into the future by addressing the systemic, ever-increasing risk posed by its degrading cast iron and BIC facilities.

And finally, while not identified as a top threat or risk in the IM program like cast iron and BIC services, the replacement of minimal first generation Polyethylene ("PE") piping infrastructure that remains in use in the City is also an area of focus for GIRP. Recent leak performance trends associated with the operation of ENO's first generation PE, coupled with increased industry focus on this poor performing material, mandate a measured replacement strategy.

Q15. WILL ENO'S LOW PRESSURE PIPE REPLACEMENT PROGRAM PROVIDE CUSTOMERS AND THE PUBLIC WITH ANY OTHER BENEFITS?

A. Yes. ENO is removing deteriorating portions of its system and enhancing the safety of its system by ensuring replacement of facilities with more modern, safer materials. This integrated, high pressure system will ensure that ENO's customers receive more predictable service with fewer interruptions. Replacement of vintage, low pressure piping facilities with modern, high pressure facilities will provide other benefits to customers and to the public, including:

- An integrated, higher pressure system that will allow for the installation of much smaller diameter pipe, which will minimize future potential conflicts with other underground infrastructure;
- A form of "storm hardening" in that the piping operated at higher pressures will not be as easily inundated by flood waters;
- The installation of Excess Flow Valve devices in customer service lines, which will operate to isolate any gas leak and enhance the safety of the gas service to the customer;
- Substantially reduce the current need for district low pressure regulator stations throughout its system; and thus, lessen the risk of an over-pressurization incident such as the over-pressurization incident that occurred in the Columbia Gas service territory in Massachusetts;
- An opportunity to install a small domestic sized regulator upstream of the meter to reduce the pressure before it enters the house, which will provide another layer of

defense against a potential over-pressurization event and the potential for associated property damage and/or injury;

- Flexibility for customers to add new high efficiency equipment, and allow for the installation of smaller, less expensive interior piping systems; and
- The ability for the Company to provide two-pound pressure delivery systems to customers, more readily allowing customers to install natural gas generators and other specialty appliances.

While replacement of the aging infrastructure has historically been driven by safety and reliability reasons, removing these pipe facilities also provides environmental benefits. Leaks from gas utility facilities have become much more of a concern in the past several years because of the negative environmental impact of gas leaking into the atmosphere. This is because the primary component of natural gas (methane) is a greenhouse gas that is much more harmful than carbon dioxide to the environment. Industry studies have shown that most distribution system emissions are estimated to be from cast iron and unprotected steel pipe, the pipe that the Company has targeted for replacement.

Finally, this massive and structural system replacement program is adding jobs throughout ENO's service territory, both in the ranks of full-time ENO employees, as well as the contractors who perform the actual pipe replacement and associated support services that are needed to execute this type of strategic replacement program.

Q16. WHAT DETERMINES THE SIZE AND SCOPE OF THE COMPANY'S PIPE REPLACEMENT PROGRAM?

A. The size of the Company's capital program is largely driven by the amount of pipe that needs to be maintained and ultimately replaced. Approximately 80 miles (or 4.5% of ENO's total inventory of main pipe) is cast iron operating at low pressure and is nearing the end of its useful life and another 65 miles (or 3.7% of main pipe) is operating at low pressure and requires replacement. At the end of 2018, the Company also had 11,489 BIC service lines operating at low pressure in service (11.65% of its total of 98,588 service lines) that need to be replaced. These service lines will consequentially be replaced as a result of replacing the low pressure main systems.

Q17. COULD THIS PIPE REPLACEMENT PROGRAM BE ACCOMPLISHED USING THE HISTORICAL BASELINE AMOUNT OF CAPITAL SPENDING?

A. No, not without significant safety and operational integrity risk. At the Company's normal baseline annual capital spend of approximately $3 million for planned infrastructure replacement projects, and the projected cost of approximately $[redacted] – $[redacted][14] to replace and abandon a mile of pipe, it would take over [redacted] years to install new facilities to abandon the entire 145 miles of remaining low pressure piping that remained in service at the end of 2018. This would also require a significant shift in the Company's strategy for planning and prioritizing its infrastructure replacement capital as

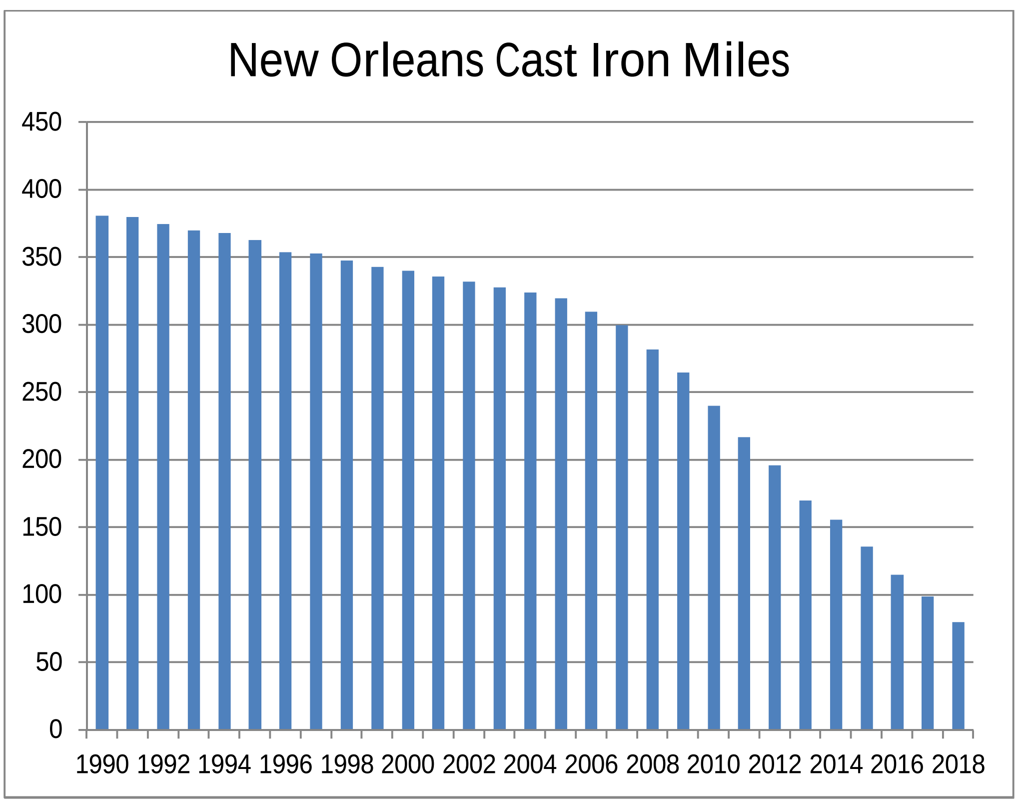
[14] This estimated range includes several factors, including location of pipe, complexity of installation, replacement piping material installed, and the amount of hard surface disrupted in construction process.

other competing priorities exist, including the need to replace gas facilities in conflict with City mandated projects.

Q18. HOW MANY MILES OF CAST IRON MAIN HAS BEEN ABANDONED AS PART OF INFRASTRUCTURE REPLACEMENT PROGRAMS IN NEW ORLEANS, AND HOW DOES THAT TREND COMPARE WITH THE PREVIOUS YEARS?

A. Between 2006 and the end of 2018, ENO abandoned 240 miles of cast iron pipe. In comparison, for the 10 years prior to 2006, ENO averaged only between 4.3 miles of cast iron pipe abandoned per year. Chart 5 below provides a total inventory of cast iron pipe in service in the City from 1990 through present.

Chart 5: ENO Miles of Cast Iron Main in Service



Q19. MR. ROGERS CLAIMS THAT "THE SCOPE OF ENO'S GIRP CHANGED" SINCE YOUR TESTIMONY IN DOCKET NO. UD-07-02. IS THAT THE CASE?

A. No. The GIRP scope, including the inventory of pipe to be replaced, has not changed. As explained in my Direct Testimony and subsequent discovery, the overall project objective (scope) of ENO's pipe replacement program has not changed since Docket No. UD-07-02 and remains focused on the retirement of all remaining low pressure and vintage PE piping remaining in service in the City. Mr. Rogers asserts in his Direct Testimony that "*…the scope of the GIRP now identifies that a significant amount of the estimated 238 miles of pipe identified for replacement will not be replaced, but instead abandoned…*[15]" To address this point directly, the Company introduced the concept of "abandoned" miles versus "replaced or installed" miles in this proceeding in an effort to provide the Council and its Advisors with additional clarity to support the actual cost of GIRP pipe installation since, previously, the Company tracked and reported abandoned miles only. This change is administrative in nature and in no way alters the original scope of GIRP, which focuses on the abandonment of all remaining low pressure and vintage PE piping and the build-out of new high pressure gas facilities to serve existing and future customers. The amount of pipe that needs to be installed and placed in service in order to take the low pressure pipe out of service (abandon) remains the same and is unchanged from Docket No. UD-07-02. This is accomplished by installing new high pressure pipe,

15 *See* Rogers Direct at 40.

placing the new pipe in service, and then abandoning the low pressure pipe once all customers have been converted to the high pressure system, hence replacing the low pressure system with a new high pressure system.

Q20. MR. ROGERS CLAIMS THAT "THE COST OF ENO'S GIRP CHANGED" SINCE YOUR TESTIMONY IN DOCKET NO. UD-07-02. IS THAT THE CASE?

A. With respect to the actual construction approaches and methods ENO anticipates will need to be utilized going forward, ENO does expect changes and anticipates upward cost pressure for replacement projects. The change in construction practices and factors creating this upward cost pressure include the following:

- The location of projects has a significant impact on cost. Many of the future projects will be in areas of the City that are all concrete and are much more densely populated.
  - o Pipe installation must be completed using an open trench installation technique, which requires much more restoration than when using trenchless methods;
  - o Hard surface projects have a higher replacement cost per foot than soft surface replacement projects that were able to be completed in other areas of the City;
  - o Pipe being installed is cathodically protected steel versus PE. Steel pipe segments are welded versus fused when using PE; and
  - o Higher levels of coordination with other utilities is required due to the amount of congestion in existing underground infrastructure. More offsets

are required to safely avoid underground facility conflicts, which complicates the installation of the pipe.

- Cost of pipe material. The mix of PE and steel mains needed in the Company's system can affect the average main replacement cost. For example, in the Central Business District of the City, far more of the facilities being replaced are designed and constructed with steel (vs. lower cost PE mains).
- Changes in City of New Orleans hard surface restoration requirements. The City of New Orleans expanded its paving restoration requirements on utilities such as ENO under its updated Utility Street Cut ordinance adopted in November 2015.[16]
    - In the past, it was typical that trench restoration would consist of simply paving the trench that was excavated for the main installation. Today, that same project frequently requires curb to curb milling and overlay.
    - For sidewalk construction projects, ENO may be required to replace larger segments of sidewalk, and to the extent that the existing sidewalk does not meet American's with Disabilities Act ("ADA") standards, ENO is required to make them compliant with current ADA standards. This means that ENO may need to install wheelchair ramps and curb realignment or replacement work.

[16] City Ordinance No. 26646 Mayor Council Series adopted November 5, 2015 and returned by the Mayor November 12, 2015.

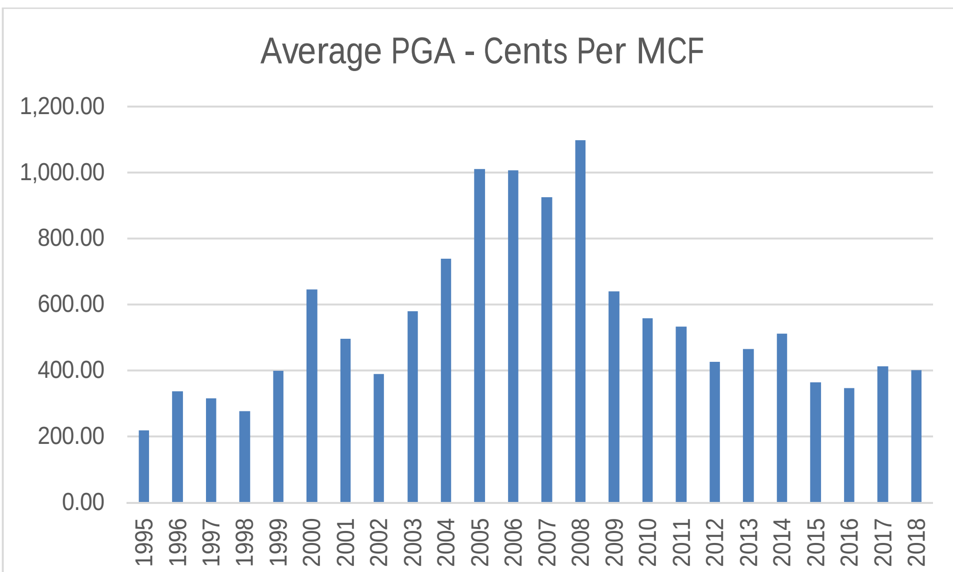
- Working in areas and properties that are governed by Historic Landmark Commissions, such as the Vieux Carre and Central Business District Historic Landmark Commission, have much more stringent requirements.
    - Locations of gas service risers and placement of meter and regulator stations often require additional provisions, and as such, are costlier.
- ENO's change in its gas pipe installation procedures to eliminate potential for utility conflicts, or cross bores, upon project completion.
    - Acceptable methods of verification are costly with sewer system video pipe inspection being a significant cost driver.
- Contractor costs are increasing. Contractor cost increases are driven by competition for resources as more natural gas utilities across the country undertake main replacement programs.

Q21. ARE THERE ANY OTHER REASONS WHY ENO RECOMMENDS THAT AN INFRASTRUCTURE REPLACEMENT PROGRAM BE COMPLETED WITHIN TEN YEARS?

A. The Company recognizes that continued efforts to modernize the ENO gas distribution system to ensure the safe and reliable distribution of gas now and into the future creates upward pressure on customer bills. The cost of natural gas purchased for resale in the ENO gas distribution system continues to remain at historic low levels, and during this period of low cost natural gas, the Company believes that the upward pressure on customers' total bills associated with infrastructure replacement can be best mitigated.

Stated more directly, all vintage cast iron and associated BIC service lines must be replaced in the foreseeable future, so the ideal time to make this investment is during this time of lower gas costs. Although gas prices may increase in the future, by increasing its capital investment to reduce the risk associated with vintage piping materials now - while gas prices are low - the Company is attempting to minimize the overall customer bills. Chart 6 below provides the ENO average annual purchased gas adjustment price from 1995 through 2018.

Chart 6: Chart Showing ENO Historical Average Purchased Gas Adjustment ("PGA") Prices By Year



Q22. WHAT IS ENO DOING TO MANAGE CONSTRUCTION-RELATED COST INCREASES?

A. ENO is focused on managing costs and making prudent capital investments that benefit customers and is taking the following steps to mitigate these cost increases:

- Periodically renegotiating with contractors and suppliers to ensure competitive pricing for materials and services provided to ENO;
- Installing smaller diameter high pressure PE in most areas of the City;
- Designing pipe installation projects to minimize street cuts and certain sidewalk locations; and
- Coordinating ENO gas replacement projects with the City of New Orleans Department of Public Works improvement projects to minimize excavation and restoration.

Q23. HOW ARE ENO'S CONTRACTING PRACTICES WITH POTENTIAL GAS UTILITY CONTRACTORS AFFECTING OVERALL CONTRACTOR COSTS?

A. ENO typically issues a Request for Proposals every three years for contractor services and enter into contracts with companies for three year terms in order to keep contractor pricing competitive and provide contractors with an incentive to remain operational in the New Orleans area. By providing contractors with a steady predictable pace of work, they are more able to preserve economies of scale, which in turn means lower contractor costs to the Company. It has been the Company's experience that assigning very small projects to contractors and starting and stopping contract crews can unnecessarily increase costs. It has also resulted in contractors leaving the area because there is such a high demand for contractor resources across the country due to the numerous utility infrastructure replacement programs. Therefore, it is important that the Company be able to maintain pipe replacement levels at levels similar to the current infrastructure replacement program so that it can retain a qualified and efficient contractor workforce.

Q24. IN RESPONSE TO THE QUESTION BEGINNING ON PAGE 41 OF MR. ROGERS' TESTIMONY, HE RECOMMENDS APPROVAL OF RECOVERY OF GIRP INFRASTRUCTURE COSTS INCURRED AS PRO FORMED THROUGH THE END OF 2019. DO YOU HAVE CONCERNS REGARDING MR. ROGERS' FURTHER RECOMMENDATIONS TO THE COUNCIL?

A. Yes. I am concerned about the continuation of GIRP, as well as its cost recovery, beyond 2019. Because of the critical nature, extensive scope, and long-term time frame of this transition away from a low pressure gas distribution system, the GIRP Rider proposed by the Company will ensure that the Company will comply with its IM program, and as a result, the Company's gas customers will reap the safety, reliability, and other benefits associated with this program. As further explained in the Revised Direct and Rebuttal Testimony of Mr. Thomas and in my testimony in this proceeding, it is crucial that the Company receive authorization to continue with pipe replacement. The Company looks forward to working with the Advisors to identify any potential opportunities to mitigate the cost impact to customers that may result from continued replacement of vintage/aging gas distribution infrastructure.

IV. NON-JURISDICTIONAL GAS CUSTOMERS

Q25. PLEASE DESCRIBE WHAT HAS BEEN REFERRED TO AS "NON-JURISDICTIONAL" GAS CUSTOMERS AND PROVIDE SOME BACKGROUND AS TO THE REASONS BEHIND THIS REFERENCE?

A. Non-Jurisdictional ("NJ") customers are a subset of industrial customers for whom the Company provides interruptible gas service. The Company provides NJ customers with interruptible gas service pursuant to negotiated special contracts. It should be noted that the Company first served NJ customers during the period that its predecessor, New Orleans Public Service, Inc. ("NOPSI"), was regulated by the Louisiana Public Service Commission ("LPSC"). It is my understanding that, both then and now, state law prohibits the LPSC from regulating the prices charged to industrial customers. It is also my understanding that several of the then large industrial customers operating in the City of New Orleans expressed concerns about rising operational costs and their future ability to stay in operation in New Orleans, with one of the major cost drivers being their natural gas service cost.

As a result, when NOPSI entered into contracts for the sale of gas to industrial customers in the City of New Orleans, those contracts were not subject to LPSC regulation. After the City Council regained jurisdiction over NOPSI, NOPSI petitioned the Council to allow it to continue providing service to these customers under the existing interruptible supply contracts and in a manner consistent with state law. The Council approved that request by Motion No. M-86-259. This NJ provision, when adopted by the Council in 1986, was well received and acted as an incentive for many of the city's industrial customers to maintain their operations in the City. At present, ENO continues to offer NJ service to industrial customers in the City to retain and attract new industrial business to the City since potential competitors in other areas of the state do not have price regulation for natural gas service.

Q26. YOU HAVE INDICATED THAT NJ CUSTOMERS ARE A SUBSET OF INDUSTRIAL CUSTOMERS FOR WHOM THE COMPANY PROVIDES INTERRUPTIBLE SERVICE. HOW MANY CUSTOMERS ARE INCLUDED IN THIS SUBSET?

A. ENO currently serves ten NJ customers. One customer has three separate accounts for natural gas service, for a total of twelve active NJ accounts.

Q27. PLEASE FURTHER DESCRIBE HOW PURCHASES ARE CURRENTLY MADE FOR NJ CUSTOMERS AND THE CONTRACT TERMS THAT DEEM THESE CUSTOMERS INTERRUPTIBLE?

A. First, gas supply purchases and upstream pipeline transportation charges made on behalf of the NJ customers are procured on an interruptible basis and are separate gas arrangements than those made for the other retail customers that are included in the monthly PGA filings. The NJ customer contracts specifically provide that, if at any time the source of gas supply to ENO is interrupted, the delivery of gas pursuant to these contracts would likewise be interrupted. The contracts also have a penalty provision for customers that continue to take service once they are notified that their gas service is being interrupted and before they can be physically shut off.

Q28. IN HIS DIRECT TESTIMONY, MR. PREP OBSERVES THAT THESE GAS CUSTOMERS ARE SUBJECT TO COUNCIL JURISDICTION. IS THIS YOUR UNDERSTANDING AS WELL?

A. I believe that the determination of jurisdiction is a legal conclusion and I defer to counsel on this point. However, I do agree that ENO has always recognized the Council's jurisdiction to determine the level of costs that would be borne by retail customers, including that investment necessary to maintain infrastructure to serve NJ customers. As such, ENO has historically sought approval from the Council where the revenues to cover the costs allocated to NJ customers was concerned, including the margins of these special contracts.

Q29. MR. PREP ESTIMATES THAT NJ GAS CUSTOMERS' ACTUAL ALLOCATED COST OF SERVICE WAS MORE THAN TWICE THEIR CONTRIBUTIONS TO FIXED COSTS. IS THIS CORRECT?

A. All existing NJ customers in the City are served from the Company's high pressure gas distribution system, with most served from large diameter feeder mains. In addition, the two largest NJ customers are in very close proximity to one of the Company's City Gate purchase points. For these reasons, I cannot agree that NJ customers' cost of service is more than twice their contributions to fixed costs. However, I do believe it would be appropriate to review the allocations of costs to these customers and determine if the pricing of their contracts remains appropriate.

Q30. ALTHOUGH MR. PREP DOES NOT ADVOCATE ANY CHANGE TO HOW THE NJ GAS CUSTOMERS ARE TREATED IN THIS CASE, HE DOES RECOMMEND THAT ENO BE REQUIRED TO PROVIDE A COMPLETE COST OF SERVICE ANALYSIS IN SUPPORT OF THE NJ CUSTOMERS' RATES AS PART OF FUTURE COUNCIL RATE ACTIONS. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. While ENO does not disagree with Mr. Prep's recommendation that NJ customer rates should be reviewed, it is ENO's opinion that placing the existing NJ customers on the current or proposed published Large General Service rate would not be in the customer's best interest for several reasons. First and most importantly, it would likely result in a material increase in the cost for gas service for this class of customers. By offering interruptible service under special contracts to these customers, gas service should be able to remain competitive with the prices available to other similar industrial customers with whom the ENO industrial customers are in competition.

The continued interruptible service under special contract to the subset of NJ customers also means that gas service to these customers can be rendered in a manner similar to the way gas service is provided to all other industrial customers throughout the state. In the other 63 parishes of Louisiana, natural gas prices paid by customers classified as industrial are a confidential matter between the customers and the seller; that is, the sales price of natural gas is not a matter of public record. While ENO certainly understands that many factors can come into play, requiring ENO to serve the NJ customers under a published tariff or divulge its sale price may place these customers at a competitive disadvantage.

Q31. HAS THE CITY COUNCIL ADDRESSED CUSTOMERS USING SPECIAL CONTRACT RATES FOR CUSTOMERS USING COMPRESSED NATURAL GAS AS A FUEL?

A. Resolution R-12-283 grants ENO permission to enter into contracts for natural gas sales for use in compressed natural gas vehicles. These negotiated rate, non-tariff contracts were used to promote the sales of natural gas and foster economic development in Orleans Parish. ENO believes that special contracts could still be used in the future for these purposes.

Q32. MR. PREP ALSO RECOMMENDS THAT THE COUNCIL INSTRUCT ENO NOT TO EXECUTE ANY NEW NJ CONTRACTS WITHOUT EXPRESS COUNCIL APPROVAL. DO YOU HAVE ANY CONCERNS WITH THIS RECOMMENDATION?

A. The Company does not object to this recommendation but would respectfully request that, if it were adopted, the Council also articulate standards regarding qualification for future “special contract” status so that prospective NJ customers have a clear understanding of what would be necessary to qualify as an NJ or "special contract" customers.

V. CONCLUSION

Q33. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My Rebuttal Testimony explains that the Company's low pressure gas piping must be replaced to maintain the long-term safety and efficiency of the gas distribution system. It also demonstrates that this activity should be completed over the next ten years to take advantage of both the current historically low price of gas and certain cost economies of scale that would not be available if the Company were to perform this work over a longer period. My Rebuttal Testimony also explains the competitive concerns associated with making the pricing information for NJ customers public. Although the Company has no objection to seeking Council approval before any new NJ contracts are executed if that is the Council's desire, the Company respectfully requests that, if this recommendation is adopted, the Council provide clear standards so that both the Company and prospective industrial customers will have a clear understanding of when these types of arrangements will be approved.

Q34. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

MICHELLE P. BOURG,

who after being duly sworn by me, did depose and say:

That the foregoing is her sworn testimony in this proceeding and that she knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, she verily believes them to be true.

Michelle P. Bourg

MICHELLE P. BOURG

Sworn to and

Subscribed Before Me

This 15th Day of March, 2019

NOTARY PUBLIC

Alyssa A. Maurice
LA Bar #28388-LA Notary 68053
Notary Public in and for the
State of Louisiana
Commission Issued for Life

American Gas Association

Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event

November 26, 2018

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The purpose of this document is to provide guidance to natural gas utilities on leading practices that may supplement current practices to reduce the possibility of an over-pressurization event, especially in a utilization pressure system. AGA's member companies are steadfastly dedicated to the continued delivery of natural gas in a safe and reliable fashion to the communities they serve. We are committed to sharing leading practices and lessons learned across our industry in order to enhance our collective performance.

Many of the leading practices described in this document are currently implemented at natural gas utilities but they are not uniformly applicable to all systems nor exclusive. This document contains practices above and beyond minimum federal regulations. Depending on each system's unique characteristics, it is the consensus of AGA members that appropriate implementation of the practices in this document may reduce the possibility of overpressurization. The determination of whether to adopt any of the items contained in this technical note is individual to each company, recognizing that not all practices will be applicable given the size, configuration, pressures, and other features of a particular system.

The need to implement every practice and the timing of any implementation of the practices described in this document will vary with each natural gas utility and the specific environment in which they operate. The actions within this document should be evaluated in light of each operator's system, geographic variables, the operator's independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their state regulators. Therefore, not all of the practices described in this document will be applicable to all operators. As used herein, the term "should" is not mandatory but is to be acted upon as appropriate.

This document is intended to serve as a technical resource for natural gas operators. Note that the appendix is an excerpt from an AGA publication which contains additional background information and practices which address overpressure protection and the related topic of system regulation.

Since the scope of this document is limited and primarily focused on practices to further reduce the possibility of an over-pressurization event, it does not identify leading practices in other areas, including emergency response. The reader should not conclude that the AGA members believe these are unimportant issues.

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Contents

Section 1: Design of Distribution Systems and Regulator Stations

Background of Natural Gas Systems

Natural gas utilities provide service to residential, commercial, and industrial customers. The typical source of the utility's gas supply comes from pipelines that operate at a high pressure. The high elevated pressure allows the gas supply to travel many miles underground throughout the country. For delivery to residential, commercial, and industrial customers, the pressure must be reduced to a lower pressure level that the customer can receive.

The gas industry has used pressure regulators to reduce pressure since the 1800s. The primary function of a pressure regulator is to maintain constant, reduced pressure at the outlet. This is accomplished by varying the regulator's position/opening such that the flow of gas through the regulator station matches the demand on the downstream system. As system demand decreases, the flow through the regulator decreases as the regulator responds to the increase in pressure in the system. Conversely, as system demand increases, the regulator flow must also increase (otherwise the system may run out of supply). The types of gas regulators available for selection by the gas industry range in size depending on the system demand being supplied. Despite their diverse sizes, they can be categorized according to application: appliance, service, industrial, and distribution/transmission systems. Just as there are many regulator choices there are also multiple points where regulators are used for pressure reduction. Common design points include city gate stations, district regulator stations, farm taps, industrial customers and residential customers.

City gate stations are a primary pressure reduction point for the high-pressure pipelines that transfer gas to distribution systems. The basic function of these stations is to link high-pressure transmission pipelines to distribution pipe systems. A city gate station usually performs three primary functions:

1. It reduces the pipeline pressure to operating pressure of the utility pipe system.
2. It measures the volume of gas delivered to the utility.
3. Odorant is added to the natural gas to enable the detection of gas.

District regulator (DR) stations are pressure-reducing facilities downstream of city gate stations that reduce the pressure in the pipeline coming from the city gate to a lower pressure. This lower pressure downstream of a DR is more suitable for providing service to customers or other distribution networks within the LDC's distribution system. The operating pressure of the distribution systems upstream of district regulator stations vary depending on the distribution systems configuration and downstream demands. The pressure of the distribution systems downstream of these DR stations usually vary from about 100 pounds per square inch gauge (psig) to as low as 0.25 psig. These downstream pressures may be categorized as high, medium, or low-pressure distribution networks. Although classification of pipe networks by pressure level is common, terminology and the pressure range covered by each class varies between utility operators and systems. System pressures are affected by a service area's demand with respect to customer usage needs, weather considerations, design loads, and other maintenance requirements.

High pressure networks offer service to residential customers either directly or by means of a medium or low-pressure distribution networks. Whenever gas is fed from a network operated at a higher pressure to one operated at a lower pressure, a pressure regulator is installed between the two points. A pressure regulator will reduce the higher pressure of incoming gas to lower pressure of outgoing gas.

The design criteria for each system are unique, leading to different designs for each regulator station. Some examples of factors that cause variations in regulator station design include:

- Maximum and minimum flow requirements based on the customers demand
- Upstream and downstream maximum allowable operating pressure (MAOP)
- Forecasted future flow requirements
- Maximum and minimum pressures available from the upstream system
- Number of stages for pressure reduction
- Number of supply inputs - fed by single or multiple supply lines
- Gas temperature and gas quality
- Location and environmental conditions, driven by local ordinances
- Amount of land or area available for the station to be built
- Gas contaminants (such as sulfur, liquids and particulate debris)
- Proximity to highly populated areas

Station design aspects that vary include:

- Type of regulator(s) or control valves installed
- Above Ground versus Below Ground
- The quantity of regulators installed
- Location of downstream pressure sensing points
- Type of over-pressure protection installed
- Use of heaters
- Equipment to remove contaminants from the gas stream
- Equipment to allow remote control of pressure settings
- Use of odorizers

Distribution systems are designed to provide safe, efficient, and reliable service to the customer. Customer fuel lines operate at low pressure to ensure proper appliance performance, typically less than 1 psig. A lower pressure system that delivers gas at minimum delivery pressure is sometimes referred to as a utilization pressure system. Consequently, it is not necessary to install a service regulator to reduce pressure for each customer when the system operates at utilization pressure.

Operating a system designed for minimum delivery pressure can be challenging as the needs of the system are dynamic and change with demand. Extreme cold weather days, customer demand changes, etc. require accurate pressure control. Utilization pressure systems have typically been designed as fully looped systems. Fully looped systems minimized customer outages by providing many alternative paths by which gas could reach the customer.

When a distribution system is designed at pressures higher than utilization, i.e., above the customers delivery pressure, service regulators are installed at the customer meter set to reduce and control the pressure to a uniform level to the customer.

The modern gas regulator is a highly reliable device; however, failures could potentially occur due to a number of reasons such as physical damage, equipment malfunction, and the presence of foreign material in the gas stream. The industry has developed multiple layers of protection to mitigate the potential of over-pressurization. While there is no design standard that is applicable to all situations, some common over-pressure protection designs include:

- Use of in-line monitor regulators that control pressure upon failure of the primary control regulator.
- Use of relief devices that vent excess gas pressure to the atmosphere.
- Use of automatic-shutoff devices, such as positive shut off valves and fail close regulators to interrupt the supply of gas.
- Installation of filters and strainers to eliminate debris entering a regulator.
- Deployment of signaling devices that notify operating personnel of equipment failure or abnormal operating conditions (AOCs).
- Use of telemetry and transducers that are monitored remotely with corresponding alarm set points.

Customers on systems that operate at pressures higher than utilization system pressures have their own individual regulator located at the meter. Customers served from utilization systems do not require individual over-pressure protection because the entire distribution system operating at utilization pressure has over-pressure protection at the district regulator station or at another location. The basics of over-pressure protection requires the design to protect the downstream piping system from excessive pressure.

Design Practices For all Pressure Classifications

The following practices should be considered when designing new regulator stations, modifying existing stations, or selecting over-pressure protection. System, environmental, and other factors unique to each operator will determine the applicability of each practice:

1. *Practice: Include pressure monitoring and alarm functionality within designs of systems and formalize approval via a Management of Change (MOC) process.*
   Description: Design for a mechanism to generate an alarm condition. Mechanisms may include: alarm relief (“whistle”, “tattle-tale”, “token”), full relief valves, pressure recording devices, pressure signals to Gas Control, etc. Critical pressure points should be capable of alarming or generating a real time notification (relief, whistle, token alarm to Gas Control or Operations, etc.) when an AOC occurs. Safety sensitive pressure monitoring points should be

field verified via the communications network to Gas Control. Field equipment should be calibrated and inspected to confirm alarm set points are properly configured to trigger at the appropriate upper and lower limits. Consider any modifications to critical regulators, pressure monitoring points and overpressure devices be validated through a formal MOC process.

2. *Practice: Design stations with remotely controlled valves and regulators.*
   Description: When designing new systems consider remotely controlled valves and regulators which may aid in the quick isolation of critical stations, where appropriate.

3. *Design for Response Time.*
   Description: When using monitor control valves and slam shut valves, recognize the inherent time to respond/time to close to enable adequate response. Equipment set points and operational characteristics should be taken into consideration.

4. *Practice: Size over-pressure equipment to current load and monitor for future load needs.*
   Description: Primary regulators, monitor regulators and relief valves must be sized and designed to enable adequate over-pressure protection. Parameters which dictate proper sizing, such as system demand requirements, must be evaluated. All station equipment must be designed to operate within its intended operating range. Periodically contact industrial customers to verify gas usage to understand if load patterns have changed, or if a significant change to their future load profile is anticipated. In completing this practice, operators should confirm system equipment is sized appropriately to deliver load and gas pressure safely.

5. *Practice: Design sensing lines to be protected and located close to or inside the regulator station.*
   Description: Sensing lines should be sized appropriately for the regulator and account for restrictions (i.e., reduced port ball valves, needle valves). Each regulator and relief valve shall have an individual sensing line, per 49 CFR Part 192 regulations. Sensing line taps should be located within the station side of isolation valves, and as close to the station as possible. If underground, route the sensing lines for supply regulators and over pressure protective devices to different locations to minimize the possibility of multiple lines being damaged by an excavation.

6. *Practice: Mitigate the possibility that a common mode of failure, or a single event, could take out the primary ("worker") and the monitor regulators.*
   Description: Single events can impact the primary and backup regulator. Determine what can be done to reduce the possibility that any single event can disrupt both regulators.

7. *Practice: Install slam shut valves, where practicable*
   Description: Installing slam shut valves is an option for over-pressure protection and loss of sensing pressure and maybe effective for additional system protection. Slam shut valves may be considered, particularly in systems where multiple regulator stations supply gas to an area.

8. *Practice: Create standard regulator station design templates that are approved by a licensed professional engineer or engineer with equivalent experience and technical knowledge.*
   Description: Establish standard designs for regulator stations. Require that any deviation from the standard should be approved through a design management of change (MOC) process that has been reviewed and approved by a licensed, professional engineer (PE) or engineer with equivalent experience and technical knowledge.

9. *Practice: Add or improve remote controls of stations and valves.*
   Description: Consider designing critical systems, including regulator stations, to be monitored and controlled remotely, or by a Gas Control room via a SCADA system.

10. *Practice: Design for atmospheric vent lines to be unobstructed for proper venting.*
    Description: In cases where vent lines are designed with below ground regulators, separate lines should be installed for each piece of control equipment and terminate so they are not impacted by water infiltration into the vault. Above ground facilities should be vented to avoid the impact of insects, ice, and environmental forces. Confirm that all vent lines are secured from motion or vibration.

11. *Practice: Above ground regulator sets and other critical regulator station equipment should be protected from vehicular and pedestrian damage.*
    Description: Bollards should be properly sized and installed to protect regulators from any potential vehicular traffic. Other considerations for protection include: locked fences around regulator stations, locked bypass valves, weather protection, and added protection for control lines from damage.

12. *Practice: Design for station security.*
    Description: Critical station valves should be designed with locking devices, as needed, so they can be locked in their normal operating position.

13. *Practice: Design bypass valve configurations for secure operation at stations.*
    Description: Two bypass valves should be considered in series to enable quick control if one valve fails during operation. To prevent unintentional operation, locking mechanisms should be installed on the valves when not in use. Consider locating bypass valves at a distance from operating equipment to confirm safe accessibility and operability in an abnormal operating condition, i.e. Fire Scenarios.

14. *Practice: Enhance regulator station design requirements in areas with a history of contaminants in the gas stream.*
    Description: Contaminants can impact pressure regulation equipment operation. Consider installation of a properly sized separator to remove rust, dust, liquids, or debris upstream of the regulator station. Consider installing heaters to reduce potential for freeze-ups and sulfur filters on pilot-operated regulation equipment in areas with known sulfur issues.

15. *Practice: Confirm flow path to relief valves are not compromised.*
    Description: Steps should be taken to not compromise the flow path to a system relief valve during construction (abandonments, new construction, reconfigurations, and renewals).

16. *Practice: Emerging technologies are monitored by the industry and should be considered in future over-pressure designs.*
    Description: When technology develops operators should consider, where feasible, to integrate new technologies that may enhance over-pressure protection.

Additional Design Practices for Utilization Pressure (i.e. low pressure "LP") Systems

In addition to the above, the following practices are options for operators to consider implementing, depending on the uniqueness of their LP system and the local environment.

1. *Practice: Design additional over-pressure protection on utilization pressure systems, where feasible.*
   Description: Consider adding additional layer(s) of protection for over-pressure protection. Design could include an operator, monitor, slam shut, full capacity relief valve, or a customer service regulator, where feasible.

   Consider utilizing relief devices throughout the system, particularly in a utilization pressure system fed exclusively by primary/monitor stations. This is an additional control to mitigate the potential for over-pressuring a system and also acts as an alarm. Urban environments may add additional complexity to finding a suitable location for the relief valve blow down stack. Locations can be at the regulator station or a distance downstream of the station.

2. *Practice: Design for new or replacement low pressure and utilization pressure district regulator stations to include pressure monitoring.*
   Description: Where practical, design the system so there is pressure monitoring of all utilization pressure stations and systems.

Section 2: Operating Procedures and Practices

This section includes guidance on Operational Procedures, Practices, and Standards that enhance the reliability and safety of natural gas systems affecting System Regulation, Regulator Station Design, and Overpressure Protection. It is the operator's responsibility to implement procedures and practices such that its natural gas systems are operated and maintained in a safe manner. Such practices may include, but are not limited to, the items in this section.

Regular maintenance for regulator stations

Regular inspections and maintenance activities can help determine that equipment in pressure reduction stations is working properly. The frequency of station inspections over and above regulatory requirements should be based on the following:

- The type of station (e.g., City Gate, District, Customer Sales, etc.)
- The type of equipment at the regulator station (i.e. remote monitoring)
- The configuration and number of the regulator runs at the station
- The style of regulators used (e.g., self-operated, spring-loaded, boot-style, pilot-loaded, pilot-unloaded)
- Whether the regulator is above or below-grade
- Historical performance of a particular regulator or station
- Gas quality
- System or sub-system throughput
- The amount of pressure cut, or differential, across the regulator station

Some of the regular maintenance activities performed on a station may include:

- Visual inspection of the station to identify risks and/or concerns that may have arisen since the last inspection
- Equipment functional inspections and calibrations
- Regulator operational inspections (visual inspection, check for regulator lock-up)
- Regulator maintenance inspections (regulator tear-down, inspection, cleaning, replacement of soft goods, filter inspection or replacement)
- Annual leak survey
- SCADA field electronic sensing equipment point-to-point verifications

System Monitoring

Strategically placed telemetry equipment monitors key parameters to assist with maintaining safe and reliable service. Telemetry systems include measuring instruments or detectors, a medium to transmit data, a receiver, and a system that records/displays data. If system control equipment is in place, an operator's Gas Control group monitors the data received, and either acts upon any alarms by making remote adjustments, or dispatches field personnel to investigate issues. Stand-alone electronic pressure recorders can also alert of an overpressure or under-pressure situation. If an operator has a SCADA system in place, these recorders can be programmed to send an alarm to Gas Control whenever system pressures fall outside acceptable levels. Operations personnel can be dispatched to investigate the problem.

Records

Complete records and drawings should be retained and documented on any work related to gas regulation or overpressure equipment, in accordance with the operator's records retention policy. This includes the location of all taps, control lines, and vent lines. As practical, records and drawings should include accurate dimensions and notations of as-installed conditions. Operators should consider having a system in place to make this information readily available to any field personnel who may need it, such as locating technicians. Mapping of all gas systems enables proper planning of system upgrade activities and maintenance. System interconnection points, pressure reduction stations and valves should be included in records.

Damage Prevention

Operators should work with their local One Call Center(s) to screen dig tickets that are in the vicinity of system gas regulation or overpressure equipment. Locates performed near system gas regulation or overpressure equipment should include marking the location of all taps, control lines, and vent lines. In addition, operators should consider monitoring excavation activity in the immediate vicinity of buried control lines and take necessary actions to protect them from damage.

Construction and Work Permitting Process

Operators should put in place processes and job-specific procedures for any planned work that could result in a significant interruption of gas flow to the network, require significant internal/external resource coordination activities, and/or involve multiple coordinated procedures. Procedures should identify all stakeholders when work is done on gas regulation or overpressure equipment that could cause adverse effects.

Tie-ins and Uprates

Tie in connections between two segments of natural gas piping typically take place between an existing pipeline and a newly installed pipeline, and often as part of Replacement/ Modernization Programs. During any tie-in procedure, pipeline pressures on both sides of the tie-in point should be monitored to:

- Maintain the pressure in the pipelines where the flow of gas is stopped;
- Prevent connecting mains with different operating pressures and MAOPs; and
- Verify that mains being connected are the ones intended to be connected to (not abandoned or operating at a different pressure)

Additional precautions should be taken when any work is done on or near system regulators and overpressure equipment. Field personnel should have a clear understanding of the impact that their work could have on a gas system, especially when working on utilization pressure systems where customers do not have secondary pressure regulation. Tie-ins and uprates should be done in a controlled manner where all departments, including Gas Control, are communicating as work is being performed. Decision points (go/no go) in the procedure should be identified and clearly communicated prior to initiating the pressure increase.

Standard Operations and Maintenance Practices

1. *Practice: Create and follow written procedures.*
   Description: Written procedures aid in successful execution of tasks and processes in projects. Common procedures should be standardized and included in the Operations Manual. Written procedures should be present or accessible from the job site. Complex work should be reviewed before being issued to the field, by all departments involved in the project. For example, when applicable, Engineering, Operations (contractors when appropriate), and Gas Control should review the procedures. In complex projects, a checklist can function as a written procedure. A process for approving field changes to a procedure should be specified. Operators should consider requiring review and approval of complex procedures by a licensed professional engineer (PE) or engineer with equivalent experience and technical knowledge.

   Procedures should contain the necessary steps in proper order to be completed prior to beginning field work (such as verification of accessibility of valves and their position, below ground fittings, all isolation points, and operating conditions of the system, etc.). System designations and operating pressures should be in the procedures to ensure recognition of over or under pressure event. Restrictions or AOC's that alter a procedure (weather, generation load, etc.) should be accounted for and a process for approving field changes should be specified. Refer to section (D) of this section for records retention.

2. *Practice: Use appropriate personnel and equipment to monitor pressures during work.*
   Description: Use calibrated gauges, of the type and pressure range suitable for the system being worked on and continuously observe in appropriate locations to monitor the operating pressures of the system during any activity that could potentially cause over-pressurization. Leave gauges on for an appropriate length of time after the work is completed, to identify any lagging pressure changes. Consider the use of qualified pressure control personnel to monitor the operation of regulator stations within the scope of work.

3. *Practice: Consider eliminating direct connections between systems operating at different pressures.*
   Description: If this configuration is part of emergency pressure support of a system, the valves should be labeled, locked out/tagged out, and clearly identified on all maps. Consider adding gauge connections on both sides of these valves. Prevent operating a valve that connects a higher pressure system to a lower pressure system, especially a utilization pressure system.

4. *Practice: Lock and tag all bypass valves.*
   Description: Regulator station bypass valves should be locked and tagged to prevent unintended or unauthorized operation resulting in an AOC. Provide security around bypass valves if unlocked. Consider a special valve key or valve cover preventing anyone other than qualified staff from operating a regulator station bypass valve. The need for locking devices should be balanced with the weather and environmental conditions of the area and the

impact on emergency response. Consider implementing a formal Lock-out Tag-out (LOTO) program to expressly spell out when LOTO is required and how it protects the operator from overpressure events.

5. *Practice: Exercise critical valves prior to initiating a procedure.*
   Description: Operations personnel should confirm location of all valves that are critical to isolation of a work area or a pre-determined valve isolation plan. Operator should exercise critical valves to verify that they are operable. Confirm that the critical valves can be operated, while monitoring system pressures on both sides of the critical valve. See Practice 2 above regarding pressure monitoring and use of gauges while operating valves.

6. *Practice: Written procedures should include AOCs.*
   Description: The expected range of pressures during the procedure, as well as the MAOP of the system should be communicated to personnel in the field and control room, if the utility has a gas control. Actions to take in response to abnormal pressures should also be communicated. Field personnel should verify the pressure and/or flows measured in the field are the same as what the Gas System Controller is observing in the control room, when applicable. Emergency contact information for gas company personnel and emergency first responders should be available/accessible to everyone on the job site.

7. *Practice: Develop a standard written procedure for notifying emergency first responders and provide clear instructions on relief devices.*
   Description: Both Dispatch and Gas Control operators should use the same set procedure to notify emergency first responder personnel when there is an AOC. If the notification is to inform first responders that a relief valve is blowing, the caller should also inform them that the equipment is operating as designed, and that the relief device should be allowed to continue relieving pressure.

8. *Practice: Pre-job briefing (tailboard meeting) to review procedure before beginning.*
   Description: A briefing with Operations personnel performing the work should be held. Updates to the job briefing should occur based on changing conditions (weather changes, shift changes for employees, transitioning between day shift and night shift, significant delays between start and finish of procedure, etc.) Identify scope of work involved and involve Gas Control, if applicable, when the procedure will result in a significant change in system pressures or when over-pressurization is a threat. Verify SCADA equipment that is being used as flow/pressure monitoring is properly communicating to control room on the day of work being performed.

9. *Practice: Data refresh rate awareness and timeliness.*
   Description: During standard operations or procedures, Gas Control should be aware of how often SCADA sites are polled, and adjust responses accordingly. When possible, consider increasing frequency of polling on systems where active work is being performed on facilities considered to be critical, to set an appropriate time between readings.

10. *Practice: Planned maintenance work should be communicated to Gas Control.*
    Description: For systems that have a Gas Control, consider establishing communication protocols based on the significance and potential impact the maintenance work may have on field and control room operations.

11. *Practice: Maintain awareness of activities in the upstream system to confirm system changes or work performed has not compromised pressure regulation equipment.*
    Description: Operators should consider a means to minimize the potential for fluid and debris to enter the gas stream and perform inspections after work is performed upstream of a regulator station, as needed, to mitigate the potential impact of any debris or liquids that entered the regulator station. For example, transmission in-line inspections may dislodge scale and debris which could travel downstream into regulator stations.

Construction, Tie-Ins, Tapping, Uprates, and Abandonments Practices

1. *Practice: All regulator control lines and service lines to structures in the area of excavation work should be located.*
   Description: The written procedure and the locate markings should indicate if the lines are connected to the main being worked on. Structures at street intersections and main crossings are particularly vulnerable. Pressure regulator control lines within the excavation area should be exposed by hand or with soft-dig excavation equipment and protected during excavation. Facilities that were incorrectly mapped or unmapped should be documented and communicated to the appropriate group to be added to the map or corrected.

2. *Practice: Prior to an uprate operation, evaluate the location and placement of any pressure regulator equipment, control lines, and relief valves in regards to the uprate strategy/plan.*
   Description: An uprate procedure is a detailed process to change the MAOP of a system to a higher pressure based on system design, construction and pressure test. The procedure should include a review of the existing regulator stations to determine if their locations are acceptable and the installation meets system demands and company standards. A review of the operating history of the regulator station should also be conducted, where applicable. The results of the review and any changes, modifications or new installations should be included in the procedure and appropriately sequenced. Operators should require review and approval of system uprates by a licensed professional engineer (PE) or engineer with equivalent experience and technical knowledge.

3. *Practice: Simplify complex procedures by breaking into multiple, less complex procedures.*
   Description: Considerations should be included during project planning to maintain manageable scope of work activities and procedures. Complex projects with numerous tie-ins or other involved work activities could be broken into multiple manageable procedures to reduce risk of unforeseen abnormal conditions.

4. *Practice: Work-in-Progress and Work-in-Planning notations ("clouds") on maps.*
   Description: Construction planners should identify and notify all affected departments of planned construction activity. A drawing should be provided to visually identify all impacted work areas across multiple departments or service areas. This can prevent separate groups from performing work on the same, or related systems and creating operational issues.

Damage Prevention Practices

A serious threat to the integrity of a natural gas facility is the possible damage resulting from excavation, external forces, or pedestrians around piping and regulator stations. Damage to the piping near a regulator or the control lines of a regulator can cause an AOC (abnormal operating conditions), sending high pressure gas downstream. Below are some of the practices in which the threat of such damage may be mitigated.

1. *Practice: Establish buffer around the regulator station for One Call tickets.*
   Description: All one call tickets should be reviewed to determine location and prioritized if near a regulator station. Consider a set perimeter for prioritization such as "within X feet" of a station. Extra precaution should be taken in these areas, and procedures should be developed to reflect the extra actions to be taken by inspectors, personnel observing 2nd and 3rd party excavations, field operations personnel, etc. The benefits of technology, such as GIS, should be considered to recognize these buffer zones, potentially automating the prioritization of one call tickets

2. *Practice: Have operator personnel on site observing 2nd or 3rd party excavation activities in close proximity to regulator stations or mains with buried control lines.*
   Description: Operators should consider having qualified personnel monitoring construction within the specified buffer zone around regulator stations with buried control lines. This provides trained response to abnormal conditions that may occur during the work, including stop work authority. This person should conduct pre-construction meeting with the 2nd or 3rd-party construction crew prior to any work being performed to explain the importance of avoiding any damage. The excavator should hand dig or use another form of soft digging technology when digging around a regulator station. Consider shutting-in stations, when possible, or putting them on local control.

3. *Practice: When working in the vicinity of regulator stations and utilization pressure systems, create a process to identify potential AOCs.*
   Description: Operator should provide field personnel with a standardized checklist that covers threats that could cause an AOC. Confirm the checklist is used prior to performing work.

4. *Practice: Locate and maintain marks for buried control (sensing) lines.*
   Description: Locate and mark all buried control lines and associated piping. Hand dig or use soft dig technology to excavate around control lines. Consider installing above ground signage, below grade protection plates and/or marker balls to indicate buried gas utility piping below to increase awareness.

5. *Practice: Protection of control lines at regulator stations.*
   Description: Measures to protect control lines include installing with hard pipe or heavy wall stainless steel tubing, or locking or securing by some other means such as taking off valve handles, and eliminating the ability to shut a control line valve without a wrench.

Records Practices

Records are critical for operations, maintenance, risk identification, and analysis. Operators should have a documented process for creation, collection, identification, distribution, and storage of records. The process should identify authority and responsibility for managing records.

1. *Practice: Use maps and records on site to complete work*
   Description: Utilize appropriate maps, records, and construction drawings to complete work as designed. Perform a mapping system review in coordination with the applicable personnel, such as representatives from engineering, pressure control, and gas control, when applicable, to validate and update that control line and pressure sensor locations are shown in the mapping system as needed. Utilize records and maps of all interconnects and regulator stations feeding into a given system. Regulator Station drawings should be field verified for control line locations and be available to company personnel onsite at the station. If station operation is part of the procedure, a drawing of the station should also be a part of the work package. Control point locations should be accurate and updated during any field working procedure. Verify accessible valves and their position (normally open are open, etc.), below ground fittings, and operating conditions of the system should be performed as needed. All gas supply interconnects and location of company owned facilities need to be mapped or in written form.

2. *Practice: Implement a Records Management System*
   Description: Records management systems can track equipment in the system, as well as maintenance records of the equipment. Consider a system that can notify the responsible parties in advance of maintenance schedules for pending work.

3. *Practice: Management of separation valves.*
   Description: Valves that separate systems operating at different pressures should be eliminated, where possible, as noted under Standard Operations and Maintenance Practices, Practice 3. If it is not possible to eliminate separation valves, they should be clearly indicated both on system maps and in the field. *This practice is <u>not</u> applicable for station bypass valves.*

4. *Practice: Labels for critical valves should indicate the direction to open/close and number of turns to full open or full closed.*
   Description: Asset labeling in the field should include not only the critical valve number as shown in the record management system and on maps and station drawings, but also indicate which direction the handle or wheel should be turned to open and close the critical valve,

and the number of turns to move the critical valve from full open to full closed. Alternatively, this information may be provided to field personnel via electronic devices.

5. *Practice: Collect and maintain precise location data for equipment, sensors, critical valves, and control lines, where possible.*
   Description: When field personnel are performing maintenance on equipment in the field, consider taking GPS readings or precise measurements. Include in records for all pressure sensors, regulators, critical valves, and control lines.

6. *Practice: Complete and retain the as-built drawing for the installation or reconfigurations of pressure regulation assets in a timely fashion.*
   Description: Upon completion of pressure regulation asset installations or reconfigurations, field mark-ups should be verified and updated into a records system for all assets related to pressure regulation.

Section 3: Human Factors

Understanding and addressing human factors is critical to reducing the frequency and severity of pipeline incidents caused by over-pressurization. Considerations include:

- Promote a positive pipeline safety culture, which influences the attitudes of employees and contractors regarding pipeline safety and drives a conscious effort to reduce the risk of over-pressurization.
- Identify and communicate to all personnel safety-critical tasks for each project and system operation tasks that may result in over-pressurization if procedures are not followed. Encourage use of error prevention tools such as 3-way communication.
- Identify all personnel performing the task are qualified for the task.
- Identify AOCs and the appropriate actions to be taken should they occur by involving construction, operations, gas/pressure control, and design personnel.
- Identify where human failures have a high likelihood of occurring during each step of a task and determine measures to prevent or mitigate the likelihood of over-pressurization occurrence.
- Wherever possible, design the system to account for the possibility of human failure as discussed in Sections 1 & 2, minimizing the potential for human error in the operation or maintenance of the system.

Management of Change (MOC)

MOC process is a leading practice for evaluating and mitigating the risk of significant changes to a pipeline system. Operators should consider developing a MOC process for all plans that have a potential for over-pressurization. The process should communicate the level of authority required to make changes to the design and/or written project plan. For example, inspectors and/or operator personnel may have authority to make certain types of field changes, while more complex changes may have to be approved by a licensed PE or engineer with equivalent experience and technical knowledge.

Training for Prevention and Recognition of Abnormal Operating Conditions

The training of operator and contractor personnel for executing construction, operation, and maintenance activities is essential. Personnel should be well-trained to perform their assigned duties. Prior to the start of construction, the operator must determine the knowledge level and skill set required to perform covered tasks. It is the responsibility of the operator to verify that personnel are qualified and have the knowledge skills and ability to perform each task assigned to them. Each employee or contractor must demonstrate a fundamental knowledge of performing the task including recognizing AOCs involving over-pressurization of a system along with possessing the technical and operational experience required to perform the work safely.

Due to the unique operating characteristics of a utilization pressure system, gas utility, contractor, and inspector personnel should have additional training on the different operating characteristics of a utilization pressure system. Gas utility and contractor personnel must be trained on how to recognize AOCs and what responses are required to mitigate or minimize their impact. AOCs associated with operating a utilization pressure system should be identified and operational actions defined to address these AOCs. In addition, design and gas control personnel should consider specific training on the operating characteristics of a utilization pressure system and the importance of ensuring the accuracy of the plans and documentation of all proposed work such as tie-ins, abandonments, critical operating valves, regulator stations, regulator station sensing lines, location and adequacy of over pressure equipment, uprating procedures, proper operation of SCADA system, response to SCADA alarms, and the identification of AOCs. When necessary, design personnel should make field visits to determine the accuracy of maps, as built documentation, location of critical infrastructures including regulator sensing lines, and SCADA locations as part of the project design.

Designing a safe, reliable, and efficient gas delivery system requires system knowledge and expertise. Some gas utilities require a licensed PE or engineer with equivalent experience and technical knowledge to design regulator stations and over-pressure equipment.

Operator Qualification (OQ)

An essential part of the work planning process is the identification of all covered tasks prior to the project commencing. Only qualified individuals or a person under the direct span of control of a qualified individual (when allowed) can be assigned a covered task. As part of the work plan, the covered tasks should be identified for each step of the process and incorporated into the work plan.

During the construction phase, the inspector(s) or company representative(s) must be fully aware of the operator qualifications of all individuals' including those who are performing a task without supervision and those who will be required to perform tasks under direct line of sight observation of another qualified individual. Anytime there is a change in personnel on the construction crew, or the procedures change, the operator qualifications should be re-verified.

Field Oversight

Field oversight including inspection, quality control and quality assurance measures of qualified personnel should be considered throughout construction, maintenance and operations processes. The level of inspection is specified by company policy and includes additional provisions for more complex projects and/or work tasks.

It is the operator's responsibility to provide documented procedures for qualified personnel detailing the step by step guide that directs them through a pressure system control work task. Field oversight activities can help with the understanding and execution of documented procedures during natural gas construction and operations, especially when the work sequence of events is extremely important and adherence to the documented procedure is critical to prevent over-pressurization of the system. For instance, field oversight can prevent a critical step or steps from being missed or not performed in the correct sequence, avoiding an abnormal operating event that could adversely affect the safety of the system.

All documented procedures and qualifications should be present on the job site or accessible per electronic means. For job specific procedures the person or person(s) in charge should be noted on the procedure or job briefing form. In addition, emergency contact information should be included for additional personnel, if needed.

Prior to starting construction, all appropriate personnel should meet to review construction drawings, contract specifications, design criteria, schedule, critical task list and task assignments, and OQ qualifications, and review AOCs to verify that all personnel are using the most current construction documents.

Management of Change Practices

As noted above, MOC is a formal procedure used to identify and consider the impact of changes to pipeline systems and their integrity. Management of change shall address technical, physical, procedural, and organizational changes to the system. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

1. *Practice: MOC process should govern proposed job changes during the construction phase, including appropriate approvals, signoffs, and communications on projects that have a potential for an over-pressure event.*
   Description: The MOC process should address the level of authority required to make changes to the design and/or written project plan. These procedures should be understood by the personnel using them and should address technical, physical, procedural, and organizational changes to the project.

2. *Practice: Clear delineation of authority during system work*
   Description: Delineation of authority should be clearly stated in the plan by including the critical task and the operator personnel responsible for approvals.

3. *Practice: Stop Work Authority must be granted to all personnel*
   Description: Each employee should be granted the accountability and responsibility to halt work not conforming to specifications, OQ qualifications, proper/safe construction methods, and specified job tasks.

4. *Practice: Operators should endeavor to collect and report near miss information and encourage the sharing of safety-related events.*
   Description: Operators should view near misses as learning and development opportunities. Near-miss incident investigations provide opportunities to implement new or revised procedures and address deficiencies and prevent similar events from recurring.

Training for Prevention and Recognition of AOCs Practices

Personnel must be sufficiently trained to recognize and react to AOCs during routine and construction work. Operators should consider utilizing the following practices to respond to AOCs:

1. *Practice: Train gas operations personnel on what occurs in the structure during an over-pressure event, including the potential consequences of the event.*
   Description: Operator should define additional AOCs for utilization pressure systems. Field service personnel need to be trained on how to recognize and respond to these AOCs to mitigate or minimize the impact to customers.

2. *Practice: Provide specialized training for field personnel to highlight the unique characteristics of working on utilization pressure systems.*
   Description: Due to the unique operating characteristics of a utilization pressure system, operator, contractor and inspector personnel should have additional training on the operating characteristics and AOCs associated with utilization pressure systems.

3. *Practice: Provide formalized training for design personnel.*
   Description: If the utility operates a utilization system, both construction personnel and design personnel should be properly trained on utilization pressure systems and the importance of ensuring the accuracy of the documentation of all tie-ins, abandonments, critical valves, regulator stations, regulator station sensing lines, location, and adequacy of over-pressure equipment and uprating procedures.

4. *Practice: Enhance the current AOC OQ covered tasks to include over-pressurization.*
   Description: Operators must review their AOCs to verify over-pressure of all operating pressure systems are addressed and actions developed to minimize or mitigate the impact.

Field Oversight Practices

Coordination between construction, control rooms, and field personnel is critical to safety. Practices to enhance coordination are listed below:

1. *Practice: Coordinate and communicate work activities to all parties involved in the project prior to initiating the next step.*
   Description: Operators should incorporate a process where field operation activities are coordinated through Gas Control or similar group to verify there are no new issues or constraints impacting the ongoing work. Constraints/issues could include work being done in adjacent systems that could adversely impact the construction plan. (i.e. working on a regulator station; operating critical valves; taking a critical line out of service, etc.)

2. *Practice: Permission to proceed needs to be clearly established, and a defined person in charge must be known by all on the job.*
Description: Personnel responsible for clearing critical tasks should be identified and communicated to those involved on the job.

3. *Practice: Written procedures must be followed in the appropriate sequence.*
Description: Work step sequencing is extremely important and should be understood and followed by all personnel involved in the task. Doing work out of sequence may result in over-pressurization or other emergency conditions. Employees and contractors should be empowered to exercise Stop Work Authority, if the sequence of work is not followed.

4. *Practice: Require employees with system pressure expertise to attend design/construction planning meetings, including Gas Control and Operations personnel, when appropriate.*
Description: Operator work plans should include the various stages of the design approval. Each operator should determine when, during the design phase, Gas Control and Operations personnel should be included in the planning.

5. *Practice: Be prepared to rotate qualified staffing during lengthy procedures.*
Description: To prevent fatigue and comply with hours of service requirements, employees should be given rest breaks during lengthy procedures. A resource plan should be developed for long duration projects and incorporated into the project specific procedure. The resource plan may include details such as the number of qualified individuals necessary to complete the various steps in the procedure. Additional resources should be identified in the plan in the event the duration is longer than expected.

Section 4: Managing the Risk of an Over-pressurization Event

Distribution Integrity Management

Since 2011, natural gas distribution system operators are required to have a Distribution Integrity Management Program (DIMP) in place. DIMP programs confirm gas distribution system integrity by identifying system threats addressing risks these threats pose. The Gas Piping Technology Committee's (GPTC's) "*Guide for Gas Transmission, Distribution and Gathering Piping Systems*" contains a list of primary categories of threats and, of these, Equipment Failure and Incorrect Operations include factors which could lead to over-pressurization. Each system is unique so each operator must perform its own evaluation to identify the risk of over-pressurization to its system. Once identified and evaluated, the methods of mitigating the threat of over-pressurization include system design, modification of operating procedures, and additional personnel training. Earlier sections of this paper discuss these measures in detail. An operator's DIMP plan will not list all individual steps but should require that the programs and the person(s) responsible for that program are identified and included in the Operations & Maintenance plan. DIMP plans are dynamic in that they change as the system and conditions change and they must include the process for review and updating the plan.

In risk management terms, over-pressurization can be considered a low frequency event and consequence can vary from low to high, depending upon the design of the existing station and associated system. These types of events can be difficult to model due to the low number of data points. If an operator elects to consider over-pressurization as a threat, they should then estimate the consequence factor based on (1) an analysis of industry data, (2) a data-based calculation, and/or (3) Subject Matter Expert input. An operator may also elect to consider sub-threats of over-pressurization. For example, as part of a risk ranking model, low pressure cast iron may be assigned a higher risk score than one determined by leak history alone. For a system-wide risk model, regulator stations may be assigned a higher consequence score where they supply a utilization pressure system.

Should an operator determine that over-pressurization is a threat to their system, measuring the effectiveness of mitigation measures is very difficult for infrequent events and may involve reducing a frequency that is already extremely low or near zero. However, tracking and reporting identified improvements can show where potential gaps in the process are being addressed. Some examples of accelerated actions for incorrect operations from the GPTC guide are: improve procedures, improve training, evaluate locations where inadequate practices may have been used, and perform internal audits or inspections. Performance metrics can be applied to any of these.

The intent of the DIMP regulation is to allow an operator the flexibility to address its own system-specific threats. Cast iron, bare steel, and vintage plastic pipelines are a quantifiable risk and for gas utilities whose rates are set by their state, effective rate recovery mechanisms are in place for 43 states and the District of Columbia for replacement of vintage pipe, as of the publish date of this document. Mitigating the risk of over-pressurization should also be addressed through rate recovery mechanisms.

Support from stakeholders, communities, and customers

Many utilities are modernizing their distribution pipeline systems featuring utilization pressure. There is a significant amount of collaboration and support needed from various parties to upgrade these legacy systems to higher delivery pressures.

As an example, many customers resist moving their meters to an outside location. Relocation of the meter generally involves work that must be completed on the piping inside the home. In addition, some communities are considered historical districts, and resist the utility's efforts to move meters outside due to concerns with aesthetics or space limitations.

It is a leading practice for a gas utility to engage and secure the support of cities, towns, and counties in replacing utilization pressure systems. Streets and roads, along with other underground infrastructure, are greatly impacted by these upgrades. Gas utility operators and the communities they serve must work closely to develop plans that are workable for all stakeholders. Placement of pressure regulating stations and relief valves aboveground and/or in public right of way may need support by local communities to mitigate the risk of over-pressurization.

In addition, some utilities have worked with local public utility commissions to secure support for these types of issues in conjunction with a pre-approved rate recovery mechanism for infrastructure upgrades.

General Practices

The following general practices are options to be considered in managing the risk of an over-pressure event:

1. *Practice: A natural gas utility should look for opportunities to work with all stakeholders to pro-actively upgrade its utilization pressure systems.*
   Description: System pressure upgrades often require customer cooperation with moving meters outside and performing other work inside the home. In addition, support is typically needed from municipalities for installing pressure regulator facilities, particularly in historical districts. Effective cost recovery is needed to fund modernization of these gas systems. As cast iron and bare steel pipe are replaced, consider where it is feasible and practical to convert utilization pressure systems to higher pressure systems.

2. *Practice: Define risk criteria for overpressure events.*
   Description: Operators should track the number of overpressure events within their systems and evaluate for trends. Operators should conduct root cause evaluations or apparent cause evaluations for significant overpressure events.

Industry practices specific to DIMP:

1. *Practice: An operator's DIMP plan should incorporate existing programs and accelerated actions taken to reduce the risk of over-pressurization, if it is identified as a significant risk.*
   Description: Determine what actions and initiatives should be implemented to reduce the risk of over-pressurization, considering the probability of occurrence and the consequence of the event. This includes addressing human error or equipment failure that could result in an overpressure situation.

2. *Practice: An operator's DIMP plan should include the process used to identify performance issues that could involve a particular type of pressure regulator.*
   Description: The DIMP plan should include data collection and analysis that leads to identification of any performance issues for the makes/models of pressure regulators used in the system.

3. *Practice: In its DIMP plan, an operator should avoid using a probability of zero for low probability events and should consider their likelihood and consequence factors, or use Subject Matter Expert (SME) input.*
   Description: Events that have a low probability of occurring should not have a rating of zero in the risk ranking model used, unless supported by engineering analysis.

4. *Practice: In its DIMP plan, an operator should confirm the appropriate consequence factors are applied for low probability events, such as over-pressurization.*
   Description: Risk models used by operators should feature accurate potential consequence outcomes for those events that are tied to over-pressurization.

Glossary

Abnormal Operating Condition (AOC): A condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may (a) indicate a condition exceeding design limits; or (b) Result in a hazard(s) to persons, property, or the environment.

Bypass Valve: A valve used to control non-pressure regulated parallel piping runs within a pressure regulating station. A bypass valve allows for continuous gas flow if the regulating station is inoperable, taken out of service, or if additional gas flow is required downstream. Bypass piping is used to route gas around some part of a system or station (i.e. a regulator) to facilitate taking that part of the station out of service to be worked on.

Contaminant: Impurities including but not limited to rust, moisture, carbon dioxide, other liquids, debris, and sulfur compounds that are sometimes found in natural gas.

Control Line/Sensing Line (Control Piping): Piping that is connected to the regulator and downstream of the regulator. The control line increases or limits the flow of natural gas based on pressure measured downstream.

Control Point: A point in a gas system where pressure and/or flow is controlled. This may be a regulator station controlled by control lines connected to the downstream gas system, or controlled remotely from a Control Room.

Control Valve: Valves used to moderate and/or restrict the flow of natural gas. These valves can be actuated remotely, locally, or automatically by sensing pressure differentials.

Management of Change (MOC): Formal procedure used in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural, and organizational changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

MAOP: The maximum pressure at which a pipeline or segment of a pipeline may be operated.

Monitor Regulator (Monitoring Regulator): A pressure regulator installed in series with another pressure regulator that automatically assumes control of the pressure downstream of the station, in case that pressure exceeds a set maximum.

Primary Regulator (Worker Regulator): Pressure limiting and controlling device that reduces or limits the input pressure of gas to a desired set value at its output.

(Pressure) Relief Valve/Device: A pressure switch or unloading device that exhaust gas to atmosphere if pressure in pipe exceeds a set limit.

SCADA: Supervisory Control and Data Acquisition system is a computer-based system used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Sensor: The initial device in a telemetry system that measures or senses a physical parameter (pressure, temperature, flow) and converts that into an electronic signal. Sensors may be connected to a transmitting device sending signals to a SCADA system, or they may be connected to a local device that logs or stores the information for uploading at a later date.

Separation Valve: Valves used to isolate gas systems, which may be operating at similar or differing pressures.

Slam Shut Valve: Valves specifically designed to protect downstream equipment from either under or over pressure conditions by immediately shutting off gas supply downstream if it detects the pressure drops or exceeds the permissible limit.

Subject Matter Expert (SME): Subject Matter Expert is a person or group of people who are trained and have adequate experience in a specific topic area to be considered to have expertise on the subject matter.

Utilization Pressure: A lower pressure system that delivers gas at a minimum delivery pressure needed to operate appliances.

Vent line: Vent lines provide a way to exhaust gas from the components and equipment to atmosphere.

APPENDIX: The following is taken from AGA's Gas Engineering and Operations Practices (GEOP) Series: Distribution System Design, Revised 2004, Book D-1, Volume III. The full document can be purchased at https://www.aga.org/news/publications-store/

Chapter 13

REGULATOR STATION DESIGN

Gilbert A. Holmstoen, Mark D. Nelson

District regulator and city gate stations normally are required in a distribution system. They reduce the elevated pressures provided by a pipeline supplier to lower distribution system pressures. The city gate station, or town border station, receives gas at the supplier's elevated pressure and in turn serves individual customer meters and/or any district regulator stations at a lower pressure. The principles presented in this chapter can be applied to either type of station design. District regulator stations further reduce system pressures to levels beat suited to serve end-users.

CITY GATE STATIONS

A "city gate" or "town border" station is a multifunction station that usually includes pressure regulation, measurement, and odorization facilities. This is the transfer point between the pipeline supplier and the distribution utility. Normally, regulators are part of these stations because the pipeline supplier's system usually operates at a higher pressure than the utility company's system. At many stations, due to high pressure differentials, heaters are installed to warm the gas to compensate for the Joule-Thomson effect. In addition to regulation, the station usually includes metering facilities and equipment to measure the pressure and temperature of the gas and sometimes the specific gravity and heating value as well. Odorant injection commonly is performed at these stations. These stations usually are installed on private property owned by the supplier.

The flow metering and odorant injection requirements of a city gate station require special consideration by the design engineer, because they make this type of station different from the facilities normally encountered in a distribution system.

Flow metering is primarily the responsibility of the pipeline supplier, but distribution utilities monitor this measurement to verify billing, dispatch load as a means of remaining within daily contract volumes, and control odorant rejection. Although distributors sometimes install their own measurement facilities in or adjacent to the station, it is common practice for the distribution company to interface with the pipeline supplier's equipment rather than use separate metering facilities. In this way, the company and the supplier receive the same data on volume, inlet pressure, temperature, specific gravity, and heating value.

Odorization is usually the responsibility of the distribution utility. Although odorized gas may be received from the pipeline supplier, the level or type of odorant may not meet the needs of the distribution utility. Odorant should be injected at a point that will ensure good mixing at a rate proportional to gas flow. Special consideration should be given to the materials and assembly methods used in the odorant system to ensure compatibility with the odorant and to make the system as leak-proof as possible. More detailed information on gas ordorization can be obtained from the A.G.A. *Odorization Manual* and from the Institute of Gas Technology's most recent proceedings of its odorization symposia.[1, 2]

The engineer must be aware of any limitations to the flow rate at a gate station and design accordingly. The supplier may have a maximum flow limitation on its measurement equipment. The utility's operating system should not cause the system demand to exceed this limit because of the supplier's inability to measure the gas. Also, the utility must be able to react to a situation where no odorant is being injected into the flowing gas stream. By continuous monitoring, the utility can be appraised of this situation so that it can shut down the station, if feasible, until the problem is resolved. More detailed information on the selection and design of city gate station equipment is given in GEOP series Volume IV, "Measurement" and part of A.G.A Gas Measurement manual, "Design of Meter and Regulator Stations."

More than one supplier may serve a utility's distribution system through separate gate stations. In this situation, there may be targets set for the flow rate through one or more of the gate stations based on negotiated volume with each supplier. It may be necessary to design the regulators to function in a flow-control mode in addition to a pressure-control mode. Unlike a pressure control regulator, a flow control regulator responds to measured flow rate rather than to a measured downstream outlet pressure.

In distribution systems where flow control is used, pressure control regulation also must be used to pick up any variation in total system demand above the flow set point. The flow set point of a flow control regulator can be set higher than the total system demand. Therefore, a means of going into a pressure override mode must be considered in the design to prevent over-pressurization by the flow control regulator.

DISTRICT REGULATOR STATIONS

The district regulator station is a pressure-reducing facility that receives gas from a supply line and delivers it to a distribution system at a predetermined pressure and at a flow rate equal to (except for line pack) the demand on the system. Supply line pressures may vary from a few to hundreds of psig; controlled pressures in a distribution system usually vary from about 0.25 psig (1.7 kPa) to 100 psig (689 kPa). Distribution systems may be supplied by more than one district regulator station. Because of varying conditions and requirements, there are no standard designs that satisfy all situations. However, the following general requirements must be satisfied by all designs:

- **Performance**-The design must result in a district regulator station that will perform the function for which it was intended under all foreseeable operating conditions. Factors that will affect performance include proper sizing, equipment selection, piping layout, and sites selection.
- **Safety**-The design must provide protection against any possible damage or equipment failure that could result in overpressure and/or loss of supply to the distribution system.
- **Environmental**-The district regulator station should be designed to be aesthetically acceptable and free of objectionable noise and odour. The station must conform to all applicable codes and ordinances.
- **Economy**-The design must accomplish all of the above at the minimal overall project cost for initial installation and long-term maintenance.

DESIGN CRITERIA

The regulator station designer must determine the size of the installation in terms of performance, capacity, and equipment requirements. Factors to be considered are:

- Maximum and minimum flow requirements. Maximum flow usually occurs at minimum inlet pressure; minimum flow can occur at a variety of inlet pressures. Determination of maximum load can be developed from information such as:
  - ◊ Actual customer maximum hourly loads, including large commercial or industrial loads
  - ◊ Computerized network model
  - ◊ Capacity of the outlet main
  - ◊ Count of homes and heating customers

  Monthly sales data converted to maximum hour load
- Upstream and downstream MAOPs
- Future flow requirements. How much of the projected flow should be provided for the initial installation?
- Maximum and minimum pressures available in the supply line
- Number of stages of pressure reduction. If more than one stage is indicated, should the installation be a double cut or monitor design? How much distance is necessary between stages?
- Should parallel runs be provided or is a single run adequate? Are there other feeds into the distribution system? Would loss of this facility be critical to the system? If parallel runs are provided, should each be capable of supplying the system under maximum conditions? If a single run is adequate, should a bypass with or without a regulator be provided?
- Should a station bypass be provided? It is usually needed for single-run stations.

- Should heating be provided? If water or heavy hydrocarbon vapours are present in the gas and a large pressure reduction is required, the refrigeration effect may occasionally lower the gas temperature below its dew point with resulting hydrate formation. Low gas temperature also will freeze heavy, water-laden soil surrounding the outlet piping, causing heaving of foundations and road surfaces.
- Should the gas supply be odorized? Usually this is done at the city gate/town border station.
- Should noise control be provided in the design? Noise level restrictions in a residential area may influence equipment selection. Reduced noise trim on regulators, fences or below ground noise. Consideration should be given in design for noise protection to protect the general public and maintenance personnel. Vibration due to excessively high noise levels may cause instrument and mechanical failure. Special noise reduction regulator equipment should be considered when excessive noise levels are predicted by velocity calculations.
- Work space requirements. How much room is required for safe and efficient operation and maintenance?

SITE SELECTION

When general design requirements have been established, a suitable location can be selected. For a new system, the constraints on location may be quite flexible, for an existing system, the location is dictated by the whereabouts of the supply line and distribution system piping capable of carrying the required gas volume.

In rural or undeveloped areas, private land may be available for a nominal cost and, consequently, may be the choice for all except very small regulator stations. In urban areas where land is expensive and difficult to obtain, use of private land may need to be reserved for very large installations and/or those requiring above ground housing.

Installations requiring gas odorization or heating usually are located on private land. Installations on private land have the flexibility of being installed above ground in buildings, fenced, or unenclosed; alternatively, they may be installed in buried or partly buried vaults or pits. Pits usually are considered underground enclosures with manhole access, whereas vaults have steel or aluminium doors or removable covers through which access to the interior is gained. Covers should be designed so that they cannot accidentally close or fall into the vault or pit and damage the regulator equipment. Covers must be designed for anticipated vehicle loading.

Installations on public rights-of-way may be in buried vaults or pits if the water table and drainage permit; they also may be installed above ground without enclosures if protection from traffic and other damage is adequate and local authorities permit. (See Figure 142.)

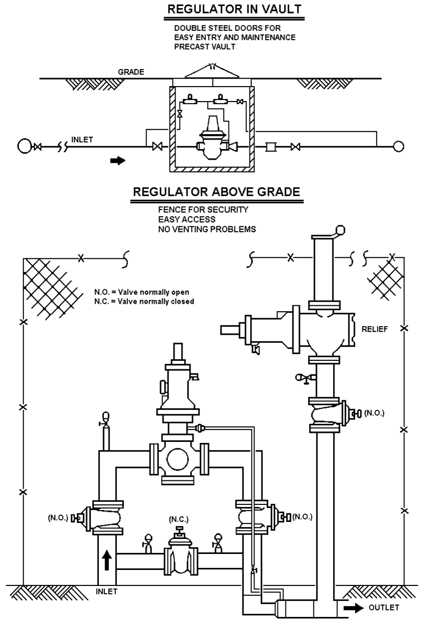

Figure 142. **Typical regulator installations - below grade *(top)* and above grade *(bottom)*.**

Acceptable screening for aesthetic reasons may also be necessary. Plastic strips can be threaded into chain link fences to screen station facilities from view, and, on occasion, above ground enclosures have been designed to blend with surrounding structures.

Preferably, vaults and pits should be located out of roadways if access will be a problem because of traffic congestion or parking. Underground enclosures constructed of concrete or steel under roadways in northern snow areas are subject to the adverse effects of salt used for snow and ice removal; equipment and piping particularly are prone to corrosion. Vaults should not be located at low elevations or near catch basins where they are exposed to flooding unless the equipment is capable of operating safely underwater. Sidewalk locations in high, dry sites are preferred. Access to electric power must also be provided if the installation includes electronic components. Ventilation of vaults should be provided in accordance with applicable codes.

Above ground facilities have the advantage of relatively easy accessibility, low maintenance, and low cost. They have the disadvantages of possible damage from traffic and/or vandalism and a greater probability of there being a noise problem. Since they usually must be installed on private property, they may also require land acquisition and possible rezoning.

REGULATOR SELECTION

The regulator is the heart of the regulator station and should be chosen with care from the wide variety of designs available. Basically, a regulator consists of a control valve that controls gas flow, a sensing element and a loading element. Refer to Chapter 11 for descriptions of the various types of regulators.

Factors that should be considered in selecting the type of regulator include:

- Outlet pressure droop characteristics and response
- The maximum and minimum pressure differential rating of the equipment
- Reliability of operation
- Ease of maintenance (in-line maintenance is advantageous)
- Cost of equipment
- Physical space limitations in vaults
- Noise characteristics

REGULATOR SIZING

Selection of the proper regulator size is an important element in achieving proper operation, minimal pressure droop, quiet operation, and minimum maintenance. The size should be based on the maximum load at the minimum inlet pressure at which the load occurs. If the demand varies widely, it may be advisable to install parallel runs, with the second run opening at a predetermined pressure drop to avoid the problem of a single large regulator's throttling near the closed position. A further advantage of installing parallel regulators is that the relief valve, if provided, is required to protect against the failure of only one regulator-whichever has the larger capacity. Excessive pressure droop under maximum conditions should be avoided.

NOISE CONTROL

Usually it will be prudent to include a noise analysis in the design work for the district regulator station. The regulator is usually the primary noise generator, but it is not the only one. High gas flow velocities, large pressure reductions, and abrupt changes in direction of flow - all creating turbulence generate noise. A control valve with a straight-through flow design, such as the "expandable sleeve" valve, is inherently less noisy than one with high turbulence. Regulator manufacturers provide design data on noise emissions for varying flow conditions.

Regulator valve cages, designed for noise control, are available. They dissipate acoustic energy by directing the gas through slots or small openings. Additional noise attenuation may be achieved by use of a silencer and/or a diffuser downstream of the regulator. Other methods of noise control include use of heavy wall pipes; sweep bends for directional changes; full open shutoff valves; buried piping; and sound absorbing material for wrapping exposed pipes. Enclosing a facility in a building designed for acoustical control is effective, but operating and maintenance personnel must be protected from excessive noise exposure while working within the building.

It is easier to control noise at the source by good design than it is to mask the noise after it is generated.

OVERPRESSURE PROTECTION

The modern gas regulator is a highly reliable device, but failures do occur due to physical damage, equipment failure, and the presence of foreign material in the gas stream.

Gas may contain moisture, dirt, sand and/or stones, welding slag, metal cuttings from tapping procedures, and other debris. Problems caused by such foreign material in the gas stream are most prevalent following construction on the line supplying gas to the district regulator station. Small pilot regulators and other restricting orifices should be protected from plugging by the installation of small gas filters upstream. Primary regulators are not as sensitive to small particles and may be protected from larger debris by the installation of strainers upstream from the regulators. Filters and strainers should be monitored closely, and a strict servicing schedule should be maintained.

Regulators with diaphragm actuators tend to fail in either the open or closed position on loss of loading pressure depending on whether the main spring is designed to open or close the valve. The designer of the district regulator station must make a choice based on the nature of the distribution system being supplied. A common practice is to use a fail-open primary regulator and a fail-closed monitor regulator. In the event of a single failure, two fail-closed regulators installed in parallel will provide continuity of service while reducing the probability of over pressurization. However, it should be remembered that when downstream-sensed pressure is lost, the regulator always would fail open whether the regulator design is "fail-open" or "fail-shut."

Protecting the distribution system from overpressure resulting from regulator failure may be accomplished by the use of several devices, the most common of which are relief valves, series regulators, and monitor regulators; occasionally automatic shutoff valves are used. These devices were discussed in Chapter 12. The above-grade regulator station shown in Figure 143 illustrates use of a relief valve for overpressure protection. They should not be used in urban areas unless gas can vent safely without the likelihood of entering nearby buildings. Though it is not shown in Figure 142, some provision for overpressure protection must be associated with the regulator in the vault station.

Figure 143 shows a typical underground station layout with monitor protection. Figure 144 shows a typical above ground layout with relief protection.

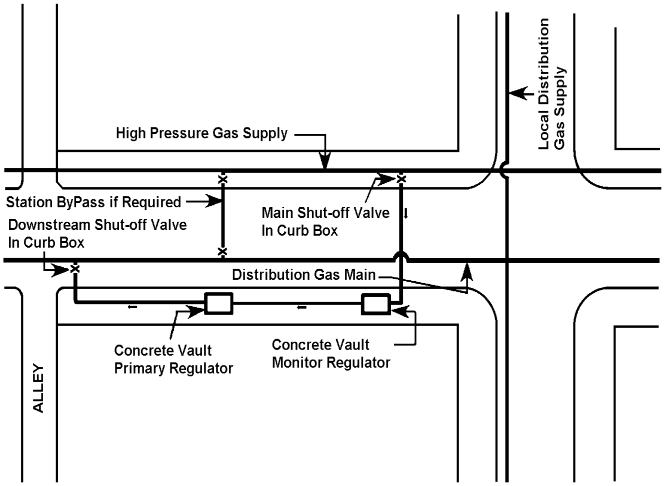

Figure 143. **Typical underground regulator station.**

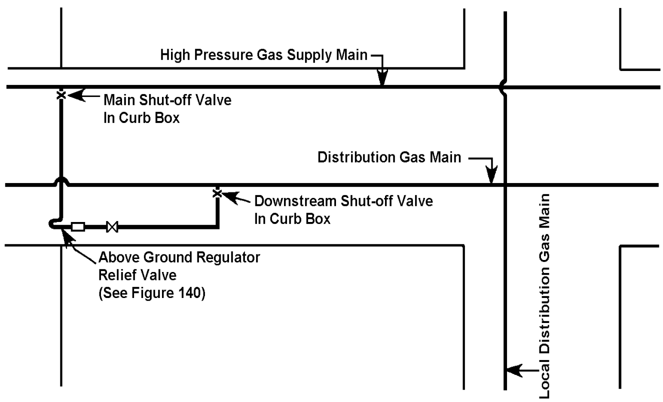

Figure 144. **Typical above ground regulator station.**

It should be noted that monitor protection may also be installed above ground in suitable locations, and relief protection may also be installed underground. However, the relief stack must be located so that the gas can be blown to the atmosphere without hazard. Many companies' standards are 6.5 ft to 7 ft (1.98 m to 2.13 m) above grade.

The conditions that will be created when an overpressure-protection device operates must be considered when the type of device is being selected. Table 77 presents the various scenarios that occur when various types of overpressure-protection devices are activated.

It is important that the failure of a regulator be signalled immediately to operating personnel. Telemetered pressure data taken near the regulator outlet will provide this information effectively. Recording charts at the district regulator station do not reveal their data until a scheduled chart change is made. Blowing relief valves in a populated area are usually reported by the public.

PIPING AND VALVES

Although regulator installations in vaults or buildings often are standardized within distribution companies, the piping to and from the installation is controlled by local conditions and varies accordingly. Figures 144 and 145 are examples of piping configurations to and from district regulator stations. Low pressure systems typically are older and usually are found in urban areas. Piping and equipment are large, and district regulator stations require considerable space. Higher-pressure systems are usually newer and located in newer areas. Piping and equipment usually are smaller for equivalent flows, and regulator stations may be more compact and require less space. District regulator stations should have a station inlet valve and a station outlet valve; the latter can prevent back feeding in case emergency shutoff is required and is helpful for maintenance purposes.

Both valves should be separated from the regulator by a distance sufficient to permit isolating the station in case of an emergency such as a fire. Separation distances vary from 25 ft to 50 ft (7.6 m to 15 m) but can be greater. If the distribution system requires a feed at the district regulator station, a station bypass should be installed unless a pair of regulators in parallel is used. The bypass valve by code requirements is locked in a closed position to prevent accidental opening. If installed underground with a curb-box access, it should be identified in such a manner that improper opening, resulting in downstream overpressure, will not occur. If the bypass is used as a temporary manned feed, a means to monitor downstream pressure is required. The operator should consider the use of written procedures to ensure bypass and other station valves are operated correctly.

TABLE 77
Comparison of Overpressure-Protection Devices

Condition with Device Activated	**Relief**	**Working Monitor**	**Monitor**	**Series Regulation**	**Shut Off**	**Relief Monitor**
Customer remains on	Yes	Yes	Yes	Yes	No	Yes
Gas vented to atmosphere	Yes	No	No	No	No	Minor
Manual resetting required	No	No	No	No	Yes	No
Regulator capacity reduced	No	Yes	Yes	Yes	No	No
Immediate action by gas company required?	Yes	No	No	No	Yes	Maybe
Condition during Normal Operation						
Activated	No	Yes	No	Yes	No	No

The selection of shutoff valves is important in the design of the district regulator station. Valves must be accessible and operable under emergency conditions. Valve types available are plug valves (lubricated and non-lubricated), gate valves (rising and non-rising stem), and ball valves. Plug valves usually have restricted ports, which may be a factor at high flow rates in lower pressure applications. The lubricated plug may require lubrication before it can be operated and/or shut off tightly.

Over lubrication, which admits grease into the gas stream, should be avoided. Plug valves provide good throttling capabilities due to their internal design and are recommended for bypass and blow off applications. Gate valves usually have full-open bore. When installed underground, they should have a non-rising stem to avoid exposing threads to dirt and moisture in the open position. Gate valves normally operate easily without maintenance, although some have been susceptible to stem leaks through the packing gland and to the collection of foreign material in the bottom seating area. Ball valves are available with either full-opening or restricted ports; they are easy to operate and provide good shutoff if proper seat materials are used. Due to lack of lubrication requirements and small pressure drops, the ball or gate valves are best located between regulators and meters.

When vaults are used, the designer of the district regulator station should consider the effect of a single incident-such as an explosion-that could result in system overpressure due to the failure of both the regulator and the overpressure device. To prevent such an occurrence, there should be adequate separation between the regulator and the protection device.

Piping and control lines shall be located so as to minimize accidental damage. Piping and control lines in pits and vaults should be protected against atmospheric corrosion; tubing should be stainless steel.

INLET, OUTLET, BYPASS, AND CONTROL PIPING DESIGN

Proper pipe size selection, piping and fitting configuration, and control-line location are important to obtaining optimum performance from a district regulator installation. Inlet and outlet piping should be sized for maximum flow conditions, with velocity considered for noise control. Anticipated future load also should be considered. Selection of gradually tapered expanders and long-radius bends helps reduce turbulence, noise, vibration, and pressure loss.

Bypass piping should be sized in accordance with the required station capacity, and the manual throttle valve should be within sight of a connection for an outlet pressure gage.

Pressure-sensing control piping taps should be located downstream in the larger sized outlet piping. The pressure-sensing tap location must be located at a sufficient distance downstream from valves, tees, ells, or other fittings to minimize turbulence in the gas stream; eight to ten pipe diameters is recommended as a minimum. McGuire gives examples of several different regulator station designs.[3]

EXAMPLE

The following is a simplified exercise in sizing components for a district regulator station:

Load requirement	100 Mft^3/h (2.83×10^3 m^3/h)
MAOP of supply line	60 psig (414 kPa)
Minimum pressure in the supply line	30 psig (207 kPa)
MAOP of distribution system	10 psig (69 kPa)

Use the above ground regulator and relief valve configuration shown in Figure 142 and the regulator station layout shown in Figure 144 and the following assumptions:

3 in. (76 mm)	inlet piping
4 in. (101 mm)	outlet piping
2 in. (51 mm)	regulator
3 in. (76 mm)	relief valve
2 in. (51 mm)	by pass

Pipe and fittings from the supply line to the regulator include the following in equivalent length of 3 in. (76 mm) pipe:

1	3 in. (76 mm) gate valve	2 ft (0.6 m)
3	3 in. (76 mm) 90° long-radius weld ells	12 ft (3.7 m)
1	3 in. × 2 in. (76 mm × 51 mm) weld tee (run)	5 ft (1.5 m)
1	3 in. (76 mm) plug valve	12 ft (3.7 m)
1	3 in. × 2 in. (76 mm × 51 mm) weld reducer	5 ft (1.5 m)
	3 in. (76 mm) pipe	65 ft (19.8 m)
	Total 3 in. (76 mm) pipe equivalent	101 ft (30.8 m)

The capacity of the regulator can be obtained from manufacturers in the form of formulas, tables, nomographs, or PC software.

Calculation of the pressure drop for 100 Mft^3/h (2.83×10^3 m^3/h) flow with 30 psig (207 kPa) inlet and 101 ft (30.8 m) of 3 in. (76 mm) pipe gives 4.4 psi (30 kPa) using the Weymouth equation. Minimum pressure at the regulator now is 30 - 4.4 = 25.6 psig (177 kPa). The 2 in. (51 mm) regulator with 1¾ in. (45 mm) double-ported body is rated at 104 Mft^3/h (2.95×10^3 m^3/h) at 25 psig (172 kPa) inlet. Thus, the regulator is adequate.

A similar pressure drop determination for the 2 in. (51 mm) bypass will show that it also is adequate.

The relief valve must be sized for regulator failure under maximum pressure conditions. The allowable pressure increase, as per 192.201, for this 10 psig (69 kPa) system is 5 psi (34.5 kPa) (MAOP plus 50%). At a 12 psig (83 kPa) relief setting, the relief valve will relieve 130

Mft^3/h (3.68×10^3 m^3/h) with less than a 3 psi (21 kPa) increase over set point. At an inlet pressure of 60 psig (414 kPa), the failed regulator will pass about 700 Mft^3/h (1.98×10^4 m^3/h). The 3 in. (76 mm) relief valve is not adequate.

A 4 in. (102 mm) relief valve at the same relief setting will relieve 235 Mft^3/h (6.65×10^3 m^3/h) - the 4 in (102 mm) relief valve is adequate. We should install a 2 in. x 4 in. (51 mm × 102 mm) weld expander at the regulator outlet and a 4 in. (102 mm) full-open gate valve (locked open) ahead of the 4 in. (102 mm) relief valve. The relief valve should be installed downstream of the bypass and downstream of the regulator sensor line tap.

The outlet piping includes the following in equivalent length of 4-in. pipe:

1	2 in. × 4 in. (51 mm × 102 mm) weld expander	8 ft (2.4 m)
1	4 in. (102 mm) weld tee (branch)	6 ft (1.8 m)
1	4 in. × 2 in. (102 mm × 51mm) weld tee (run)	7 ft (2.1 m)
2	4 in. (102 mm) weld ells	10 ft (3.0 m)
1	4 in. (102 mm) gate valve	2 ft (0.6 m)
	4 in. (102 mm) pipe	20 ft (6.1 m)
	Total 4 in. (102 mm) pipe equivalent	63 ft (19 m)

The pressure drop for 100 Mft^3/h (2.83×10^3 m^3/h) flow with 10 psig (69 kPa) inlet and 100 ft (30.5 m) of 4 in. (102 mm) pipe is 1.1 psi (7.6 kPa). This leaves 8.9 psig (61 kPa) delivery pressure into the distribution main at maximum flow. In this example, it would be advisable to run the regulator's downstream control line directly to the distribution main to eliminate the effect of the pressure drop through the outlet piping.

Although the 4 in. (102 mm) piping immediately downstream of the regulator is adequate in terms of velocity up to 4 in. (102 mm) gate valve downstream of the regulator, the piping downstream of the 4 in. (102 mm) gate valve needs to be increased to a larger size in order to reduce the velocity and the associated pressure drop to the distribution main. This outlet header piping should be at least as large as the distribution main to which the station is being connected. At the A.G.A System Capacity Design Best Practices Roundtable held in September 1997, the general consensus was that the velocity in outlet header piping should be less than 65 ft/s (20 m/s). Solving the velocity equation given for pipe size results in a required internal diameter of 6.835 in. (173.6 mm). This would require an 8 in. (204 mm) pipe (either plastic with an underground transition or steel) to achieve a velocity lower than 65 ft/s (20 m/s).

$$\mathrm{ID\ (in.)} = \sqrt{\frac{750 \times Q\,(\mathrm{Mft^3/h})}{P\,(\mathrm{psia}) \times V\,(\mathrm{ft/s})}}$$

$$\mathrm{ID} = \sqrt{\frac{750 \times 100}{24.7 \times 65}} = 6.835 \text{ in. } (173 \text{ mm})$$

Section 9.5 of A.G.A. Gas Measurement Manual Part No. 9, 1988 is another good reference for valves and piping configurations.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND GAS	**)**	
RATES PURSUANT TO	**)**	**DOCKET NO. UD-18-07**
COUNCIL RESOLUTIONS R-15-194 AND	**)**	
R-17-504 AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

RAIFORD L. SMITH

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Raiford L. Smith. My business address is 10055 Grogans Mill Road, Suite 300, The Woodlands, Texas 77380.

Q2. DID YOU FILE REVISED DIRECT TESTIMONY IN THIS PROCEEDING IN SEPTEMBER 2018?

A. Yes.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am filing this Rebuttal Testimony before the Council of the City of New Orleans (the "Council") on behalf of Entergy New Orleans, LLC ("ENO").

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to Advisors witness Byron S. Watson's recommendation to (1) reject the Company's proposed Fixed Bill Option (Schedule FBO), and (2) treat pre-pay balances as rate base credits in future base rate action filings.

II. FIXED BILL OPTION

Q5. WHAT REASONS DID ADVISORS WITNESS WATSON CITE IN SUPPORT OF HIS RECOMMENDATION THAT THE COUNCIL REJECT THE COMPANY'S PROPOSED FIXED BILL OPTION?

A. Mr. Watson states in his Direct Testimony that he is concerned about the cost of the premium paid by fixed bill participants relative to the benefits they would enjoy under the program (particularly if those participants are low- or fixed-income customers), and that a similar option already exists in the form of the Company's levelized billing options.[1]

Q6. HOW DO YOU RESPOND TO MR. WATSON'S CONCERNS?

A. While I disagree that the reasons given should be cause for concern or the rejection of the proposed Schedule FBO, ENO is nonetheless receptive to the Advisors' feedback related to Schedule FBO. As such, ENO is willing to withdraw the proposed Schedule FBO from consideration for approval in this proceeding.

III. PRE-PAY

Q7. DO YOU HAVE ANY COMMENTS ABOUT MR. WATSON'S RECOMMENDATION THAT ENO TREAT PRE-PAY BALANCES AS RATE CREDITS IN FUTURE BASE RATE ACTION FILINGS?[2]

A. Because Mr. Watson's recommendation relates to future base rate action filings, I believe it would be more appropriate to make a determination on the merits of his recommendation during the adjudication of those future filings. As such, I do not have any further comments on the merits of his proposal at this time.

[1] Direct Testimony of Byron S. Watson on behalf of the Advisors to the Council of the City of New Orleans, Council Docket No. UD-18-07, February 2019 ("Watson Direct") at 70-71.

[2] Watson Direct at 68-69.

IV. CONCLUSION

Q8. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF Texas

COUNTY/PARISH OF Montgomery

NOW BEFORE ME, the undersigned authority, personally came and appeared,

RAIFORD L. SMITH,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

RAIFORD L. SMITH

Sworn to and

Subscribed Before Me

This 12 Day of March, 2019

NOTARY PUBLIC

LISA GATEWOOD
Notary Public, State of Texas
Comm. Expires 07-08-2020
Notary ID 3618776

NOTARY PUBLIC STATE OF TEXAS

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	**DOCKET NO. UD-18-07**
GAS RATES PURSUANT TO COUNCIL	**)**	
RESOLUTION R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

DONALD J. CLAYTON

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Donald J. Clayton. My business address is 201 King of Prussia Road, Suite 650, Radnor, PA 19087.

Q2. ARE YOU THE SAME DONALD J. CLAYTON WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony in this proceeding is to explain why Lane Kollen's recommendations with respect to service life and net salvage related to the Union Power Block and the amortization period for the general plant deficiency should be rejected by the Council of the City of New Orleans ("Council").

II. SERVICE LIFE FOR UNION POWER BLOCK

Q4. DO YOU AGREE WITH MR. KOLLEN THAT THE SERVICE LIFE FOR THE UNION POWER BLOCK SHOULD BE RAISED FROM 30 YEARS TO 40 YEARS?

A. No, for four basic reasons. First, the Energy Information Administration ("EIA") data that Mr. Kollen relies on to support his recommendation of a 40-year service life reflects the life span of the referenced power stations but does not reflect the average age of the dollars that have been spent at each station. In other words, Mr. Kollen identifies the length of time that the oldest individual items of plant have been in service but does not reflect the life of any of the investments related to the items of plant that have been made subsequent to the initial in-service date. Since depreciation reflects the capital recovery of the investment in *all* of the plant items, the ages of all of the plant items to be recovered through deprecation must be used in developing appropriate depreciation rates. Using the EIA data as the basis for depreciation rates (*i.e.*, using the overall life span as the average service life) produces a bias toward lives that are too long for depreciation purposes. Even though a generating station may be in service beyond 30 years, it is often the case that the average age of the investment in the station will be below 30 years.

Q5. CAN YOU PROVIDE A SIMPLE EXAMPLE ILLUSTRATING THIS POINT?

A. Yes. For example, if we assume a 40-year life span for Union Power Block and annual additions subsequent to the initial in-service date equal to a very conservative 2.5% of the initial investment, the average life of the overall investment would be 30 years and not 40 years as proposed by Mr. Kollen.

Q6. WHAT ARE THE THREE OTHER REASONS YOU DISAGREE WITH MR. KOLLEN'S SERVICE LIFE RECOMMENDATION?

A. Second, the Union Power Block was not originally constructed or operated by Entergy or another utility. As explained in the Rebuttal Testimony of Company witness Robert A. Breedlove, the Union Power Block, as a more modern, large frame machine, was constructed to achieve greater thermal efficiencies and output as compared to older combustion turbine and combine-cycle plants. These design features have required trade-offs in design margin, which impact the plant's useful/service life.[1] As such, the life of the plant is expected to be somewhat less than plants constructed by Entergy or other investor-owned electric companies.

Third, a 30-year average service life is within the range of lives used by other generators for facilities similar to the Union Power Block. Entergy Mississippi, LLC ("EML") has used a 30-year life for its Hinds and Atalla power plants, which are very similar to the Union Power Block. In addition, a compilation of deprecation statistics based on information reported in FERC Form 1 (see Exhibit DJC-5) shows that other companies use 30-year lives for similar plants. For example, Ameren has service lives of 30 years for its Joppa and Grand Tower Stations (see DJC-5 pp.12 and 13). Indianapolis Power and Light actually uses a 25-year life for its Eagle Valley Station (see DJC-5 p. 77), which is a large combined cycle facility built in 2002 and is similar to the Union Power Block.

[1] See Rebuttal Testimony of Robert A. Breedlove, Council Docket No. UD-18-07 (March 2019), p.4.

Fourth, without the expenditure of significant additional capital, it is unlikely that the Union Power Block could operate beyond 30 years. As explained by Mr. Breedlove, within the first 30 years of operation, several major and costly refurbishments are required to keep such a station in service and these investments will have lives far shorter than 30 years.

Q7. WHAT ARE THE IMPACTS ON RATEPAYERS IF THE SERVICE LIFE FOR UNION POWER BLOCK IS SET TOO LONG?

A. If the initial service life is set too long, future customers will have to make up capital recovery shortfalls over shorter and shorter timeframes. In extreme cases, customers who never benefited from the output of the plant will have to pay for a portion of the plant's cost. Also, if the life is set too long, the total revenue requirement over the life of the asset will be higher than it should be because the average rate base over the life of the asset will be higher than it would be if the proper life is used.

III. NET SALVAGE FOR UNION POWER BLOCK

Q8. DO YOU AGREE WITH MR. KOLLEN THAT 0% NET SALVAGE SHOULD BE USED FOR UNION POWER BLOCK INSTEAD OF THE -8% YOU HAVE RECOMMENDED?

A. No. It is unreasonable to assume that there will be no cost of removal associated with the Union Power Block when it is ultimately taken out of service. Based on my analysis of historical retirements for other similar Entergy combined cycle gas turbines ("CCGT") stations, it is clear that the cost of removal will exceed the gross salvage value of the retired equipment and -8% is well within the range used by other electric companies.

Q9. WHAT NET SALVAGE ESTIMATES ARE BEING USED BY OTHER ENTERGY OPERATING COMPANIES FOR SIMILAR PLANTS?

A. For CCGTs, Entergy Arkansas, LLC and EML are currently using -10%. In Entergy Louisiana, LLC's most recent depreciation study, -8% net salvage for other production was estimated (it should be noted that the Entergy Louisiana, LLC estimate includes the Union Power Blocks 3 and 4, which are identical to Power Block 1). In the most recent study for EML, which has not yet been approved by the Mississippi Public Service Commission, -7% was estimated for the Attala station and -10% was estimated for the Hinds station.

Q10. IS IT APPROPRIATE TO USE ANALYSES OF INTERIM RETIREMENTS AS THE BASIS FOR NET SALVAGE ESTIMATES?

A. Yes. In those cases where studies of final dismantlement costs are not available, it is appropriate to use gross salvage and cost of removal related to interim retirements as an input to the net salvage estimate.

Q11. WERE ANY OF THE NET SALVAGE ESTIMATES REFERENCED ABOVE BASED ON DETAILED DISMANTLEMENT STUDIES?

A. Yes. EML has recently commissioned dismantlement studies by Sargent and Lundy for its Attala and Hinds stations, which are similar to the Union Power Block. The estimates for the Attala and Hinds stations include analysis of both interim retirements and the final dismantlement cost estimated by Sargent and Lundy.

Q12. WHAT NET SALVAGE ESTIMATES ARE USED FOR OTHER PRODUCTION BY OTHER ELECTRIC COMPANIES?

A. As shown in Exhibit DJC-5, many other electric companies use non-zero estimates of net salvage for combustion turbines ("CTs") and CCGTs included in other production. The estimates range from 0% to -25% with estimates in the -5% to -10% range occurring frequently.

Q13. WHY IS IT APPROPRIATE TO INCLUDE NET NEGATIVE SALVAGE IN THE DEPRECIATION RATE?

A. It is appropriate to include net negative salvage (or net cost of removal) in the deprecation rate so that customers who benefit from the use of the asset during its service life pay the total cost of the asset, including its ultimate disposition cost. If net cost of removal is not included in the deprecation rate, customers who have never benefited from the use of the asset will end up paying for the ultimate disposal of the asset.

Q14. ARE RATEPAYERS HARMED IF THE COMPANY DELAYS DISMANTLEMENT AFTER A STATION HAS BEEN REMOVED FROM SERVICE?

A. No. If negative net salvage is included in the deprecation rate over the life of the assets, ratepayers will continue to benefit from a credit to rate base for the amount of net negative salvage collected until dismantlement actually occurs.

Q15. DO YOU AGREE WITH MR. KOLLEN THAT A LACK OF SALVAGE AND COST OF REMOVAL HISTORY SUPPORTS THE NOTION THAT THE NET SALVAGE RATE SHOULD BE SET TO 0%?

A. No. This is a specious argument. Given Mr. Kollen's logic, it would never be possible to make a non-zero net salvage estimate for newly acquired property. Simply because something is new and lacks a history should not preclude a depreciation professional from making non-zero net salvage estimates. Typically in deprecation studies net salvage percentages for new property are based on historical indications for similar types of property either inside or outside of the company under study.

IV. AMORTIZATION OF GENERAL PLANT RESERVE DEFICIENCY

Q16. DO YOU AGREE WITH MR. KOLLEN THAT THE AMORTIZATION PERIOD FOR THE GENERAL PLANT DEPRECIATION RESERVE DEFICIENCY

SHOULD BE SET AT 20 YEARS INSTEAD OF THE 10YEAR PERIOD PROPOSED BY THE COMPANY?

A. No. Under the remaining life methodology, reserve deficiencies are trued up over a period equal to the average remaining life of the underlying depreciable group. For general plant other than structures and improvements, the average remaining life is 5.9 years. The company has already proposed to extend the amortization period to 10 years to lessen the impact on customers. To go to a 20-year amortization is simply not justified and delays recovery beyond a reasonable period.

V. CONCLUSION

Q17. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR REVIEW OF MR. KOLLEN'S TESTIMONY.

A. The Council should reject Mr. Kollen's recommendations and adopt the Company's recommendations with respect to the average service life and net salvage percent for the Union Power Block and amortization of the general plant reserve deficiency.

Q18. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

AFFIDAVIT

STATE OF COMMONWEALTH OF PENNSYLVANIA

COUNTY/PARISH OF COUNTY OF ALLEGHENY

NOW BEFORE ME, the undersigned authority, personally came and appeared,

DONALD J. CLAYTON,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

DONALD J. CLAYTON

Sworn to and

Subscribed Before Me

This 12th Day of March, 2019

NOTARY PUBLIC

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Harry M. Ruben, Notary Public
Pine Twp., AlleghenyCounty
My Commission Expires July 13, 2020
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

AFFIDAVIT

STATE OF COMMONWEALTH OF PENNSYLVANIA

COUNTY/PARISH OF COUNTY OF ALLEGHENY

NOW BEFORE ME, the undersigned authority, personally came and appeared,

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MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTION R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

EXHIBIT DJC-5

SEE ATTACHED CD

MARCH 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	**DOCKET NO. UD-18-07**
GAS RATES PURSUANT TO COUNCIL	**)**	
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

ROBERT A. BREEDLOVE

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Robert A. Breedlove. My business address is 10055 Grogan's Mill Road, The Woodlands, Texas 77380.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, LLC[1] as Director of Fleet Maintenance in Power Generation. In that capacity, I am responsible for providing technical oversight and outage planning and execution for Entergy's fleet of generating units.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony before the Council of the City of New Orleans ("the Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 1996, I earned a Bachelor of Science degree in Mechanical Engineering from Mississippi State University. In 2008, I was awarded a Master of Business Administration degree from Tulane University.

[1] On September 30, 2018, Entergy Services, Inc. converted to a Louisiana limited liability company from a Delaware corporation and is now Entergy Services, LLC ("ESL"). ESL is a service company subsidiary of Entergy Corporation that provides technical and administrative services to Entergy affiliates, including Entergy New Orleans, LLC.

Between 1996 and 2000, I was employed by a major U.S.-based petrochemical company in a project engineering role for development of electric power and utilities projects throughout the company's facilities worldwide. In 2000, I joined Entergy Gulf States (one of the predecessors to Entergy Services, LLC) as a Plant Engineer at one of our gas turbine generating plants. From 2004 through 2010, I served as Process Superintendent and later Production Superintendent for several plants at the Entergy Operating Companies, including three gas turbine-powered plants in northern Louisiana. In 2010, I was named asset manager for Entergy Louisiana, LLC's ("ELL's") Acadia Power Block Two gas turbine combined-cycle unit. In 2012, I was named Fleet Maintenance Manager with responsibility for managing strategic initiatives for Entergy's fleet of gas turbine combined-cycle plants. In 2016, I was named Director of Plant Support with responsibility for technical training, water chemistry, operational excellence programs, and North American Electric Reliability Corporation standards compliance for the power generation fleet. In 2018, I moved into the Director of Fleet Maintenance role.

Q5. HAVE YOU PREVIOUSLY TESTIFIED IN UTILITY REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Louisiana Public Service Commission in Docket No. U-33770. I also testified before the Council in Docket No. UD-16-02.

II. PURPOSE OF TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to refute the recommendation contained in the Direct Testimony of Mr. Lane Kollen on behalf of the Crescent City Power Users Group regarding the depreciation rate and service life of Union Power Block 1 ("Union PB1"). Specifically, I demonstrate that a 30-year service life for Union PB1 is reasonable and supports the recommendation of Company witness Donald J. Clayton.

III. UNION POWER BLOCK 1

Q7. PLEASE DESCRIBE UNION PB1.

A. Union PB1 is a natural gas-fired combined-cycle gas turbine ("CCGT") unit located at the Union Power Station ("UPS") in El Dorado, Arkansas. UPS began full commercial operation in July 2003. It was originally constructed, owned, and operated through a joint venture between TECO Power Systems and Panda Energy. At the time it was built, UPS was the largest independent power plant in the United States, and it had been used exclusively as a merchant power plant since the beginning of its commercial operations (*i.e.*, it has been used only to make sales in the competitive wholesale market at unregulated rates) until its purchase by ENO, Entergy Arkansas, LLC and Entergy Louisiana, LLC.

UPS is comprised of four power blocks (designated PB1, PB2, PB3, and PB4), each of which has a nominal rating of 538 MW and a summer rating of 495 MW. UPS consists of eight General Electric Company ("GE") Frame 7241FA combustion turbines ("CTs"), eight Alstom Power Inc. heat recovery steam generators ("HRSGs"), and four GE D-11 condensing steam turbines ("STs") in an outdoor arrangement. The equipment is configured in four 2 x 1 power blocks (two CT/HRSG trains each and one ST each).

Q8. PLEASE DESCRIBE THE TYPE OF MACHINES THAT COMPRISE UNION PB1 RELATIVE TO WHAT IS CURRENTLY USED IN THE INDUSTRY.

A. Union PB1 is a modern, large-frame combustion turbine-based combined-cycle power plant. The GE 7241FA CTs and similar turbines by other manufacturers that have been introduced into the industry over the last 20 years are referred to collectively as modern, large frame combustion turbines, meaning that they are designed to operate at higher thermal efficiencies and output compared to older combustion turbine and combined-cycle power plants. As CCGT technology has advanced and thermal efficiency has increased, it has come at the cost of equipment being designed with reduced margins when compared to older technologies. Examples include thinner materials (boiler tubes, turbine blades, turbine shells and casings, *etc.*) and operation at higher temperatures.

Importantly, these design features which allow the plant to operate at a higher thermal efficiency have required trade-offs in design margin, which impact the plant's useful/service life. For this reason, it is problematic to compare modern (2000 to present) combined-cycle plants to older technologies, such as legacy boiler/steam turbine plants and even early-generation combined-cycle plants. As such, these factors should be taken into account when estimating the service life of an individual CCGT plant.

Q9. WHAT ADDITIONAL CONSIDERATIONS SHOULD BE TAKEN INTO ACCOUNT REGARDING THE SERVICE LIFE OF A COMBINED-CYCLE TURBINE PLANT?

A. When evaluating the design for a plant, the useful life for the major components of the plant must be considered. When major components in the plant (such as combustion turbine rotors, generators, turbine casings/shells, major sections of boiler equipment) have reached the end of their individual serviceable life, decisions must be made regarding whether it is economically feasible to replace these components to allow the plant to continue to operate. Although the unit may be able to continue operation with the introduction of major capital investment to replace these major components, doing so will carry the plant's life beyond the original intended life of the major components and would represent a life extension project for the plant instead of being considered part of the plant's original useful life. For example, the combustion turbine rotors have a design life of approximately 144,000 operating hours (about 19 years averaging 7,400 operating hours per year). After this point, a decision must be made whether to replace the rotors at a cost of approximately $30 million to $40 million per CCGT power block (2018 cost basis) in conjunction with considering the remaining life and replacement cost of the other major components in the plant, ongoing maintenance costs associated with other components, and then-existing resource alternatives.

IV. RESPONSE TO MR. KOLLEN'S CLAIMS

Q10. WHAT ARE MR. KOLLEN'S CLAIMS WITH RESPECT TO THE SERVICE LIFE OF UNION PB1?

A. Mr. Kollen claims that the Company's recommended 30-year service life is "excessively short" and that a 40-year service life should be used for Union PB1.

Q11. WHAT IS THE PURPORTED BASIS FOR MR. KOLLEN'S CLAIM THAT A 30-YEAR SERVICE LIFE FOR UNION PB1 IS UNREASONABLE?

A. Mr. Kollen points to certain data reported by the Energy Information Administration ("EIA"), *i.e.*, Energy Information Administration November 2018 Form EIA-860M ("Form EIA-860M").[2] In particular, Mr. Kollen indicates that the data reported by EIA shows "there are combined cycle units that were in service for 40 to 50 years before their retirements,"[3] … "and combined cycle units that have been in operation for 40 to 50 years and still remain in operation." [4]

Q12. DO YOU AGREE WITH MR. KOLLEN'S CONCLUSION THAT THE PROPOSED SERVICE LIFE FOR UNION PB1 IS EXCESSIVELY SHORT?

A. Absolutely not, for several reasons. First, there is insufficient operational data for CCGT of the vintage of Union PB1 to conclude that these units can operate beyond 30 years

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[2] Direct Testimony and Exhibits of Lane Kollen on behalf of Crescent City Power Users' Group, Council Docket No. UD-18-07 (February 2019) ("Kollen Testimony"), p. 29. Exhibit RAB-1 attached to my testimony is an excerpt from the November 2018 Form EIA-860M ("https://www.eia.gov/electricity/data/eia860m/").

[3] *See*, Exhibit RAB-1, p.1.

[4] Kollen Testimony at 29.; *see*, Exhibit RAB-1, p.2.

without extending the initial service life by introduction of substantial capital investment. Also, according to the Electric Power Research Institute, "[t]ypical design lives of fossil-fuel plants are in the range of 25 years or 200,000 operating hours, but many **can be extended** to more than 40 years **with increased investment**. Many individual component parts have significantly shorter design lives." (emphasis added).[5] Third, the statistics provided in the EIA data relied on by Mr. Kollen must be considered in light of the differences in the technology that I described earlier in my testimony. It is inappropriate to focus solely on these statistics to support a reasonable estimate of the useful/service life for Union PB1.

Q13. PLEASE EXPLAIN FURTHER WHY IT IS INAPPROPRIATE TO RELY SOLELY UPON FORM EIA-860M DATA AS A BASIS FOR PROVIDING A RELIABLE ESTIMATE OF THE EXPECTED USEFUL LIFE OF UNION PB1.

A. First, I would caution against strict reliance on statistical information reported by EIA because of, among other things, differences in CCGT technology. Mr. Kollen points out in his testimony that the service lives for combined-cycle units "may be 40 years or more" when reviewing actual service lives reported by the EIA. However, a closer review of the EIA data relied upon by Mr. Kollen reveals that the average useful life of all currently-retired combined-cycle units listed in the EIA database is 26.8 years – significantly less than the 40 years suggested by Mr. Kollen. Analysis of the combined-cycle units that have

[5] See Exhibit RAB-2, Excerpt from Electric Power Research Institute Technical Report "Strategies for Maintaining Fossil Assets Designated for Retirement," (2012) at 3-6.

been retired with a useful life at or longer than the 40 years suggested by Mr. Kollen indicates that such units are significantly different in technology than the Union PB1 plant as judged by the size of the plant, which has significantly increased as newer technologies have been introduced into the industry. For example, the average size of the retired combined-cycle plant population is less than 50 MW, whereas the Union PB1 plant has a nominal rating of 538 MW.

Of the population of retired units from the EIA database that achieved a useful life of 30 years or longer,[6] perhaps the plant that is most similar to Union PB1 is Calpine's Clear Lake Cogeneration plant in Pasadena, Texas. This unit was placed in service in 1985 and used Westinghouse 501D5 combustion turbine technology, which represented one of the most modern combustion turbine technologies at the time, but has since been surpassed by more modern technologies such as the GE 7241FA combustion turbines for Union PB1. According to the EIA data provided by Mr. Kollen, the Clear Lake plant was retired in 2017 after a 31-year serviceable life. At the time the plant was retired, Calpine announced that the plant was being retired because "[t]he 31-year-old Clear Lake plant, a natural gas-fired plant with a generation capacity of 400 megawatts, has **outdated technology**, **growing maintenance costs** and shrinking profits" (emphasis added).[7]

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[6] Exhibit RAB-1, p.2.
[7] https://fuelfix.com/blog/2016/07/29/calpine-plans-to-close-cleark-lake-power-plant/.

Q14. IS THERE ANOTHER EXAMPLE THAT DEMONSTRATES MR. KOLLEN'S RELIANCE SOLELY UPON THE STATICS SET FORTH IN THE EIA DATA IS INAPPROPRIATE?

A. Yes. Mr. Kollen also uses Entergy Louisiana, LLC's Sterlington Unit 7 as an example of a combined-cycle plant that is still in operation after more than 30 years of service. However, the operational history for Sterlington Unit 7 is significantly different than that of Union PB1. Sterlington Unit 7 was placed in service in 1974 as a combined-cycle unit. So, the technology of the unit is not comparable to that of Union PB1. Additionally, Sterlington Unit 7 was constructed with the capability to also serve as a black start unit. The unit averaged a capacity factor of 14% during the period of 1984 through 2003. In 2003, Sterlington Unit 7 largely was relegated to a primarily reserve role due to changing market conditions and the degradation of the plant equipment, with a capacity factor averaging approximately 1.5% since 2003. The unit's ability to serve as a black start system resource with limited operation was a factor in extending the life of the unit beyond what might have otherwise been feasible.

Q15. ARE THERE ANY NOTEWORTHY CHARACTERISTICS THAT YOU HAVE OBSERVED WITH RESPECT TO EIA DATA REGARDING THOSE CCGTS THAT ARE STILL IN OPERATION?

A. Yes. When analyzing the operating CCGT units that are older than 30 years as set forth on Form EIA-860M (Exhibit RAB-1, p. 2), there appears to be an emerging pattern in the types of CCGTs that are still in operation at that age. That pattern generally reflects (i) significantly smaller plants (*e.g.*, ELL's Sterlington Unit 7) that are significantly smaller in size and have older technology, and (ii) older legacy steam turbines that were repowered.[8] Mr. Kollen does not state in his testimony whether or not these repowered units were included in his analysis of the age of existing CCGT units, but the inclusion of such units in the data set provided by Mr. Kollen would not be comparable to Union PB1.

Q16. IS COMPANY WITNESS DONALD J. CLAYTON'S ASSUMPTION REGARDING THE ESTIMATED USEFUL/SERVICE LIFE OF UNION PB1 REASONABLE?

A. Yes. I would first note that the EIA data cited by Mr. Kollen, when viewed in proper context, supports a 30-year useful life more than it does Mr. Kollen's position. Moreover, in reaching my conclusion, I am relying on my 20 years of responsibility for maintaining CCGTs and discussions with Original Equipment Manufacturers and long-term service providers. The prevailing industry literature, statistical data combined with my years of experience with managing combined-cycle gas turbines leads me to the conclusion that the size, vintage, and operating profile of Union PB1 support Mr. Clayton's recommended 30-year useful life for establishing depreciation rates for this plant.

Q17. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[8] "Repowered" is an industry standard term referring to an older legacy steam-powered power plant where the steam turbine was later paired with one or more combustion turbines and heat recovery steam generators in a combined-cycle configuration after the original utility boiler was retired. These "repowered" units were originally built with design conventions and technology available in the 1950s through 1970s with significantly lower thermal efficiency. In the EIA data, this will be reflected as a CCGT plant with a steam turbine that is 50+ years old, while the combustion turbines are usually less than 20 years old. An example in Louisiana includes Cleco's Coughlin plant.

AFFIDAVIT

STATE OF Texas

COUNTY/PARISH OF Montgomery

NOW BEFORE ME, the undersigned authority, personally came and appeared,

ROBERT BREEDLOVE,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Robert Breedlove

ROBERT BREEDLOVE

Sworn to and

Subscribed Before Me

This 11 Day of March, 2019

Lisa Gatewood

NOTARY PUBLIC

LISA GATEWOOD
Notary Public, State of Tex..
Comm. Expires 07-08-20..
Notary ID 3618776

NOTARY PUBLIC STATE OF TEXAS

LISA GATEWOOD
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Average Service Life Before Retirement (Years): 26.9

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Retirement Year	Operating Year	Balancing Authority Code	Useful Life
58147	Connecticut Valley Hospital	58176	Connecticut Valley Hospital Plant	IPP CHP	CT	ST#2		0.5	0.5	0.5	Natural Gas Fired Combined Cycle	2013	1950	ISNE	63
58147	Connecticut Valley Hospital	58176	Connecticut Valley Hospital Plant	IPP CHP	CT	ST#3		0.5	0.5	0.5	Natural Gas Fired Combined Cycle	2013	1950	ISNE	63
58147	Connecticut Valley Hospital	58176	Connecticut Valley Hospital Plant	IPP CHP	CT	ST#1		0.7	0.7	0.7	Natural Gas Fired Combined Cycle	2013	1950	ISNE	63
56905	Algonquin Power Sanger LLC	57564	Algonquin Power Sanger LLC	IPP Non-CHP	CA	STG		12.5	12.5	12.5	Natural Gas Fired Combined Cycle	2012	1990	CISO	22
56304	Air Products LLC	55309	Air Products Port Arthur	Industrial CHP	TX	GEN2	SMR1	3.0	3.0	3.0	Natural Gas Fired Combined Cycle	2012	2000	MISO	12
6519	Frontera Generation Limited Partnership	55098	Frontera Energy Center	IPP Non-CHP	TX	GEN1	CC1	172.0	177.0	185.0	Natural Gas Fired Combined Cycle	2016	1999	ERCO	17
6519	Frontera Generation Limited Partnership	55098	Frontera Energy Center	IPP Non-CHP	TX	GEN2	CC1	172.0	177.0	185.0	Natural Gas Fired Combined Cycle	2016	1999	ERCO	17
6519	Frontera Generation Limited Partnership	55098	Frontera Energy Center	IPP Non-CHP	TX	GEN3	CC1	185.0	181.0	189.0	Natural Gas Fired Combined Cycle	2016	2000	ERCO	16
19857	Vineland Cogeneration LP	54807	Vineland Cogeneration Plant	IPP CHP	NJ	GEN2		11.9	4.0	4.0	Natural Gas Fired Combined Cycle	2004	1994		10
19857	Vineland Cogeneration LP	54807	Vineland Cogeneration Plant	IPP CHP	NJ	GEN1		42.5	42.5	42.5	Natural Gas Fired Combined Cycle	2004	1994		10
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#3		8.3			Natural Gas Fired Combined Cycle	2004	1989	PJM	15
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#4		8.3			Natural Gas Fired Combined Cycle	2004	1989	PJM	15
60716	Quantum Auburndale Power, LP	54658	Quantum Auburndale Power LP	IPP CHP	FL	ST	CC1	52.0	44.0	45.1	Natural Gas Fired Combined Cycle	2014	1994	TEC	20
60716	Quantum Auburndale Power, LP	54658	Quantum Auburndale Power LP	IPP CHP	FL	CT	CC1	121.5	111.3	117.0	Natural Gas Fired Combined Cycle	2014	1994	TEC	20
56171	Bicent Power	54586	Tanner Street Generation	IPP Non-CHP	MA	V643		65.5	58.0	58.0	Natural Gas Fired Combined Cycle	2007	1992	ISNE	15
50026	Energy Operations Group	54579	Rupert Cogen Project	IPP CHP	ID	1002		10.4	10.4	10.4	Natural Gas Fired Combined Cycle	2016	1996	BPAT	20
50026	Energy Operations Group	54578	Glenns Ferry Cogen Facility	IPP CHP	ID	1001		10.4	10.4	10.4	Natural Gas Fired Combined Cycle	2016	1996	IPCO	20
5892	Energy Systems North East LLC	54571	North East Cogeneration Plant	IPP CHP	PA	GEN3		18.6	10.0	12.0	Natural Gas Fired Combined Cycle	2010	1992		18
5892	Energy Systems North East LLC	54571	North East Cogeneration Plant	IPP CHP	PA	GEN1		34.8	36.5	38.0	Natural Gas Fired Combined Cycle	2010	1992		18
5892	Energy Systems North East LLC	54571	North East Cogeneration Plant	IPP CHP	PA	GEN2		34.8	32.5	34.0	Natural Gas Fired Combined Cycle	2010	1992		18
56375	Graphic Packaging International Inc	54561	Graphic Packaging International	IPP CHP	CA	ST-G	CC1	3.0	3.0	3.0	Natural Gas Fired Combined Cycle	2017	1986	CISO	31
56375	Graphic Packaging International Inc	54561	Graphic Packaging International	IPP CHP	CA	GT-G	CC1	24.0	23.0	24.0	Natural Gas Fired Combined Cycle	2017	1985	CISO	32
60717	Quantum Lake Power, LP	54423	Quantum Lake Power LP	IPP CHP	FL	ST1	CC1	26.5	24.0	24.0	Natural Gas Fired Combined Cycle	2015	1993	FPC	22
60717	Quantum Lake Power, LP	54423	Quantum Lake Power LP	IPP CHP	FL	GT1	CC1	48.8	48.5	48.5	Natural Gas Fired Combined Cycle	2015	1993	FPC	22
60717	Quantum Lake Power, LP	54423	Quantum Lake Power LP	IPP CHP	FL	GT2	CC1	58.9	48.5	48.5	Natural Gas Fired Combined Cycle	2015	1993	FPC	22
4732	Western Power & Steam Inc	54410	Western Power & Steam Inc	Industrial CHP	CA	STG	CC1	8.3	0.0	0.0	Natural Gas Fired Combined Cycle	2015	1990	CISO	25
11459	March Point Cogeneration Co	54268	March Point Cogeneration	IPP CHP	WA	STG1	CC1	27.0	26.0	26.0	Natural Gas Fired Combined Cycle	2015	1993	PSEI	22
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307C		15.6	10.0	12.0	Natural Gas Fired Combined Cycle	2004	1964		40
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307E		15.6	13.5	15.0	Natural Gas Fired Combined Cycle	2004	1966		38
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307F		20.7	14.0	16.0	Natural Gas Fired Combined Cycle	2004	1978		26
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307A		22.0	20.0	20.0	Natural Gas Fired Combined Cycle	2004	1964		40
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307B		22.0	20.0	20.0	Natural Gas Fired Combined Cycle	2004	1964		40
17566	South Houston Green Power LLC	52131	Power Station 3	Industrial CHP	TX	307D		22.0	20.0	20.0	Natural Gas Fired Combined Cycle	2004	1966		38
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-33		49.0	49.0	47.0	Natural Gas Fired Combined Cycle	2007	1953	ERCO	54
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-31		50.0	50.0	50.0	Natural Gas Fired Combined Cycle	2003	1952	ERCO	51
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-42		50.0	46.0	44.0	Natural Gas Fired Combined Cycle	2003	1959	ERCO	44
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-62		94.5	68.3	76.1	Natural Gas Fired Combined Cycle	2011	1982	ERCO	29
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-35		119.0	95.6	106.5	Natural Gas Fired Combined Cycle	2009	1983	ERCO	26
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-36		119.0	99.0	111.0	Natural Gas Fired Combined Cycle	2009	1983	ERCO	26
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-45		119.0	92.0	107.0	Natural Gas Fired Combined Cycle	2003	1983	ERCO	20
50163	Valero Energy Corporation	52108	Valero Energy Port Arthur Refinery	Industrial CHP	TX	GEN3		13.7	12.0	14.0	Natural Gas Fired Combined Cycle	2006	1972	MISO	34

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Retirement Year	Operating Year	Balancing Authority Code	Useful Life
50163	Valero Energy Corporation	52108	Valero Energy Port Arthur Refinery	Industrial CHP	TX	GEN1	CC1	17.2	14.0	15.0	Natural Gas Fired Combined Cycle	2014	1975	MISO	39
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN7		125.0	95.0	114.0	Natural Gas Fired Combined Cycle	2016	1982	MISO	34
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN8		125.0	95.0	114.0	Natural Gas Fired Combined Cycle	2011	1983	MISO	28
5347	Dow Chemical Co	52005	Plaquemine Operations	Industrial CHP	LA	GEN1		53.0	49.0	51.0	Natural Gas Fired Combined Cycle	2002	1969	MISO	33
5347	Dow Chemical Co	52005	Plaquemine Operations	Industrial CHP	LA	GEN2		53.0	49.0	51.0	Natural Gas Fired Combined Cycle	2002	1969	MISO	33
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN26		18.8	9.7	11.7	Natural Gas Fired Combined Cycle	2012	1970	MISO	42
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN27		21.3	4.3	12.0	Natural Gas Fired Combined Cycle	2011	1984	MISO	27
2868	Calpine Monterey Cogen Inc	50968	Watsonville Power Plant	IPP CHP	CA	GEN2		8.0	6.9	7.3	Natural Gas Fired Combined Cycle	2010	1990		20
2868	Calpine Monterey Cogen Inc	50968	Watsonville Power Plant	IPP CHP	CA	GEN1		26.8	22.0	23.0	Natural Gas Fired Combined Cycle	2010	1990		20
14081	Onondaga Cogeneration LP	50855	Onondaga Cogeneration	IPP CHP	NY	GEN2		25.0	25.0	25.0	Natural Gas Fired Combined Cycle	2008	1993		15
14081	Onondaga Cogeneration LP	50855	Onondaga Cogeneration	IPP CHP	NY	GEN3		27.3	23.0	27.3	Natural Gas Fired Combined Cycle	2008	1993		15
14081	Onondaga Cogeneration LP	50855	Onondaga Cogeneration	IPP CHP	NY	GEN1		53.5	45.0	53.5	Natural Gas Fired Combined Cycle	2008	1993		15
2895	Calpine Newark LLC	50797	Newark Power Plant	IPP Non-CHP	NJ	GEN2		18.7	16.1	17.6	Natural Gas Fired Combined Cycle	2009	1990		19
2895	Calpine Newark LLC	50797	Newark Power Plant	IPP Non-CHP	NJ	GEN1		45.9	40.9	42.0	Natural Gas Fired Combined Cycle	2009	1990		19
30897	Sunlaw Energy Partners I LP	50746	Coidgen	IPP Non-CHP	CA	GEN2		7.0	6.0	6.0	Natural Gas Fired Combined Cycle	2002	1986		16
30897	Sunlaw Energy Partners I LP	50746	Coidgen	IPP Non-CHP	CA	GEN1		26.0	22.0	22.0	Natural Gas Fired Combined Cycle	2002	1986		16
30897	Sunlaw Energy Partners I LP	50745	Growgen	IPP Non-CHP	CA	GEN2		7.0	6.0	6.0	Natural Gas Fired Combined Cycle	2002	1986		16
30897	Sunlaw Energy Partners I LP	50745	Growgen	IPP Non-CHP	CA	GEN1		26.0	22.0	22.0	Natural Gas Fired Combined Cycle	2002	1986		16
18801	Thermo Power & Electric LLC	50676	Thermo Power & Electric	IPP CHP	CO	GEN3	CC1	16.4	8.0	7.0	Natural Gas Fired Combined Cycle	2013	1988	PSCO	25
18801	Thermo Power & Electric LLC	50676	Thermo Power & Electric	IPP CHP	CO	GEN1	CC1	47.2	30.0	35.0	Natural Gas Fired Combined Cycle	2013	1988	PSCO	25
18801	Thermo Power & Electric LLC	50676	Thermo Power & Electric	IPP CHP	CO	GEN2	CC1	47.2	30.0	35.0	Natural Gas Fired Combined Cycle	2013	1988	PSCO	25
55983	Luminant Generation Company LLC	50615	TXU Sweetwater Generating Plant	IPP CHP	TX	GT01		45.0	41.0	41.0	Natural Gas Fired Combined Cycle	2012	1989	ERCO	23
55983	Luminant Generation Company LLC	50615	TXU Sweetwater Generating Plant	IPP CHP	TX	GT02		99.0	86.0	86.0	Natural Gas Fired Combined Cycle	2012	1989	ERCO	23
55983	Luminant Generation Company LLC	50615	TXU Sweetwater Generating Plant	IPP CHP	TX	GT03		99.0	86.0	86.0	Natural Gas Fired Combined Cycle	2012	1989	ERCO	23
55983	Luminant Generation Company LLC	50615	TXU Sweetwater Generating Plant	IPP CHP	TX	STG1		101.0	76.0	76.0	Natural Gas Fired Combined Cycle	2009	1989	ERCO	20
56516	Morris Energy Operations Company, LLC	50497	Bayonne Plant Holding LLC	IPP CHP	NJ	GTG1	CC1	43.4	163.0	179.0	Natural Gas Fired Combined Cycle	2018	1988	PJM	30
56516	Morris Energy Operations Company, LLC	50497	Bayonne Plant Holding LLC	IPP CHP	NJ	GTG2	CC1	43.4			Natural Gas Fired Combined Cycle	2018	1988	PJM	30
56516	Morris Energy Operations Company, LLC	50497	Bayonne Plant Holding LLC	IPP CHP	NJ	GTG3	CC1	43.4			Natural Gas Fired Combined Cycle	2018	1988	PJM	30
56516	Morris Energy Operations Company, LLC	50497	Bayonne Plant Holding LLC	IPP CHP	NJ	STG1	CC1	61.4			Natural Gas Fired Combined Cycle	2018	1988	PJM	30
14254	Oxy Vinyls LP	50471	Deer Park Plant	Industrial CHP	TX	GEN1		10.0	8.6	9.4	Natural Gas Fired Combined Cycle	2004	1948		56
14254	Oxy Vinyls LP	50471	Deer Park Plant	Industrial CHP	TX	GEN2		10.0	8.6	9.4	Natural Gas Fired Combined Cycle	2004	1948		56
14254	Oxy Vinyls LP	50471	Deer Park Plant	Industrial CHP	TX	GEN3		10.0	8.6	9.4	Natural Gas Fired Combined Cycle	2004	1948		56
14254	Oxy Vinyls LP	50471	Deer Park Plant	Industrial CHP	TX	GEN4		81.0	69.7	76.1	Natural Gas Fired Combined Cycle	2004	1985		19
9255	Indeck Operations Inc	50459	NRG Ilion LP	IPP CHP	NY	ST		17.8	17.8	17.8	Natural Gas Fired Combined Cycle	2005	1993		12
9255	Indeck Operations Inc	50459	NRG Ilion LP	IPP CHP	NY	GT		43.0	37.0	42.0	Natural Gas Fired Combined Cycle	2005	1993		12
17723	South Florida Cogen Associates	50369	South Florida Cogen Associates	Commercial CHP	FL	GEN2		8.0	8.0	8.0	Natural Gas Fired Combined Cycle	2003	1987		16
17723	South Florida Cogen Associates	50369	South Florida Cogen Associates	Commercial CHP	FL	GEN1		19.9	19.9	19.9	Natural Gas Fired Combined Cycle	2003	1987		16
54711	Basic Chemical Company LLC	50168	Geismar Plant	Industrial CHP	LA	TU01		23.0	20.0	25.0	Natural Gas Fired Combined Cycle	2002	1985		17
54711	Basic Chemical Company LLC	50168	Geismar Plant	Industrial CHP	LA	GT02		45.0	40.0	48.0	Natural Gas Fired Combined Cycle	2003	1985		18
54711	Basic Chemical Company LLC	50168	Geismar Plant	Industrial CHP	LA	GT01		45.0	40.0	48.0	Natural Gas Fired Combined Cycle	2003	1985		18
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	IGT		9.6	9.6	9.6	Natural Gas Fired Combined Cycle	2009	1980	MISO	29
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	CTG		10.0	10.0	10.0	Natural Gas Fired Combined Cycle	2009	1987	MISO	22
56201	Engie North America	50137	Newgulf Cogen	IPP Non-CHP	TX	GEN2		12.5	12.0	12.0	Natural Gas Fired Combined Cycle	2005	1988	ERCO	17
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN6		12.5	12.5	12.5	Natural Gas Fired Combined Cycle	2008	1968	ERCO	40
19491	United Cogen Inc	50104	United Cogen	Commercial CHP	CA	G-2		8.0	7.0	7.0	Natural Gas Fired Combined Cycle	2012	1985		27

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Retirement Year	Operating Year	Balancing Authority Code	Useful Life
19491	United Cogen Inc	50104	United Cogen	Commercial CHP	CA	G-1		23.0	22.0	22.0	Natural Gas Fired Combined Cycle	2012	1985		27
16625	San Diego State University	50061	San Diego State University	Commercial CHP	CA	GEN1		2.5	2.9	2.9	Natural Gas Fired Combined Cycle	2002	1986	CISO	16
7042	Gaylord Container Corp	10886	Gaylord Container Antioch	Industrial CHP	CA	ST1		21.0	21.0	21.0	Natural Gas Fired Combined Cycle	2005	1982		23
7042	Gaylord Container Corp	10886	Gaylord Container Antioch	Industrial CHP	CA	GEN1		44.2	44.0	44.0	Natural Gas Fired Combined Cycle	2005	1982		23
5050	Energy Operation Group	10850	Mojave Cogen	IPP CHP	CA	GEN2	CC1	16.0	15.3	16.0	Natural Gas Fired Combined Cycle	2014	1990	CISO	24
5050	Energy Operation Group	10850	Mojave Cogen	IPP CHP	CA	GEN1	CC1	41.1	41.0	42.0	Natural Gas Fired Combined Cycle	2014	1990	CISO	24
40052	AG Energy LP	10803	Ogdensburg Power	IPP CHP	NY	GEN2		23.6	19.6	21.0	Natural Gas Fired Combined Cycle	2007	1993	NYIS	14
40052	AG Energy LP	10803	Ogdensburg Power	IPP CHP	NY	GEN1		48.8	36.0	42.0	Natural Gas Fired Combined Cycle	2007	1993	NYIS	14
11267	Lowell Cogeneration Co LP	10802	Lowell Cogeneration Company LP	IPP CHP	MA	GEN2		8.5	8.5	8.5	Natural Gas Fired Combined Cycle	2013	1988	ISNE	25
11267	Lowell Cogeneration Co LP	10802	Lowell Cogeneration Company LP	IPP CHP	MA	GEN1		25.0	20.0	23.0	Natural Gas Fired Combined Cycle	2013	1988	ISNE	25
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	GEN4		6.2	5.0	5.0	Natural Gas Fired Combined Cycle	2008	1948	MISO	60
3775	Clear Lake Cogeneration LP	10741	Clear Lake Cogeneration Ltd	IPP CHP	TX	S102	5	14.3	12.1	12.1	Natural Gas Fired Combined Cycle	2017	1985	ERCO	32
3775	Clear Lake Cogeneration LP	10741	Clear Lake Cogeneration Ltd	IPP CHP	TX	S101	5	51.9	50.3	50.3	Natural Gas Fired Combined Cycle	2017	1985	ERCO	32
3775	Clear Lake Cogeneration LP	10741	Clear Lake Cogeneration Ltd	IPP CHP	TX	G102	5	129.0	100.0	115.0	Natural Gas Fired Combined Cycle	2017	1985	ERCO	32
3775	Clear Lake Cogeneration LP	10741	Clear Lake Cogeneration Ltd	IPP CHP	TX	G103	5	129.0	100.0	115.0	Natural Gas Fired Combined Cycle	2017	1985	ERCO	32
3775	Clear Lake Cogeneration LP	10741	Clear Lake Cogeneration Ltd	IPP CHP	TX	G104	5	129.0	100.0	115.0	Natural Gas Fired Combined Cycle	2017	1985	ERCO	32
178	CES Placerita Inc	10677	CES Placerita Power Plant	IPP Non-CHP	CA	UNT1	CESP	60.0	46.0	50.0	Natural Gas Fired Combined Cycle	2008	1988	CISO	20
17607	South Glens Falls Energy LLC	10618	South Glens Falls Energy LLC	IPP CHP	NY	GEN2		22.0	22.6	22.6	Natural Gas Fired Combined Cycle	2006	2001		5
17607	South Glens Falls Energy LLC	10618	South Glens Falls Energy LLC	IPP CHP	NY	GEN1		37.7	40.4	46.8	Natural Gas Fired Combined Cycle	2006	1999		7
4664	Curtis Specialty Papers	10616	Milford Power LP	Industrial CHP	NJ	GEN3		3.5	3.5	3.5	Natural Gas Fired Combined Cycle	2006	1989		17
4664	Curtis Specialty Papers	10616	Milford Power LP	Industrial CHP	NJ	GEN2		5.0	5.0	5.0	Natural Gas Fired Combined Cycle	2006	1989		17
4664	Curtis Specialty Papers	10616	Milford Power LP	Industrial CHP	NJ	GEN1		28.0	26.0	30.0	Natural Gas Fired Combined Cycle	2006	1989		17
21607	Cogent Little Falls GP	10529	Cogent Little Falls GP	Industrial CHP	NY	GEN2		0.5	0.3	0.5	Natural Gas Fired Combined Cycle	2003	1987		16
21607	Cogent Little Falls GP	10529	Cogent Little Falls GP	Industrial CHP	NY	GEN1		4.0	3.8	3.8	Natural Gas Fired Combined Cycle	2003	1987		16
50099	Laidlaw Energy Group Inc.	10403	Laidlaw Energy & Environmental	IPP CHP	NY	WEST		2.0	0.7	0.7	Natural Gas Fired Combined Cycle	2010	1991		19
50099	Laidlaw Energy Group Inc.	10403	Laidlaw Energy & Environmental	IPP CHP	NY	ALLI		3.0	2.6	3.0	Natural Gas Fired Combined Cycle	2010	1991		19
2848	California Institute-Technology	10262	California Institute of Technology	Commercial CHP	CA	GEN1		1.0	1.0	1.0	Natural Gas Fired Combined Cycle	2002	1982	CISO	20
2848	California Institute-Technology	10262	California Institute of Technology	Commercial CHP	CA	GEN2		4.3	4.3	4.3	Natural Gas Fired Combined Cycle	2002	1989	CISO	13
3432	Ticona Polymers Inc	10243	Ticona Polymers Inc	Industrial CHP	TX	GEN4		8.2	5.7	7.4	Natural Gas Fired Combined Cycle	2002	1982	ERCO	20
11161	Loma Linda University	10206	Loma Linda University Cogen	Commercial CHP	CA	GEN3	ST01	1.2	1.2	1.2	Natural Gas Fired Combined Cycle	2014	1980	CISO	34
4558	Cutrale Citrus Juices USA Inc	10188	Cutrale Citrus Juices USA II	Industrial Non-CHP	FL	GEN3		1.5	1.3	1.4	Natural Gas Fired Combined Cycle	2005	1982	TEC	23
4558	Cutrale Citrus Juices USA Inc	10188	Cutrale Citrus Juices USA II	Industrial Non-CHP	FL	GEN1		3.5	3.0	3.7	Natural Gas Fired Combined Cycle	2010	1987	TEC	23
4558	Cutrale Citrus Juices USA Inc	10188	Cutrale Citrus Juices USA II	Industrial Non-CHP	FL	GEN2		3.5	3.0	3.7	Natural Gas Fired Combined Cycle	2010	1987	TEC	23
3030	Cardinal Cogen Inc	10168	Cardinal Cogen	IPP CHP	CA	STG1	CC1	10.7	9.4	8.6	Natural Gas Fired Combined Cycle	2015	1988	CISO	27
3030	Cardinal Cogen Inc	10168	Cardinal Cogen	IPP CHP	CA	GTG1	CC1	42.1	42.1	42.1	Natural Gas Fired Combined Cycle	2015	1987	CISO	28
20323	Wellhead Energy, LLC	10156	Fresno Cogen Partners	IPP CHP	CA	GEN1		22.3	21.5	22.3	Natural Gas Fired Combined Cycle	2004	1990	CISO	14
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	6	CC1	33.0	34.0	37.5	Natural Gas Fired Combined Cycle	2016	1979		37
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	5	CC1	38.1	33.8	37.4	Natural Gas Fired Combined Cycle	2016	1975		41
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	2GT1	C783	85.0			Natural Gas Fired Combined Cycle	2014	1977	FPL	37
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	2GT2	C783	85.0			Natural Gas Fired Combined Cycle	2014	1977	FPL	37
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	1GT1	C782	85.0			Natural Gas Fired Combined Cycle	2014	1978	FPL	36
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	1GT2	C782	85.0			Natural Gas Fired Combined Cycle	2014	1978	FPL	36
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	2ST	C783	120.0	249.0	265.0	Natural Gas Fired Combined Cycle	2014	1977	FPL	37
6452	Florida Power & Light Co	6246	Putnam	Electric Utility	FL	1ST	C782	120.0	249.0	265.0	Natural Gas Fired Combined Cycle	2014	1978	FPL	36
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	IPP Non-CHP	WA	30		60.5	44.0	47.0	Natural Gas Fired Combined Cycle	2013	2002	BPAT	11

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Retirement Year	Operating Year	Balancing Authority Code	Useful Life
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	IPP Non-CHP	WA	40		60.5	44.0	47.0	Natural Gas Fired Combined Cycle	2013	2002	BPAT	11
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	IPP Non-CHP	WA	50		60.5	44.0	47.0	Natural Gas Fired Combined Cycle	2013	2002	BPAT	11
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	IPP Non-CHP	WA	60		60.5	44.0	47.0	Natural Gas Fired Combined Cycle	2013	2002	BPAT	11
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	IPP Non-CHP	WA	70		80.0	80.0	80.0	Natural Gas Fired Combined Cycle	2013	2002	BPAT	11
20404	AEP Texas North Company	3527	San Angelo	IPP Non-CHP	TX	1		25.0	21.0	25.0	Natural Gas Fired Combined Cycle	2004	1965		39
20404	AEP Texas North Company	3527	San Angelo	IPP Non-CHP	TX	2		101.0	102.0	103.0	Natural Gas Fired Combined Cycle	2004	1966		38
20404	AEP Texas North Company	3526	Rio Pecos	IPP Non-CHP	TX	4		5.0	5.0	5.0	Natural Gas Fired Combined Cycle	2005	1954		51
20404	AEP Texas North Company	3526	Rio Pecos	IPP Non-CHP	TX	5		37.5	38.0	38.0	Natural Gas Fired Combined Cycle	2005	1959		46
6204	City of Farmington - (NM)	2465	Animas	Electric Utility	NM	1	CTG1	3.0	3.0	3.0	Natural Gas Fired Combined Cycle	2015	1955	WACM	60
6204	City of Farmington - (NM)	2465	Animas	Electric Utility	NM	2	CTG1	3.0	3.0	3.0	Natural Gas Fired Combined Cycle	2015	1955	WACM	60
15147	PSEG Fossil LLC	2399	PSEG Burlington Generating Station	IPP Non-CHP	NJ	101		44.8	49.0	52.0	Natural Gas Fired Combined Cycle	2004	1993	PJM	11
15147	PSEG Fossil LLC	2399	PSEG Burlington Generating Station	IPP Non-CHP	NJ	102		44.8	49.0	52.0	Natural Gas Fired Combined Cycle	2004	1993	PJM	11
15147	PSEG Fossil LLC	2399	PSEG Burlington Generating Station	IPP Non-CHP	NJ	103		44.8	49.0	52.0	Natural Gas Fired Combined Cycle	2004	1993	PJM	11
15147	PSEG Fossil LLC	2399	PSEG Burlington Generating Station	IPP Non-CHP	NJ	104		44.8	49.0	52.0	Natural Gas Fired Combined Cycle	2004	1993	PJM	11
15147	PSEG Fossil LLC	2399	PSEG Burlington Generating Station	IPP Non-CHP	NJ	105		44.9	49.0	52.0	Natural Gas Fired Combined Cycle	2004	1972	PJM	32
19804	City of Vero Beach - (FL)	693	Vero Beach Municipal Power Plant	Electric Utility	FL	2	G561	16.5	13.0	13.0	Natural Gas Fired Combined Cycle	2015	1964	FMPP	51
19804	City of Vero Beach - (FL)	693	Vero Beach Municipal Power Plant	Electric Utility	FL	5	G561	41.4	35.0	40.0	Natural Gas Fired Combined Cycle	2015	1992	FMPP	23
10376	Kissimmee Utility Authority	672	Hansel	Electric Utility	FL	22		10.0	8.0	6.0	Natural Gas Fired Combined Cycle	2012	1983	FMPP	29
10376	Kissimmee Utility Authority	672	Hansel	Electric Utility	FL	23		10.0	8.0	6.0	Natural Gas Fired Combined Cycle	2012	1983	FMPP	29
10376	Kissimmee Utility Authority	672	Hansel	Electric Utility	FL	21		35.0	30.0	38.0	Natural Gas Fired Combined Cycle	2012	1983	FMPP	29
6616	Fort Pierce Utilities Authority	658	Henry D King	Electric Utility	FL	5		8.3	8.0	8.0	Natural Gas Fired Combined Cycle	2008	1953	FMPP	55
6616	Fort Pierce Utilities Authority	658	Henry D King	Electric Utility	FL	9		22.5	22.4	22.4	Natural Gas Fired Combined Cycle	2008	1990	FMPP	18
2507	City of Burbank Water and Power	375	Magnolia	Electric Utility	CA	M2		10.0	10.0	10.0	Natural Gas Fired Combined Cycle	2002	1984		18
13584	NRG El Segundo Operations Inc	341	Long Beach Generation LLC	IPP Non-CHP	CA	CT5		63.0	63.0	63.0	Natural Gas Fired Combined Cycle	2004	1977	CISO	27
13584	NRG El Segundo Operations Inc	341	Long Beach Generation LLC	IPP Non-CHP	CA	CT6		63.0	63.0	63.0	Natural Gas Fired Combined Cycle	2004	1977	CISO	27
13584	NRG El Segundo Operations Inc	341	Long Beach Generation LLC	IPP Non-CHP	CA	CT7		63.0	63.0	63.0	Natural Gas Fired Combined Cycle	2004	1977	CISO	27
13584	NRG El Segundo Operations Inc	341	Long Beach Generation LLC	IPP Non-CHP	CA	ST9		66.4	63.0	63.0	Natural Gas Fired Combined Cycle	2004	1977	CISO	27
13584	NRG El Segundo Operations Inc	341	Long Beach Generation LLC	IPP Non-CHP	CA	ST8		80.0	80.0	80.0	Natural Gas Fired Combined Cycle	2004	1976	CISO	28
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	31	3	85.0	73.0	73.0	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	32	3	85.0	73.0	73.0	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	41	4	85.0	73.5	73.5	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	42	4	85.0	73.5	73.5	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	30	3	120.0	99.0	99.0	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
15908	NRG California South LP	329	Coolwater	IPP Non-CHP	CA	40	4	120.0	99.0	99.0	Natural Gas Fired Combined Cycle	2014	1978	CISO	36
3522	Chugach Electric Assn Inc	96	Beluga	Electric Utility	AK	8	BCC8	62.0	44.0	53.0	Natural Gas Fired Combined Cycle	2015	1982		33

Red Border Indicates Likely Repowered Unit

Current Average Age (Years): 19.4

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
195	Alabama Power Co	3	Barry	Electric Utility	AL	A1CT	G521	170.1	176.0	184.5	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	SOCO	19
195	Alabama Power Co	3	Barry	Electric Utility	AL	A1CT2	G521	170.1	176.0	184.5	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	SOCO	19
195	Alabama Power Co	3	Barry	Electric Utility	AL	A1ST	G521	195.2	198.0	198.0	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	SOCO	19
195	Alabama Power Co	3	Barry	Electric Utility	AL	A2C1	G522	170.1	178.3	185.5	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	SOCO	19
195	Alabama Power Co	3	Barry	Electric Utility	AL	A2C2	G522	170.1	178.3	185.5	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	SOCO	19
195	Alabama Power Co	3	Barry	Electric Utility	AL	A2ST	G522	195.2	200.6	200.6	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	SOCO	19
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	1B		132.0	85.0	92.0	Natural Gas Fired Combined Cycle	NG	CS	6	1976	Operating	AZPS	43
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	2B		132.0	85.0	92.0	Natural Gas Fired Combined Cycle	NG	CS	6	1976	Operating	AZPS	43
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	3B		132.0	85.0	92.0	Natural Gas Fired Combined Cycle	NG	CS	6	1976	Operating	AZPS	43
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	C4-1	CC1	91.0	68.0	80.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	AZPS	18
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	C4-2	CC1	44.6	39.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	AZPS	18
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	C5-1	CC2	184.5	160.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	AZPS	16
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	C5-2	CC2	184.5	160.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	AZPS	16
803	Arizona Public Service Co	117	West Phoenix	Electric Utility	AZ	C5-3	CC2	200.6	150.0	166.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	AZPS	16
16572	Salt River Project	147	Kyrene	Electric Utility	AZ	KY7	KYS7	170.0	148.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	SRP	17
16572	Salt River Project	147	Kyrene	Electric Utility	AZ	KY7A	KYS7	122.0	106.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	SRP	17
7490	Grand River Dam Authority	165	GREC	Electric Utility	OK	3CT	CT03	369.0	307.0	360.0	Natural Gas Fired Combined Cycle	NG	CT	12	2017	Operating	SWPP	2
7490	Grand River Dam Authority	165	GREC	Electric Utility	OK	3ST	CT03	231.3	160.5	199.5	Natural Gas Fired Combined Cycle	NG	CA	12	2017	Operating	SWPP	2
807	Arkansas Electric Coop Corp	201	Thomas Fitzhugh	Electric Utility	AR	1	FIT1	59.0	61.0	62.0	Natural Gas Fired Combined Cycle	NG	CA	5	1963	Operating	SWPP	56
807	Arkansas Electric Coop Corp	201	Thomas Fitzhugh	Electric Utility	AR	2	FIT1	126.0	101.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	SWPP	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	CT1A	CC1	233.0	165.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	CISO	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	CT1B	CC1	233.0	165.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	CISO	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	ST1	CC1	233.0	180.0	180.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	CISO	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	CT2A	CC2	233.0	165.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	CISO	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	CT2B	CC2	233.0	165.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	CISO	17
54802	Dynegy -Moss Landing LLC	260	Dynegy Moss Landing Power Plant	IPP Non-CHP	CA	ST2	CC2	233.0	180.0	180.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	CISO	17
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV3A	3	164.6	149.0	156.0	Natural Gas Fired Combined Cycle	NG	CT	12	2005	Operating	CISO	14
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV3B	3	164.6	149.0	156.0	Natural Gas Fired Combined Cycle	NG	CT	12	2005	Operating	CISO	14
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV3C	3	189.2	188.0	197.0	Natural Gas Fired Combined Cycle	NG	CA	12	2005	Operating	CISO	14
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV4A	4	164.6	149.0	156.0	Natural Gas Fired Combined Cycle	NG	CT	1	2006	Operating	CISO	13
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV4B	4	164.6	149.0	156.0	Natural Gas Fired Combined Cycle	NG	CT	1	2006	Operating	CISO	13
17609	Southern California Edison Co	358	Mountainview Generating Station	Electric Utility	CA	MV4C	4	189.2	188.0	197.0	Natural Gas Fired Combined Cycle	NG	CA	1	2006	Operating	CISO	13
7294	City of Glendale - (CA)	377	Grayson	Electric Utility	CA	1	CC1	20.0	19.0	19.0	Natural Gas Fired Combined Cycle	NG	CA	7	1977	Operating	LDWP	42
7294	City of Glendale - (CA)	377	Grayson	Electric Utility	CA	2	CC1	20.0	19.0	19.0	Natural Gas Fired Combined Cycle	NG	CA	7	1977	Operating	LDWP	42
7294	City of Glendale - (CA)	377	Grayson	Electric Utility	CA	8A	CC1	25.4	26.0	30.0	Natural Gas Fired Combined Cycle	NG	CT	7	1977	Operating	LDWP	42
7294	City of Glendale - (CA)	377	Grayson	Electric Utility	CA	8BC	CC1	55.1	46.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	7	1977	Operating	LDWP	42
9216	Imperial Irrigation District	389	El Centro	Electric Utility	CA	2	STM2	34.5	31.0	32.5	Natural Gas Fired Combined Cycle	NG	CA	8	1952	Operating	IID	67
9216	Imperial Irrigation District	389	El Centro	Electric Utility	CA	2A	STM2	89.9	71.0	73.0	Natural Gas Fired Combined Cycle	NG	CT	6	1993	Operating	IID	26
9216	Imperial Irrigation District	389	El Centro	Electric Utility	CA	30	STM3	65.9	52.0	53.0	Natural Gas Fired Combined Cycle	NG	CA	10	2012	Operating	IID	7
9216	Imperial Irrigation District	389	El Centro	Electric Utility	CA	31	STM3	43.2	45.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	10	2012	Operating	IID	7
9216	Imperial Irrigation District	389	El Centro	Electric Utility	CA	32	STM3	43.2	45.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	10	2012	Operating	IID	7
11208	Los Angeles Department of Water & Power	399	Harbor	Electric Utility	CA	10A	CC1	85.3	73.0	73.0	Natural Gas Fired Combined Cycle	NG	CT	1	1995	Operating	LDWP	24
11208	Los Angeles Department of Water & Power	399	Harbor	Electric Utility	CA	10B	CC1	85.3	73.0	73.0	Natural Gas Fired Combined Cycle	NG	CT	1	1995	Operating	LDWP	24
11208	Los Angeles Department of Water & Power	399	Harbor	Electric Utility	CA	5	CC1	75.0	56.0	60.0	Natural Gas Fired Combined Cycle	NG	CA	1	1995	Operating	LDWP	24
11208	Los Angeles Department of Water & Power	400	Haynes	Electric Utility	CA	10	CC1	182.8	157.5	162.5	Natural Gas Fired Combined Cycle	NG	CT	1	2005	Operating	LDWP	14
11208	Los Angeles Department of Water & Power	400	Haynes	Electric Utility	CA	8	CC1	264.3	235.0	250.0	Natural Gas Fired Combined Cycle	NG	CA	1	2005	Operating	LDWP	14
11208	Los Angeles Department of Water & Power	400	Haynes	Electric Utility	CA	9	CC1	182.8	162.5	162.5	Natural Gas Fired Combined Cycle	NG	CT	1	2005	Operating	LDWP	14

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
11208	Los Angeles Department of Water & Power	404	Scattergood	Electric Utility	CA	4	CC1	216.9	211.2	211.2	Natural Gas Fired Combined Cycle	NG	CT	10	2015	Operating	LDWP	4
11208	Los Angeles Department of Water & Power	404	Scattergood	Electric Utility	CA	5	CC1	118.9	102.2	102.2	Natural Gas Fired Combined Cycle	NG	CA	11	2015	Operating	LDWP	4
11208	Los Angeles Department of Water & Power	408	Valley (CA)	Electric Utility	CA	6	CC1	182.8	162.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	9	2003	Operating	LDWP	16
11208	Los Angeles Department of Water & Power	408	Valley (CA)	Electric Utility	CA	7	CC1	182.8	162.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	9	2003	Operating	LDWP	16
11208	Los Angeles Department of Water & Power	408	Valley (CA)	Electric Utility	CA	8	CC1	264.4	209.0	209.0	Natural Gas Fired Combined Cycle	NG	CA	11	2003	Operating	LDWP	16
14534	City of Pasadena - (CA)	422	Glenarm	Electric Utility	CA	GT5	0001	71.0	68.0	68.0	Natural Gas Fired Combined Cycle	NG	CT	12	2016	Operating	CISO	3
14534	City of Pasadena - (CA)	422	Glenarm	Electric Utility	CA	ST1	0001	16.0	16.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	12	2016	Operating	CISO	3
15466	Public Service Co of Colorado	469	Cherokee	Electric Utility	CO	5	CHR0	185.3	168.0	176.0	Natural Gas Fired Combined Cycle	NG	CT	8	2015	Operating	PSCO	4
15466	Public Service Co of Colorado	469	Cherokee	Electric Utility	CO	6	CHR0	185.3	168.0	176.0	Natural Gas Fired Combined Cycle	NG	CT	8	2015	Operating	PSCO	4
15466	Public Service Co of Colorado	469	Cherokee	Electric Utility	CO	7	CHR0	255.0	240.0	248.0	Natural Gas Fired Combined Cycle	NG	CA	8	2015	Operating	PSCO	4
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	1	MCWM	7.5	9.0	9.0	Natural Gas Fired Combined Cycle	NG	CA	12	1954	Operating	AEC	65
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	2	MCWM	7.5	9.0	9.0	Natural Gas Fired Combined Cycle	NG	CA	12	1954	Operating	AEC	65
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	3	MCWM	25.0	22.0	22.0	Natural Gas Fired Combined Cycle	NG	CA	8	1959	Operating	AEC	60
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	4	MCWM	107.0	108.0	116.0	Natural Gas Fired Combined Cycle	NG	CT	12	1996	Operating	AEC	23
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	VAN1	VANN	165.0	171.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	AEC	17
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	VAN2	VANN	165.0	168.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	AEC	17
189	PowerSouth Energy Cooperative	533	McWilliams	Electric Utility	AL	VAN3	VANN	177.0	176.0	185.0	Natural Gas Fired Combined Cycle	NG	CA	1	2002	Operating	AEC	17
14610	Orlando Utilities Comm	564	Stanton Energy Center	Electric Utility	FL	B	OUC	129.8	128.0	130.0	Natural Gas Fired Combined Cycle	NG	CA	2	2010	Operating	FMPP	9
14610	Orlando Utilities Comm	564	Stanton Energy Center	Electric Utility	FL	B1	OUC	203.2	167.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	2	2010	Operating	FMPP	9
6452	Florida Power & Light Co	609	Cape Canaveral	Electric Utility	FL	3A	PCC	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2013	Operating	FPL	6
6452	Florida Power & Light Co	609	Cape Canaveral	Electric Utility	FL	3B	PCC	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2013	Operating	FPL	6
6452	Florida Power & Light Co	609	Cape Canaveral	Electric Utility	FL	3C	PCC	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2013	Operating	FPL	6
6452	Florida Power & Light Co	609	Cape Canaveral	Electric Utility	FL	3ST	PCC	500.0	1,210.0	1,355.0	Natural Gas Fired Combined Cycle	NG	CA	4	2013	Operating	FPL	6
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	ST1	F901	156.2	1,432.0	1,490.0	Natural Gas Fired Combined Cycle	NG	CA	11	1958	Operating	FPL	61
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	ST2	F901	436.1			Natural Gas Fired Combined Cycle	NG	CA	7	1969	Operating	FPL	50
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2A	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	FPL	19
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2B	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	FPL	19
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2C	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	FPL	19
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2D	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	4	2001	Operating	FPL	18
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2E	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	FPL	18
6452	Florida Power & Light Co	612	Fort Myers	Electric Utility	FL	2F	F901	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	FPL	18
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	ST4	C791	151.2	442.0	485.0	Natural Gas Fired Combined Cycle	NG	CA	10	1957	Operating	FPL	62
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	4GT1	C791	185.0			Natural Gas Fired Combined Cycle	NG	CT	5	1993	Operating	FPL	26
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	4GT2	C791	185.0			Natural Gas Fired Combined Cycle	NG	CT	5	1993	Operating	FPL	26
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	ST5	C792	151.2	442.0	485.0	Natural Gas Fired Combined Cycle	NG	CA	4	1958	Operating	FPL	61
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	5GT1	C792	185.0			Natural Gas Fired Combined Cycle	NG	CT	6	1993	Operating	FPL	26
6452	Florida Power & Light Co	613	Lauderdale	Electric Utility	FL	5GT2	C792	185.0			Natural Gas Fired Combined Cycle	NG	CT	6	1993	Operating	FPL	26
6452	Florida Power & Light Co	617	Port Everglades	Electric Utility	FL	5A	CC1	296.0	1,260.0	1,370.0	Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	FPL	3
6452	Florida Power & Light Co	617	Port Everglades	Electric Utility	FL	5B	CC1	296.0			Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	FPL	3
6452	Florida Power & Light Co	617	Port Everglades	Electric Utility	FL	5C	CC1	296.0			Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	FPL	3
6452	Florida Power & Light Co	617	Port Everglades	Electric Utility	FL	5ST	CC1	464.0			Natural Gas Fired Combined Cycle	NG	CA	4	2016	Operating	FPL	3
6452	Florida Power & Light Co	619	Riviera	Electric Utility	FL	5A	PRV	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2014	Operating	FPL	5
6452	Florida Power & Light Co	619	Riviera	Electric Utility	FL	5B	PRV	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2014	Operating	FPL	5
6452	Florida Power & Light Co	619	Riviera	Electric Utility	FL	5C	PRV	265.0			Natural Gas Fired Combined Cycle	NG	CT	4	2014	Operating	FPL	5
6452	Florida Power & Light Co	619	Riviera	Electric Utility	FL	5ST	PRV	500.0	1,212.0	1,344.0	Natural Gas Fired Combined Cycle	NG	CA	4	2014	Operating	FPL	5
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	4	G160	436.1	958.0	1,040.0	Natural Gas Fired Combined Cycle	NG	CA	7	1969	Operating	FPL	50
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	4A	G160	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	4B	G160	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	4C	G160	188.2			Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	4D	G160	188.2			Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	FPL	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	5	G161	436.1	954.0	1,037.0	Natural Gas Fired Combined Cycle	NG	CA	5	1974	Operating	FPL	45
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	5A	G161	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	5B	G161	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	5C	G161	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	FPL	17
6452	Florida Power & Light Co	620	Sanford	Electric Utility	FL	5D	G161	188.2			Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	FPL	17
6452	Florida Power & Light Co	621	Turkey Point	Electric Utility	FL	5CA	G901	472.0	1,148.0	1,178.0	Natural Gas Fired Combined Cycle	NG	CA	5	2007	Operating	FPL	12
6452	Florida Power & Light Co	621	Turkey Point	Electric Utility	FL	5CTA	G901	188.0			Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	FPL	12
6452	Florida Power & Light Co	621	Turkey Point	Electric Utility	FL	5CTB	G901	188.0			Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	FPL	12
6452	Florida Power & Light Co	621	Turkey Point	Electric Utility	FL	5CTC	G901	188.0			Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	FPL	12
6452	Florida Power & Light Co	621	Turkey Point	Electric Utility	FL	5CTD	G901	188.0			Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	FPL	12
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	1GTA	CC1	310.3	251.7	293.8	Natural Gas Fired Combined Cycle	NG	CT	10	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	1GTB	CC1	310.3	251.7	293.8	Natural Gas Fired Combined Cycle	NG	CT	10	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	CC1ST	CC1	364.7	316.7	322.4	Natural Gas Fired Combined Cycle	NG	CA	10	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	2GTA	CC2	310.3	244.0	299.0	Natural Gas Fired Combined Cycle	NG	CT	11	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	2GTB	CC2	310.3	244.0	299.0	Natural Gas Fired Combined Cycle	NG	CT	11	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	628	Crystal River	Electric Utility	FL	CC2ST	CC2	364.7	328.0	333.0	Natural Gas Fired Combined Cycle	NG	CA	11	2018	Operating	FPC	1
6455	Duke Energy Florida, LLC	634	P L Bartow	Electric Utility	FL	4AGT	G981	208.2	185.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	FPC	10
6455	Duke Energy Florida, LLC	634	P L Bartow	Electric Utility	FL	4BGT	G981	208.2	183.0	209.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	FPC	10
6455	Duke Energy Florida, LLC	634	P L Bartow	Electric Utility	FL	4CGT	G981	208.2	187.0	219.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	FPC	10
6455	Duke Energy Florida, LLC	634	P L Bartow	Electric Utility	FL	4DGT	G981	208.2	186.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	FPC	10
6455	Duke Energy Florida, LLC	634	P L Bartow	Electric Utility	FL	4ST	G981	421.2	339.0	329.0	Natural Gas Fired Combined Cycle	NG	CA	6	2009	Operating	FPC	10
7801	Gulf Power Co	643	Lansing Smith	Electric Utility	FL	3A	G180	203.2			Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	SOCO	17
7801	Gulf Power Co	643	Lansing Smith	Electric Utility	FL	3B	G180	203.2			Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	SOCO	17
7801	Gulf Power Co	643	Lansing Smith	Electric Utility	FL	3S	G180	213.3	502.0	552.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	SOCO	17
6909	Gainesville Regional Utilities	664	John R Kelly	Electric Utility	FL	8	G681	50.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CA	4	1965	Operating	GVL	54
6909	Gainesville Regional Utilities	664	John R Kelly	Electric Utility	FL	CT04	G681	96.1	75.0	81.0	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	GVL	18
10620	City of Lake Worth - (FL)	673	Tom G Smith	Electric Utility	FL	GT2	CC1	21.4	21.0	23.0	Natural Gas Fired Combined Cycle	NG	CT	3	1978	Operating	FMPP	41
10620	City of Lake Worth - (FL)	673	Tom G Smith	Electric Utility	FL	S5	CC1	10.0	10.0	10.0	Natural Gas Fired Combined Cycle	NG	CA	3	1978	Operating	FMPP	41
10623	City of Lakeland - (FL)	675	Larsen Memorial	Electric Utility	FL	5	8CC	25.0	29.0	31.0	Natural Gas Fired Combined Cycle	NG	CA	4	1956	Operating	FMPP	63
10623	City of Lakeland - (FL)	675	Larsen Memorial	Electric Utility	FL	8	8CC	86.2	76.0	93.0	Natural Gas Fired Combined Cycle	NG	CT	7	1992	Operating	FMPP	27
10623	City of Lakeland - (FL)	676	C D McIntosh Jr	Electric Utility	FL	5CT	5CC	249.0	215.0	233.0	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	FMPP	18
10623	City of Lakeland - (FL)	676	C D McIntosh Jr	Electric Utility	FL	5ST	5CC	120.0	123.0	121.0	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	FMPP	17
18445	City of Tallahassee - (FL)	688	Arvah B Hopkins	Electric Utility	FL	2	CC1	259.2	141.0	145.0	Natural Gas Fired Combined Cycle	NG	CA	10	1977	Operating	TAL	42
18445	City of Tallahassee - (FL)	688	Arvah B Hopkins	Electric Utility	FL	CT 2A	CC1	198.9	159.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	10	2008	Operating	TAL	11
18445	City of Tallahassee - (FL)	689	S O Purdom	Electric Utility	FL	8	CC1	180.0	154.0	182.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	Operating	TAL	19
18445	City of Tallahassee - (FL)	689	S O Purdom	Electric Utility	FL	9	CC1	90.1	72.0	76.0	Natural Gas Fired Combined Cycle	NG	CA	7	2000	Operating	TAL	19
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	4	G104	375.0	375.0	375.0	Natural Gas Fired Combined Cycle	NG	CA	12	2011	Operating	SOCO	8
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	CT4A	G104	232.5	223.0	265.0	Natural Gas Fired Combined Cycle	NG	CT	12	2011	Operating	SOCO	8
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	CT4B	G104	232.5	223.0	265.0	Natural Gas Fired Combined Cycle	NG	CT	12	2011	Operating	SOCO	8
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	5	G105	375.0	375.0	375.0	Natural Gas Fired Combined Cycle	NG	CA	4	2012	Operating	SOCO	7
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	5ACT	G105	232.5	224.0	266.0	Natural Gas Fired Combined Cycle	NG	CT	4	2012	Operating	SOCO	7
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	5BCT	G105	232.5	224.0	266.0	Natural Gas Fired Combined Cycle	NG	CT	4	2012	Operating	SOCO	7
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	6	G106	375.0	375.0	375.0	Natural Gas Fired Combined Cycle	NG	CA	10	2012	Operating	SOCO	7
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	6ACT	G106	232.5	225.5	267.5	Natural Gas Fired Combined Cycle	NG	CT	10	2012	Operating	SOCO	7
7140	Georgia Power Co	710	Jack McDonough	Electric Utility	GA	6BCT	G106	232.5	225.5	267.5	Natural Gas Fired Combined Cycle	NG	CT	10	2012	Operating	SOCO	7
59371	Mainline Generation LLC	862	Grand Tower Energy Center LLC	IPP Non-CHP	IL	3	CC01	80.9	86.0	86.0	Natural Gas Fired Combined Cycle	NG	CA	3	1951	Operating	MISO	68
59371	Mainline Generation LLC	862	Grand Tower Energy Center LLC	IPP Non-CHP	IL	1	CC01	223.2	161.0	182.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	MISO	18
59371	Mainline Generation LLC	862	Grand Tower Energy Center LLC	IPP Non-CHP	IL	4	CC02	113.6	105.0	105.0	Natural Gas Fired Combined Cycle	NG	CA	4	1958	Operating	MISO	61
59371	Mainline Generation LLC	862	Grand Tower Energy Center LLC	IPP Non-CHP	IL	2	CC02	223.2	159.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	MISO	18
9273	Indianapolis Power & Light Co	991	Eagle Valley (IN)	Electric Utility	IN	GT1	EGVS	207.0	207.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	MISO	1

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
9273	Indianapolis Power & Light Co	991	Eagle Valley (IN)	Electric Utility	IN	GT2	EGVS	207.0	207.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	MISO	1
9273	Indianapolis Power & Light Co	991	Eagle Valley (IN)	Electric Utility	IN	STG1	EGVS	230.0	230.0	230.0	Natural Gas Fired Combined Cycle	NG	CA	4	2018	Operating	MISO	1
15470	Duke Energy Indiana, LLC	1007	Noblesville	Electric Utility	IN	1	CC1	50.0	43.0	44.0	Natural Gas Fired Combined Cycle	NG	CA	12	1950	Operating	MISO	69
15470	Duke Energy Indiana, LLC	1007	Noblesville	Electric Utility	IN	2	CC1	50.0	44.0	45.0	Natural Gas Fired Combined Cycle	NG	CA	9	1950	Operating	MISO	69
15470	Duke Energy Indiana, LLC	1007	Noblesville	Electric Utility	IN	3	CC1	61.0	59.0	73.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
15470	Duke Energy Indiana, LLC	1007	Noblesville	Electric Utility	IN	4	CC1	61.0	60.0	74.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
15470	Duke Energy Indiana, LLC	1007	Noblesville	Electric Utility	IN	5	CC1	61.0	58.0	74.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	1	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	12	1976	Operating	CPLE	43
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	2	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	12	1976	Operating	CPLE	43
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	3	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	7	1976	Operating	CPLE	43
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	6	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	6	1978	Operating	CPLE	41
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	7	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	6	1979	Operating	CPLE	40
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	8	CC1	28.8	20.0	25.0	Natural Gas Fired Combined Cycle	NG	CT	5	1980	Operating	CPLE	39
6235	Fayetteville Public Works Commission	1016	Butler-Warner Generation Plant	Electric Utility	NC	9	CC1	73.0	65.0	65.0	Natural Gas Fired Combined Cycle	NG	CA	12	1988	Operating	CPLE	31
3258	Central Iowa Power Cooperative	1206	Summit Lake	Electric Utility	IA	1	SLCC	7.5	6.5	6.8	Natural Gas Fired Combined Cycle	NG	CA	3	1951	Operating	MISO	68
3258	Central Iowa Power Cooperative	1206	Summit Lake	Electric Utility	IA	2	SLCC	7.5	6.5	6.8	Natural Gas Fired Combined Cycle	NG	CA	3	1951	Operating	MISO	68
3258	Central Iowa Power Cooperative	1206	Summit Lake	Electric Utility	IA	3	SLCC	7.5	7.0	7.3	Natural Gas Fired Combined Cycle	NG	CA	10	1957	Operating	MISO	62
3258	Central Iowa Power Cooperative	1206	Summit Lake	Electric Utility	IA	GT1	SLCC	27.0	27.5	31.9	Natural Gas Fired Combined Cycle	NG	CT	7	1973	Operating	MISO	46
3258	Central Iowa Power Cooperative	1206	Summit Lake	Electric Utility	IA	GT2	SLCC	35.3	27.9	32.4	Natural Gas Fired Combined Cycle	NG	CT	6	1975	Operating	MISO	44
5860	Empire District Electric Co	1239	Riverton	Electric Utility	KS	12	CC1	148.8	149.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	SWPP	12
5860	Empire District Electric Co	1239	Riverton	Electric Utility	KS	12-2	CC1	118.8	117.0	117.0	Natural Gas Fired Combined Cycle	NG	CA	5	2016	Operating	SWPP	3
11249	Louisville Gas & Electric Co	1363	Cane Run	Electric Utility	KY	7A	7ABS	260.0	213.0	226.0	Natural Gas Fired Combined Cycle	NG	CT	6	2015	Operating	LGEE	4
11249	Louisville Gas & Electric Co	1363	Cane Run	Electric Utility	KY	7B	7ABS	260.0	213.0	226.0	Natural Gas Fired Combined Cycle	NG	CT	6	2015	Operating	LGEE	4
11249	Louisville Gas & Electric Co	1363	Cane Run	Electric Utility	KY	7S	7ABS	287.0	237.0	231.0	Natural Gas Fired Combined Cycle	NG	CA	6	2015	Operating	LGEE	4
18642	Tennessee Valley Authority	1378	Paradise	Electric Utility	KY	CTG1	CC1	231.0	211.0	231.0	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	TVA	2
18642	Tennessee Valley Authority	1378	Paradise	Electric Utility	KY	CTG2	CC1	231.0	211.0	231.0	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	TVA	2
18642	Tennessee Valley Authority	1378	Paradise	Electric Utility	KY	CTG3	CC1	231.0	211.0	231.0	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	TVA	2
18642	Tennessee Valley Authority	1378	Paradise	Electric Utility	KY	STG1	CC1	467.0	467.0	467.0	Natural Gas Fired Combined Cycle	NG	CA	4	2017	Operating	TVA	2
3265	Cleco Power LLC	1396	Coughlin Power Station	Electric Utility	LA	6	CC6	113.6	97.9		Natural Gas Fired Combined Cycle	NG	CA	4	1961	Operating	MISO	58
3265	Cleco Power LLC	1396	Coughlin Power Station	Electric Utility	LA	U6CT	CC6	188.7	153.8		Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	MISO	19
3265	Cleco Power LLC	1396	Coughlin Power Station	Electric Utility	LA	7	CC7	243.1	178.6		Natural Gas Fired Combined Cycle	NG	CA	2	1966	Operating	MISO	53
3265	Cleco Power LLC	1396	Coughlin Power Station	Electric Utility	LA	U72	CC7	188.7	152.6		Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	MISO	19
3265	Cleco Power LLC	1396	Coughlin Power Station	Electric Utility	LA	U7CT	CC7	188.7	149.1		Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	MISO	19
11241	Entergy Louisiana LLC	1403	Nine Mile Point	Electric Utility	LA	6A	PB01	194.7			Natural Gas Fired Combined Cycle	NG	CT	12	2014	Operating	MISO	5
11241	Entergy Louisiana LLC	1403	Nine Mile Point	Electric Utility	LA	6B	PB01	194.7			Natural Gas Fired Combined Cycle	NG	CT	12	2014	Operating	MISO	5
11241	Entergy Louisiana LLC	1403	Nine Mile Point	Electric Utility	LA	6C	PB01	260.1	560.2	608.0	Natural Gas Fired Combined Cycle	NG	CA	12	2014	Operating	MISO	5
11241	Entergy Louisiana LLC	1404	Sterlington	Electric Utility	LA	7A	PB01	59.3	46.9	51.8	Natural Gas Fired Combined Cycle	NG	CT	4	1973	Operating	MISO	46
11241	Entergy Louisiana LLC	1404	Sterlington	Electric Utility	LA	7B	PB01	66.0	44.0	55.0	Natural Gas Fired Combined Cycle	NG	CT	4	1973	of service	MISO	46
11241	Entergy Louisiana LLC	1404	Sterlington	Electric Utility	LA	7C	PB01	101.0	59.2	14.0	Natural Gas Fired Combined Cycle	NG	CA	9	1974	Operating	MISO	45
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	GT81	G941	278.6	224.6	268.7	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ISNE	16
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	GT82	G941	278.6	226.7	271.2	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ISNE	16
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	GT93	G942	278.6	227.9	274.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	ISNE	16
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	GT94	G942	278.6	230.1	276.7	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	ISNE	16
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	ST85	G941	315.0	252.0	301.7	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	ISNE	16
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	IPP Non-CHP	MA	ST96	G942	315.0	255.9	307.7	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	ISNE	16
59528	Veolia - Kendall Green Energy	1595	Kendall Square Station	IPP CHP	MA	1	CC1	17.2	14.8	14.8	Natural Gas Fired Combined Cycle	NG	CA	6	1949	of service	ISNE	70
59528	Veolia - Kendall Green Energy	1595	Kendall Square Station	IPP CHP	MA	2	CC1	23.0	19.7	19.7	Natural Gas Fired Combined Cycle	NG	CA	1	1951	of service	ISNE	68
59528	Veolia - Kendall Green Energy	1595	Kendall Square Station	IPP CHP	MA	3	CC1	27.2	20.4	20.4	Natural Gas Fired Combined Cycle	NG	CA	8	1958	Operating	ISNE	61
59528	Veolia - Kendall Green Energy	1595	Kendall Square Station	IPP CHP	MA	GEN4	CC1	186.2	171.0	187.4	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	ISNE	17
2144	Town of Braintree - (MA)	1660	Potter Station 2	Electric Utility	MA	CC2	POT2	76.0	62.6	77.6	Natural Gas Fired Combined Cycle	NG	CT	4	1977	Operating	ISNE	42

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
2144	Town of Braintree - (MA)	1660	Potter Station 2	Electric Utility	MA	CC3	POT2	25.0	15.5	18.5	Natural Gas Fired Combined Cycle	NG	CA	4	1977	Operating	ISNE	42
18488	City of Taunton	1682	Cleary Flood	Electric Utility	MA	CA9	CC1	95.0	87.0	85.0	Natural Gas Fired Combined Cycle	NG	CA	12	1975	Operating	ISNE	44
18488	City of Taunton	1682	Cleary Flood	Electric Utility	MA	9A	CC1	23.0	18.0	21.4	Natural Gas Fired Combined Cycle	NG	CT	10	1976	Operating	ISNE	43
20910	Wolverine Power Supply Coop	1880	Claude Vandyke	Electric Utility	MI	6		23.0	19.3	23.9	Natural Gas Fired Combined Cycle	NG	CS	1	1967	Operating	MISO	52
13781	Northern States Power Co - Minnesota	1904	Black Dog	Electric Utility	MN	2	BDS0	136.9	110.0	109.0	Natural Gas Fired Combined Cycle	NG	CA	10	1954	Operating	MISO	65
13781	Northern States Power Co - Minnesota	1904	Black Dog	Electric Utility	MN	5	BDS0	187.9	172.0	189.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
13781	Northern States Power Co - Minnesota	1912	High Bridge	Electric Utility	MN	7	HBR0	197.0	152.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	MISO	11
13781	Northern States Power Co - Minnesota	1912	High Bridge	Electric Utility	MN	8	HBR0	197.0	152.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	MISO	11
13781	Northern States Power Co - Minnesota	1912	High Bridge	Electric Utility	MN	9	HBR0	250.0	226.0	236.0	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	MISO	11
13781	Northern States Power Co - Minnesota	1927	Riverside (MN)	Electric Utility	MN	ST7	RIV0	164.7	160.0	158.0	Natural Gas Fired Combined Cycle	NG	CA	4	1987	Operating	MISO	32
13781	Northern States Power Co - Minnesota	1927	Riverside (MN)	Electric Utility	MN	10	RIV0	210.6	147.0	171.0	Natural Gas Fired Combined Cycle	NG	CT	5	2009	Operating	MISO	10
13781	Northern States Power Co - Minnesota	1927	Riverside (MN)	Electric Utility	MN	9	RIV0	210.6	147.0	171.0	Natural Gas Fired Combined Cycle	NG	CT	5	2009	Operating	MISO	10
9130	Hutchinson Utilities Comm	1980	Hutchinson Plant #1	Electric Utility	MN	8		16.0	13.0	13.3	Natural Gas Fired Combined Cycle	NG	CS	1	1971	Operating	MISO	48
3702	Clarksdale Public Utilities	2059	L L Wilkins	Electric Utility	MS	7	CC1	7.5	7.5	7.5	Natural Gas Fired Combined Cycle	NG	CT	10	1961	Operating	MISO	58
3702	Clarksdale Public Utilities	2059	L L Wilkins	Electric Utility	MS	8	CC1	16.2	13.2	15.0	Natural Gas Fired Combined Cycle	NG	CT	10	1965	Operating	MISO	54
3702	Clarksdale Public Utilities	2059	L L Wilkins	Electric Utility	MS	9		25.5	22.0	23.0	Natural Gas Fired Combined Cycle	NG	CS	10	1971	Operating	MISO	48
3702	Clarksdale Public Utilities	2059	L L Wilkins	Electric Utility	MS	6	CC1	6.0	6.8	6.8	Natural Gas Fired Combined Cycle	NG	CA	10	1996	Operating	MISO	23
21095	Public Serv Comm of Yazoo City	2067	Yazoo	Electric Utility	MS	2	CC1	5.0	5.6	5.6	Natural Gas Fired Combined Cycle	NG	CA	6	1945	Standby/	MISO	74
21095	Public Serv Comm of Yazoo City	2067	Yazoo	Electric Utility	MS	3	CC1	12.6	13.0	13.0	Natural Gas Fired Combined Cycle	NG	CA	7	1954	Operating	MISO	65
21095	Public Serv Comm of Yazoo City	2067	Yazoo	Electric Utility	MS	GT1	CC1	16.5	14.7	16.7	Natural Gas Fired Combined Cycle	NG	CT	4	1968	Operating	MISO	51
17568	Cooperative Energy	2070	Moselle	Electric Utility	MS	1	CC1	59.0	59.0	59.0	Natural Gas Fired Combined Cycle	NG	CA	8	1970	Operating	MISO	49
17568	Cooperative Energy	2070	Moselle	Electric Utility	MS	GTG1	CC1	83.5	75.0	83.5	Natural Gas Fired Combined Cycle	NG	CT	5	2012	Operating	MISO	7
17568	Cooperative Energy	2070	Moselle	Electric Utility	MS	2	CC2	59.0	59.0	59.0	Natural Gas Fired Combined Cycle	NG	CA	8	1970	Operating	MISO	49
17568	Cooperative Energy	2070	Moselle	Electric Utility	MS	GTG2	CC2	83.5	75.0	83.5	Natural Gas Fired Combined Cycle	NG	CT	11	2012	Operating	MISO	7
10000	Kansas City Power & Light Co	2079	Hawthorn	Electric Utility	MO	6	CC1	176.0	124.1	124.1	Natural Gas Fired Combined Cycle	NG	CT	6	1997	Operating	SWPP	22
10000	Kansas City Power & Light Co	2079	Hawthorn	Electric Utility	MO	9	CC1	146.0	110.4	110.4	Natural Gas Fired Combined Cycle	NG	CA	7	2000	Operating	SWPP	19
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	GT5	PB1	92.5	73.0	81.0	Natural Gas Fired Combined Cycle	NG	CT	5	1979	Operating	NEVP	40
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	GT6	PB1	92.5	73.0	81.0	Natural Gas Fired Combined Cycle	NG	CT	5	1979	Operating	NEVP	40
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	10	PB1	104.4	85.0	88.0	Natural Gas Fired Combined Cycle	NG	CA	5	1994	Operating	NEVP	25
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	GT7	PB2	92.5	73.0	81.0	Natural Gas Fired Combined Cycle	NG	CT	6	1980	Operating	NEVP	39
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	GT8	PB2	92.5	73.0	81.0	Natural Gas Fired Combined Cycle	NG	CT	6	1982	Operating	NEVP	37
13407	Nevada Power Co	2322	Clark (NVE)	Electric Utility	NV	9	PB2	104.4	85.0	88.0	Natural Gas Fired Combined Cycle	NG	CA	5	1993	Operating	NEVP	26
17166	Sierra Pacific Power Co	2336	Tracy	Electric Utility	NV	4	G240	69.7	64.0	68.0	Natural Gas Fired Combined Cycle	NG	CT	7	1994	Operating	NEVP	25
17166	Sierra Pacific Power Co	2336	Tracy	Electric Utility	NV	5	G240	50.2	40.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	12	1996	Operating	NEVP	23
17166	Sierra Pacific Power Co	2336	Tracy	Electric Utility	NV	10	PB1	312.0	263.0	286.0	Natural Gas Fired Combined Cycle	NG	CA	7	2008	Operating	NEVP	11
17166	Sierra Pacific Power Co	2336	Tracy	Electric Utility	NV	8	PB1	155.6	145.0	146.0	Natural Gas Fired Combined Cycle	NG	CT	7	2008	Operating	NEVP	11
17166	Sierra Pacific Power Co	2336	Tracy	Electric Utility	NV	9	PB1	155.6	145.0	146.0	Natural Gas Fired Combined Cycle	NG	CT	7	2008	Operating	NEVP	11
17235	NRG REMA LLC	2393	Gilbert	IPP Non-CHP	NJ	4	CC1	54.0	47.0	56.0	Natural Gas Fired Combined Cycle	NG	CT	1	1974	Operating	PJM	45
17235	NRG REMA LLC	2393	Gilbert	IPP Non-CHP	NJ	5	CC1	54.0	47.0	56.0	Natural Gas Fired Combined Cycle	NG	CT	4	1974	Operating	PJM	45
17235	NRG REMA LLC	2393	Gilbert	IPP Non-CHP	NJ	6	CC1	54.0	49.0	56.0	Natural Gas Fired Combined Cycle	NG	CT	4	1974	Operating	PJM	45
17235	NRG REMA LLC	2393	Gilbert	IPP Non-CHP	NJ	7	CC1	54.0	47.0	56.0	Natural Gas Fired Combined Cycle	NG	CT	5	1974	Operating	PJM	45
17235	NRG REMA LLC	2393	Gilbert	IPP Non-CHP	NJ	8	CC1	135.0	104.0	108.0	Natural Gas Fired Combined Cycle	NG	CA	5	1977	Operating	PJM	42
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	1501	CC1	325.2	198.0	198.0	Natural Gas Fired Combined Cycle	NG	CA	5	1959	Operating	PJM	60
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	1101	CC1	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	PJM	24
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	1201	CC1	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	PJM	24
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	1301	CC1	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	PJM	24
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	1401	CC1	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	PJM	24
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	2101	CC1	183.6	177.3	177.3	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	PJM	17
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	2201	CC1	183.6	177.3	177.3	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	PJM	17
15147	PSEG Fossil LLC	2398	Bergen Generating Station	IPP Non-CHP	NJ	2301	CC1	258.4	236.4	236.4	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	PJM	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	1001	CC1	315.0	238.4	238.4	Natural Gas Fired Combined Cycle	NG	CA	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	1101	CC1	181.4	188.3	188.3	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	1201	CC1	181.4	188.3	188.3	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	2001	CC2	315.0	238.4	238.4	Natural Gas Fired Combined Cycle	NG	CA	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	2101	CC2	181.4	188.3	188.3	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2406	PSEG Linden Generating Station	IPP Non-CHP	NJ	2201	CC2	181.4	188.3	188.3	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PJM	13
15147	PSEG Fossil LLC	2411	PSEG Sewaren Generating Station	IPP Non-CHP	NJ	701		365.5	328.0	328.0	Natural Gas Fired Combined Cycle	NG	CT	6	2018	Operating	PJM	1
15147	PSEG Fossil LLC	2411	PSEG Sewaren Generating Station	IPP Non-CHP	NJ	702		244.0	196.5	196.5	Natural Gas Fired Combined Cycle	NG	CA	6	2018	Operating	PJM	1
61130	Helix Ravenswood, LLC	2500	Ravenswood	IPP Non-CHP	NY	4	CCR4	170.0	169.7	194.2	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	NYIS	16
61130	Helix Ravenswood, LLC	2500	Ravenswood	IPP Non-CHP	NY	4S	CCR4	80.0	79.1	82.7	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	NYIS	16
14294	PSEG Power New York Inc	2539	Bethlehem Energy Center	IPP Non-CHP	NY	5	CC1	194.3	182.6	203.9	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	NYIS	14
14294	PSEG Power New York Inc	2539	Bethlehem Energy Center	IPP Non-CHP	NY	6	CC1	194.3	166.6	187.9	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	NYIS	14
14294	PSEG Power New York Inc	2539	Bethlehem Energy Center	IPP Non-CHP	NY	7	CC1	194.3	182.6	203.9	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	NYIS	14
14294	PSEG Power New York Inc	2539	Bethlehem Energy Center	IPP Non-CHP	NY	8	CC1	310.2	257.0	296.6	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	NYIS	14
5416	Duke Energy Carolinas, LLC	2720	Buck	Electric Utility	NC	CT11	CC1	185.3	178.0	206.0	Natural Gas Fired Combined Cycle	NG	CT	11	2011	Operating	DUK	8
5416	Duke Energy Carolinas, LLC	2720	Buck	Electric Utility	NC	CT12	CC1	185.3	178.0	206.0	Natural Gas Fired Combined Cycle	NG	CT	11	2011	Operating	DUK	8
5416	Duke Energy Carolinas, LLC	2720	Buck	Electric Utility	NC	ST10	CC1	327.3	312.0	304.0	Natural Gas Fired Combined Cycle	NG	CA	11	2011	Operating	DUK	8
5416	Duke Energy Carolinas, LLC	2723	Dan River	Electric Utility	NC	CT8	CC1	185.3	171.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	DUK	7
5416	Duke Energy Carolinas, LLC	2723	Dan River	Electric Utility	NC	CT9	CC1	185.3	171.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	DUK	7
5416	Duke Energy Carolinas, LLC	2723	Dan River	Electric Utility	NC	ST7	CC1	327.3	320.0	320.0	Natural Gas Fired Combined Cycle	NG	CA	12	2012	Operating	DUK	7
15474	Public Service Co of Oklahoma	2963	Northeastern	Electric Utility	OK	1	NE1S	170.0	146.0	161.0	Natural Gas Fired Combined Cycle	NG	CA	4	1961	Operating	SWPP	58
15474	Public Service Co of Oklahoma	2963	Northeastern	Electric Utility	OK	1A	NE1S	178.5	149.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	SWPP	18
15474	Public Service Co of Oklahoma	2963	Northeastern	Electric Utility	OK	1B	NE1S	178.5	149.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	SWPP	18
20447	Western Farmers Elec Coop, Inc	3006	Anadarko Plant	Electric Utility	OK	4		105.1	94.0	94.0	Natural Gas Fired Combined Cycle	NG	CS	12	1977	Operating	SWPP	42
20447	Western Farmers Elec Coop, Inc	3006	Anadarko Plant	Electric Utility	OK	5		105.1	94.0	94.0	Natural Gas Fired Combined Cycle	NG	CS	11	1977	Operating	SWPP	42
20447	Western Farmers Elec Coop, Inc	3006	Anadarko Plant	Electric Utility	OK	6		105.1	94.0	94.0	Natural Gas Fired Combined Cycle	NG	CS	12	1977	Operating	SWPP	42
14165	NRG Power Midwest LP	3096	Brunot Island	IPP Non-CHP	PA	2A	BICC	65.3	46.0	54.0	Natural Gas Fired Combined Cycle	NG	CT	6	1973	Operating	PJM	46
14165	NRG Power Midwest LP	3096	Brunot Island	IPP Non-CHP	PA	2B	BICC	65.3	48.0	56.7	Natural Gas Fired Combined Cycle	NG	CT	6	1973	Operating	PJM	46
14165	NRG Power Midwest LP	3096	Brunot Island	IPP Non-CHP	PA	3	BICC	65.3	49.0	57.7	Natural Gas Fired Combined Cycle	NG	CT	6	1973	Operating	PJM	46
14165	NRG Power Midwest LP	3096	Brunot Island	IPP Non-CHP	PA	ST4	BICC	144.0	101.0	101.0	Natural Gas Fired Combined Cycle	NG	CA	7	1974	Operating	PJM	45
19391	UGI Development Co	3176	Hunlock Power Station	IPP Non-CHP	PA	3	HUN1	49.9	29.0	28.9	Natural Gas Fired Combined Cycle	NG	CA	9	1959	Operating	PJM	60
19391	UGI Development Co	3176	Hunlock Power Station	IPP Non-CHP	PA	5	HUN1	48.0	49.2	49.2	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	PJM	8
19391	UGI Development Co	3176	Hunlock Power Station	IPP Non-CHP	PA	6	HUN1	48.0	48.5	49.5	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	PJM	8
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	G10A	0321	125.0	110.1	115.6	Natural Gas Fired Combined Cycle	NG	CT	11	1995	Operating	ISNE	24
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	G11A	0322	125.0	110.2	115.6	Natural Gas Fired Combined Cycle	NG	CT	9	1995	Operating	ISNE	24
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	GE10	0321	48.0	46.9	54.4	Natural Gas Fired Combined Cycle	NG	CA	11	1995	Operating	ISNE	24
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	GE11	0322	46.0	46.8	54.4	Natural Gas Fired Combined Cycle	NG	CA	9	1995	Operating	ISNE	24
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	GE9A	0323	125.0	107.1	115.6	Natural Gas Fired Combined Cycle	NG	CT	11	1995	Operating	ISNE	24
50018	Dominion Energy New England, LLC	3236	Manchester Street	IPP Non-CHP	RI	GEN9	0323	46.0	46.9	54.5	Natural Gas Fired Combined Cycle	NG	CA	11	1995	Operating	ISNE	24
5416	Duke Energy Carolinas, LLC	3264	W S Lee	Electric Utility	SC	CT11	CC1	242.3	216.0	223.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	DUK	1
5416	Duke Energy Carolinas, LLC	3264	W S Lee	Electric Utility	SC	CT12	CC1	242.3	216.0	223.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	DUK	1
5416	Duke Energy Carolinas, LLC	3264	W S Lee	Electric Utility	SC	ST10	CC1	362.1	321.0	337.0	Natural Gas Fired Combined Cycle	NG	CA	4	2018	Operating	DUK	1
17539	South Carolina Electric&Gas Company	3295	Urquhart	Electric Utility	SC	1	UR15	75.0	64.0	65.0	Natural Gas Fired Combined Cycle	NG	CA	12	1953	Operating	SCEG	66
17539	South Carolina Electric&Gas Company	3295	Urquhart	Electric Utility	SC	2	UR26	75.0	64.0	66.0	Natural Gas Fired Combined Cycle	NG	CA	2	1954	Operating	SCEG	65
17539	South Carolina Electric&Gas Company	3295	Urquhart	Electric Utility	SC	CT1	UR15	198.9	162.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SCEG	17
17539	South Carolina Electric&Gas Company	3295	Urquhart	Electric Utility	SC	CT2	UR26	198.9	168.0	176.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SCEG	17
18642	Tennessee Valley Authority	3393	Allen	Electric Utility	TN	CTG1	CC1	347.0	311.9	330.3	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	TVA	1
18642	Tennessee Valley Authority	3393	Allen	Electric Utility	TN	CTG2	CC1	347.0	311.9	330.3	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	TVA	1
18642	Tennessee Valley Authority	3393	Allen	Electric Utility	TN	STG1	CC1	476.9	428.3	453.5	Natural Gas Fired Combined Cycle	NG	CA	4	2018	Operating	TVA	1
18642	Tennessee Valley Authority	3405	John Sevier	Electric Utility	TN	CTG1	CC1	191.3	165.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	4	2012	Operating	TVA	7

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
18642	Tennessee Valley Authority	3405	John Sevier	Electric Utility	TN	CTG2	CC1	191.3	165.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	4	2012	Operating	TVA	7
18642	Tennessee Valley Authority	3405	John Sevier	Electric Utility	TN	CTG3	CC1	191.3	165.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	4	2012	Operating	TVA	7
18642	Tennessee Valley Authority	3405	John Sevier	Electric Utility	TN	STG1	CC1	423.0	383.0	376.0	Natural Gas Fired Combined Cycle	NG	CA	4	2012	Operating	TVA	7
49979	Topaz Power Group GP II, LLC	3441	Nueces Bay	IPP Non-CHP	TX	7	CC1	351.0	319.0	325.0	Natural Gas Fired Combined Cycle	NG	CA	7	1972	Operating	ERCO	47
49979	Topaz Power Group GP II, LLC	3441	Nueces Bay	IPP Non-CHP	TX	8	CC1	189.6	157.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	3	2010	Operating	ERCO	9
49979	Topaz Power Group GP II, LLC	3441	Nueces Bay	IPP Non-CHP	TX	9	CC1	189.6	157.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	3	2010	Operating	ERCO	9
60638	Victoria WLE, LP	3443	Victoria	IPP Non-CHP	TX	5	CC1	180.0	125.0	132.0	Natural Gas Fired Combined Cycle	NG	CA	3	1963	Operating	ERCO	56
60638	Victoria WLE, LP	3443	Victoria	IPP Non-CHP	TX	7	CC1	196.9	160.0	171.0	Natural Gas Fired Combined Cycle	NG	CT	5	2009	Operating	ERCO	10
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	4	4CC	120.0	83.0	83.0	Natural Gas Fired Combined Cycle	NG	CA	8	1975	Operating	EPE	44
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	CT1	4CC	85.0	72.0	72.0	Natural Gas Fired Combined Cycle	NG	CT	8	1975	Operating	EPE	44
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	CT2	4CC	85.0	72.0	72.0	Natural Gas Fired Combined Cycle	NG	CT	8	1975	Operating	EPE	44
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	5CT1	5CC	86.5	70.0	70.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	EPE	10
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	5CT2	5CC	86.5	70.0	70.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	EPE	10
5701	El Paso Electric Co	3456	Newman	Electric Utility	TX	5CA1	5CC	165.0	141.9	155.1	Natural Gas Fired Combined Cycle	NG	CA	2	2011	Operating	EPE	8
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	31	THW3	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	32	THW3	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	33	THW3	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	34	THW3	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	41	THW4	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	42	THW4	54.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	7	1972	Operating	ERCO	47
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	3	THW3	113.1	104.0	104.0	Natural Gas Fired Combined Cycle	NG	CA	8	1974	Operating	ERCO	45
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	4	THW4	113.1	104.0	104.0	Natural Gas Fired Combined Cycle	NG	CA	8	1974	Operating	ERCO	45
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	43	THW4	56.7	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	ERCO	45
54888	NRG Texas Power LLC	3469	T H Wharton	IPP Non-CHP	TX	44	THW4	56.7	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	ERCO	45
2409	Brownsville Public Utilities Board	3559	Silas Ray	Electric Utility	TX	6	CC1	25.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	5	1959	Operating	ERCO	60
2409	Brownsville Public Utilities Board	3559	Silas Ray	Electric Utility	TX	9	CC1	50.0	42.0	52.0	Natural Gas Fired Combined Cycle	NG	CT	6	1996	Operating	ERCO	23
11292	City of Lubbock - (TX)	3604	J Robert Massengale	Electric Utility	TX	6A	MGL8	22.0	18.0	18.0	Natural Gas Fired Combined Cycle	NG	CA	6	1957	Operating	SWPP	62
11292	City of Lubbock - (TX)	3604	J Robert Massengale	Electric Utility	TX	7	MGL8	22.0	18.0	18.0	Natural Gas Fired Combined Cycle	NG	CA	3	1959	Operating	SWPP	60
11292	City of Lubbock - (TX)	3604	J Robert Massengale	Electric Utility	TX	8	MGL8	40.0	38.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	9	2000	Operating	SWPP	19
17583	South Texas Electric Coop, Inc	3631	Sam Rayburn	Electric Utility	TX	10	CC1	42.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CA	10	2003	Operating	ERCO	16
17583	South Texas Electric Coop, Inc	3631	Sam Rayburn	Electric Utility	TX	7	CC1	49.2	49.0	49.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	ERCO	16
17583	South Texas Electric Coop, Inc	3631	Sam Rayburn	Electric Utility	TX	8	CC1	49.2	49.0	49.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	ERCO	16
17583	South Texas Electric Coop, Inc	3631	Sam Rayburn	Electric Utility	TX	9	CC1	49.2	48.0	48.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	ERCO	16
19876	Virginia Electric & Power Co	3797	Chesterfield	Electric Utility	VA	CT7	CH7	145.0	142.0	166.0	Natural Gas Fired Combined Cycle	NG	CT	6	1990	Operating	PJM	29
19876	Virginia Electric & Power Co	3797	Chesterfield	Electric Utility	VA	CW7	CH7	74.4	55.0	60.0	Natural Gas Fired Combined Cycle	NG	CA	6	1990	Operating	PJM	29
19876	Virginia Electric & Power Co	3797	Chesterfield	Electric Utility	VA	CT8	CH8	148.0	140.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	5	1992	Operating	PJM	27
19876	Virginia Electric & Power Co	3797	Chesterfield	Electric Utility	VA	CW8	CH8	79.2	60.0	61.0	Natural Gas Fired Combined Cycle	NG	CA	5	1992	Operating	PJM	27
19876	Virginia Electric & Power Co	3804	Possum Point	Electric Utility	VA	6A	G784	174.0	148.5	176.5	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
19876	Virginia Electric & Power Co	3804	Possum Point	Electric Utility	VA	6B	G784	174.0	148.5	176.5	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
19876	Virginia Electric & Power Co	3804	Possum Point	Electric Utility	VA	6ST	G784	265.0	262.0	262.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	PJM	16
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	2CT1	PWG2	167.9	185.0	198.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	MISO	14
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	2CT2	PWG2	167.9	185.0	198.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	MISO	14
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	ST2	PWG2	268.6	240.0	249.0	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	MISO	14
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	1CT1	PWG1	167.9	162.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	MISO	11
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	1CT2	PWG1	167.9	162.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	MISO	11
20847	Wisconsin Electric Power Co	4040	Port Washington Generating Station	Electric Utility	WI	ST1	PWG1	268.6	248.0	242.0	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	MISO	11
11269	Lower Colorado River Authority	4937	Thomas C Ferguson	Electric Utility	TX	CT-1	CC1	185.3	168.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	ERCO	5
11269	Lower Colorado River Authority	4937	Thomas C Ferguson	Electric Utility	TX	CT-2	CC1	185.3	168.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	ERCO	5
11269	Lower Colorado River Authority	4937	Thomas C Ferguson	Electric Utility	TX	STG	CC1	204.0	180.0	194.0	Natural Gas Fired Combined Cycle	NG	CA	8	2014	Operating	ERCO	5
49979	Topaz Power Group GP II, LLC	4939	Barney M Davis	IPP Non-CHP	TX	2	CC1	351.0	319.0	325.0	Natural Gas Fired Combined Cycle	NG	CA	7	1976	Operating	ERCO	43

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
49979	Topaz Power Group GP II, LLC	4939	Barney M Davis	IPP Non-CHP	TX	3	CC1	189.6	157.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	3	2010	Operating	ERCO	9
49979	Topaz Power Group GP II, LLC	4939	Barney M Davis	IPP Non-CHP	TX	4	CC1	189.6	157.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	3	2010	Operating	ERCO	9
6452	Florida Power & Light Co	6042	Manatee	Electric Utility	FL	3	G341	471.8	1,111.0	1,187.0	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6042	Manatee	Electric Utility	FL	A	G341	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6042	Manatee	Electric Utility	FL	B	G341	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6042	Manatee	Electric Utility	FL	C	G341	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6042	Manatee	Electric Utility	FL	D	G341	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	3GT1	C796	204.0			Natural Gas Fired Combined Cycle	NG	CT	2	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	3GT2	C796	204.0			Natural Gas Fired Combined Cycle	NG	CT	2	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	3ST	C796	204.0	469.0	498.0	Natural Gas Fired Combined Cycle	NG	CA	2	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	4GT1	C797	204.0			Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	4GT2	C797	204.0			Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	4ST	C797	204.0	469.0	498.0	Natural Gas Fired Combined Cycle	NG	CA	4	1994	Operating	FPL	25
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	8A	G342	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	FPL	18
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	8B	G342	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	FPL	18
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	8	G342	471.7	1,105.0	1,180.0	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	8C	G342	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
6452	Florida Power & Light Co	6043	Martin	Electric Utility	FL	8D	G342	188.2			Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	FPL	14
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	3	0003	185.5	540.0	561.0	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	SOCO	18
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	3CT	0003	185.5			Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	SOCO	18
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	3ST	0003	195.2			Natural Gas Fired Combined Cycle	NG	CA	5	2001	Operating	SOCO	18
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	4	0004	185.5	552.0	585.0	Natural Gas Fired Combined Cycle	NG	CT	4	2001	Operating	SOCO	18
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	4CT	0004	185.5			Natural Gas Fired Combined Cycle	NG	CT	4	2001	Operating	SOCO	18
12686	Mississippi Power Co	6073	Victor J Daniel Jr	Electric Utility	MS	4ST	0004	195.2			Natural Gas Fired Combined Cycle	NG	CA	4	2001	Operating	SOCO	18
15466	Public Service Co of Colorado	6112	Fort St Vrain	Electric Utility	CO	2	FSV0	175.1	123.0	134.0	Natural Gas Fired Combined Cycle	NG	CT	5	1996	Operating	PSCO	23
15466	Public Service Co of Colorado	6112	Fort St Vrain	Electric Utility	CO	1	FSV0	342.6	301.0	304.0	Natural Gas Fired Combined Cycle	NG	CA	7	1998	Operating	PSCO	21
15466	Public Service Co of Colorado	6112	Fort St Vrain	Electric Utility	CO	3	FSV0	175.1	128.0	139.0	Natural Gas Fired Combined Cycle	NG	CT	1	1999	Operating	PSCO	20
15466	Public Service Co of Colorado	6112	Fort St Vrain	Electric Utility	CO	4	FSV0	175.1	128.0	139.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	PSCO	18
9130	Hutchinson Utilities Comm	6358	Hutchinson Plant #2	Electric Utility	MN	2	CC1	54.0	41.0	41.0	Natural Gas Fired Combined Cycle	NG	CT	11	1994	Operating	MISO	25
9130	Hutchinson Utilities Comm	6358	Hutchinson Plant #2	Electric Utility	MN	3	CC1	11.5	10.0	10.0	Natural Gas Fired Combined Cycle	NG	CA	11	1994	Operating	MISO	25
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	7	CC1	102.6	102.6	81.8	Natural Gas Fired Combined Cycle	NG	CT	6	1979	Operating		40
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	10	CC2	60.4	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	2	2017	Operating		2
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	11	CC2	30.9	29.0	29.0	Natural Gas Fired Combined Cycle	NG	CA	2	2017	Operating		2
599	Anchorage Municipal Light and Power	6559	George M Sullivan Generation Plant 2	Electric Utility	AK	9	CC2	60.4	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	2	2017	Operating		2
13407	Nevada Power Co	7082	Harry Allen	Electric Utility	NV	5	PB1	167.5	151.6	164.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	NEVP	8
13407	Nevada Power Co	7082	Harry Allen	Electric Utility	NV	6	PB1	167.5	151.6	164.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	NEVP	8
13407	Nevada Power Co	7082	Harry Allen	Electric Utility	NV	7	PB1	223.5	206.8	196.0	Natural Gas Fired Combined Cycle	NG	CA	5	2011	Operating	NEVP	8
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR1	CC1	122.0	126.0	126.0	Natural Gas Fired Combined Cycle	NG	CT	7	1989	Operating	PJM	30
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR2	CC1	122.0	126.0	126.0	Natural Gas Fired Combined Cycle	NG	CT	5	1989	Operating	PJM	30
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR3	CC1	122.0	126.0	126.0	Natural Gas Fired Combined Cycle	NG	CT	5	1991	Operating	PJM	28
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR4	CC1	200.0	187.0	187.0	Natural Gas Fired Combined Cycle	NG	CA	5	1993	Operating	PJM	26
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR5	CC2	144.0	128.0	128.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	PJM	18
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR6	CC2	144.0	128.0	128.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	PJM	18
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR7	CC2	144.0	128.0	128.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	PJM	18
56609	Calpine Mid-Atlantic Generation LLC	7153	Hay Road	IPP Non-CHP	DE	HR8	CC2	195.0	187.0	187.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	PJM	17
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	2	UN1	80.0	69.0	79.0	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	FMPP	24
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	2A	UN1	40.0	39.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	6	1995	Operating	FMPP	24
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	3	UN2	167.5	150.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	FMPP	17
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	3A	UN2	82.5	90.0	90.0	Natural Gas Fired Combined Cycle	NG	CA	1	2002	Operating	FMPP	17
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	4	UN3	180.0	160.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	FMPP	8

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
10376	Kissimmee Utility Authority	7238	Cane Island	Electric Utility	FL	4A	UN3	143.5	130.0	140.0	Natural Gas Fired Combined Cycle	NG	CA	7	2011	Operating	FMPP	8
18454	Tampa Electric Co	7242	Polk	Electric Utility	FL	2	CC2	175.8	150.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	Operating	TEC	19
18454	Tampa Electric Co	7242	Polk	Electric Utility	FL	3	CC2	175.8	150.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	TEC	17
18454	Tampa Electric Co	7242	Polk	Electric Utility	FL	4	CC2	175.8	150.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	3	2007	Operating	TEC	12
18454	Tampa Electric Co	7242	Polk	Electric Utility	FL	5	CC2	175.8	150.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	4	2007	Operating	TEC	12
18454	Tampa Electric Co	7242	Polk	Electric Utility	FL	2CC	CC2	463.0	461.0	480.0	Natural Gas Fired Combined Cycle	NG	CA	1	2017	Operating	TEC	2
12745	Modesto Irrigation District	7266	Woodland	Electric Utility	CA	2	CC1	37.7	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	BANC	16
12745	Modesto Irrigation District	7266	Woodland	Electric Utility	CA	3	CC1	60.5	48.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	BANC	16
15776	Reedy Creek Improvement Dist	7294	Central Energy Plant	Electric Utility	FL	GTG	CC01	61.5	48.0	48.0	Natural Gas Fired Combined Cycle	NG	CT	5	1989	of service	FPC	30
15776	Reedy Creek Improvement Dist	7294	Central Energy Plant	Electric Utility	FL	STG	CC01	8.5	8.0	8.0	Natural Gas Fired Combined Cycle	NG	CA	1	1989	Operating	FPC	30
5860	Empire District Electric Co	7296	State Line Combined Cycle	Electric Utility	MO	2-2	CC1	180.0	158.0	158.0	Natural Gas Fired Combined Cycle	NG	CT	6	1997	Operating	SWPP	22
5860	Empire District Electric Co	7296	State Line Combined Cycle	Electric Utility	MO	2-1	CC1	181.0	159.0	159.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	SWPP	18
5860	Empire District Electric Co	7296	State Line Combined Cycle	Electric Utility	MO	2-3	CC1	206.5	178.0	178.0	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	SWPP	18
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	1GT	E100	173.4	163.0	176.0	Natural Gas Fired Combined Cycle	NG	CT	4	1999	Operating	FPC	20
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	1GT2	E100	173.4	169.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	4	1999	Operating	FPC	20
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	1ST	E100	199.7	158.0	174.0	Natural Gas Fired Combined Cycle	NG	CA	4	1999	Operating	FPC	20
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	2GT	F110	167.7	166.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	FPC	16
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	2GT2	F110	167.7	174.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	FPC	16
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	2ST	F110	180.6	171.0	191.0	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	FPC	16
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	3GT	G301	193.0	173.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	11	2005	Operating	FPC	14
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	3GT2	G301	193.0	173.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	11	2005	Operating	FPC	14
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	3ST	G301	204.0	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CA	11	2005	Operating	FPC	14
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	4GT	H400	199.0	176.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	12	2007	Operating	FPC	12
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	4GT2	H400	199.0	175.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	12	2007	Operating	FPC	12
6455	Duke Energy Florida, LLC	7302	Hines Energy Complex	Electric Utility	FL	4ST	H400	212.5	165.0	177.0	Natural Gas Fired Combined Cycle	NG	CA	12	2007	Operating	FPC	12
15783	City of Redding - (CA)	7307	Redding Power	Electric Utility	CA	4	0101	26.8	27.0	28.0	Natural Gas Fired Combined Cycle	NG	CA	1	1989	Operating	BANC	30
15783	City of Redding - (CA)	7307	Redding Power	Electric Utility	CA	5	0101	40.0	41.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	BANC	17
15783	City of Redding - (CA)	7307	Redding Power	Electric Utility	CA	6	0101	42.5	41.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	8	2011	Operating	BANC	8
15296	New York Power Authority	7314	Richard M Flynn	Electric Utility	NY	NA1	CC1	108.0	87.5	103.9	Natural Gas Fired Combined Cycle	NG	CT	5	1994	Operating	NYIS	25
15248	Portland General Electric Co	7350	Coyote Springs	Electric Utility	OR	1	CC1	185.7	165.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	11	1995	Operating	PGE	24
15248	Portland General Electric Co	7350	Coyote Springs	Electric Utility	OR	2	CC1	80.6	70.0	74.0	Natural Gas Fired Combined Cycle	NG	CA	11	1995	Operating	PGE	24
21554	Seminole Electric Cooperative Inc	7380	Midulla Generating Station	Electric Utility	FL	CT1	CCU1	199.0	155.0	179.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	SEC	17
21554	Seminole Electric Cooperative Inc	7380	Midulla Generating Station	Electric Utility	FL	CT2	CCU1	199.0	155.0	179.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	SEC	17
21554	Seminole Electric Cooperative Inc	7380	Midulla Generating Station	Electric Utility	FL	ST3	CCU1	189.0	179.0	179.0	Natural Gas Fired Combined Cycle	NG	CA	1	2002	Operating	SEC	17
16604	City of San Antonio - (TX)	7512	Arthur Von Rosenberg	Electric Utility	TX	1	CC1	187.5	157.0	157.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
16604	City of San Antonio - (TX)	7512	Arthur Von Rosenberg	Electric Utility	TX	2	CC1	187.5	157.0	157.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
16604	City of San Antonio - (TX)	7512	Arthur Von Rosenberg	Electric Utility	TX	3	CC1	200.0	164.0	164.0	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	ERCO	19
16534	Sacramento Municipal Util Dist	7527	Carson Ice-Gen Project	Electric Utility	CA	2	CC1	17.5	16.6	16.6	Natural Gas Fired Combined Cycle	NG	CA	10	1995	Operating	BANC	24
16534	Sacramento Municipal Util Dist	7527	Carson Ice-Gen Project	Electric Utility	CA	CCCT	CC1	54.0	51.2	51.2	Natural Gas Fired Combined Cycle	NG	CT	10	1995	Operating	BANC	24
14077	Oklahoma Municipal Power Authority	7546	Ponca City	Electric Utility	OK	1	CC1	19.8	18.8	18.8	Natural Gas Fired Combined Cycle	NG	CA	10	1966	Operating	SWPP	53
14077	Oklahoma Municipal Power Authority	7546	Ponca City	Electric Utility	OK	3	CC1	54.0	44.1	44.1	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	SWPP	24
16534	Sacramento Municipal Util Dist	7551	SCA Cogen 2	Electric Utility	CA	CCST	CCC1	49.8	37.6	37.6	Natural Gas Fired Combined Cycle	NG	CA	3	1997	Operating	BANC	22
16534	Sacramento Municipal Util Dist	7551	SCA Cogen 2	Electric Utility	CA	CT1A	CCC1	49.8	47.6	47.6	Natural Gas Fired Combined Cycle	NG	CT	5	1997	Operating	BANC	22
16534	Sacramento Municipal Util Dist	7551	SCA Cogen 2	Electric Utility	CA	CT1B	CCC1	49.8	47.6	47.6	Natural Gas Fired Combined Cycle	NG	CT	3	1997	Operating	BANC	22
16534	Sacramento Municipal Util Dist	7552	SPA Cogen 3	Electric Utility	CA	CCCT	CCC1	118.7	111.0	111.0	Natural Gas Fired Combined Cycle	NG	CT	12	1997	Operating	BANC	22
16534	Sacramento Municipal Util Dist	7552	SPA Cogen 3	Electric Utility	CA	CCST	CCC1	55.2	53.0	53.0	Natural Gas Fired Combined Cycle	NG	CA	12	1997	Operating	BANC	22
924	Associated Electric Coop, Inc	7604	St Francis Energy Facility	Electric Utility	MO	1		253.3	204.0	208.0	Natural Gas Fired Combined Cycle	NG	CS	7	1999	Operating	AECI	20
924	Associated Electric Coop, Inc	7604	St Francis Energy Facility	Electric Utility	MO	2		253.3	216.0	235.0	Natural Gas Fired Combined Cycle	NG	CS	4	2001	Operating	AECI	18
3660	PUD No 1 of Clark County - (WA)	7605	River Road Gen Plant	Electric Utility	WA	1		248.0	220.0	248.0	Natural Gas Fired Combined Cycle	NG	CS	12	1997	Operating	BPAT	22
195	Alabama Power Co	7697	Facility	Electric Utility	AL	1	G523	82.6	75.0	82.0	Natural Gas Fired Combined Cycle	NG	CT	2	1999	Operating	SOCO	20

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
195	Alabama Power Co	7697	Facility	Electric Utility	AL	2	G523	39.9	25.0	25.0	Natural Gas Fired Combined Cycle	NG	CA	2	1999	Operating	SOCO	20
195	Alabama Power Co	7698	General Electric Plastic	Electric Utility	AL	1	G524	82.2	80.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	7	1999	Operating	SOCO	20
195	Alabama Power Co	7698	General Electric Plastic	Electric Utility	AL	2	G524	14.8	12.0	12.0	Natural Gas Fired Combined Cycle	NG	CA	7	1999	Operating	SOCO	20
6455	Duke Energy Florida, LLC	7699	Tiger Bay	Electric Utility	FL	CT1	G200	195.2	130.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	8	1997	Operating	FPC	22
6455	Duke Energy Florida, LLC	7699	Tiger Bay	Electric Utility	FL	CW1	G200	82.9	70.0	71.0	Natural Gas Fired Combined Cycle	NG	CA	8	1997	Operating	FPC	22
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT1A	G481	203.1	185.3	201.5	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT1B	G481	203.1	185.3	201.5	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT2A	G501	203.1	169.5	183.8	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT2B	G501	203.1	169.5	183.8	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	ST1	G481	213.3	213.0	213.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	ST2	G501	281.9	281.0	281.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	SOCO	17
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT3A	G100	203.1	188.6	204.1	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	SOCO	11
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	CT3B	G100	203.1	188.6	204.1	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	SOCO	11
17650	Southern Power Co	7710	H Allen Franklin Combined Cycle	IPP Non-CHP	AL	ST3	G100	281.9	281.0	281.0	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	SOCO	11
195	Alabama Power Co	7721	Theodore Cogen Facility	Electric Utility	AL	1	G525	229.0	166.3	180.3	Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	SOCO	19
195	Alabama Power Co	7721	Theodore Cogen Facility	Electric Utility	AL	2	G525	88.4	64.7	64.7	Natural Gas Fired Combined Cycle	NG	CA	12	2000	Operating	SOCO	19
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	1	CC1	176.0	141.0	157.0	Natural Gas Fired Combined Cycle	NG	CT	1	2000	Operating	AECI	19
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	2	CC1	176.0	143.0	156.0	Natural Gas Fired Combined Cycle	NG	CT	1	2000	Operating	AECI	19
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	3	CC1	182.8	137.0	140.0	Natural Gas Fired Combined Cycle	NG	CA	1	2000	Operating	AECI	19
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	4	CC2	176.0	157.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	6	2011	Operating	AECI	8
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	5	CC2	176.0	155.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	6	2011	Operating	AECI	8
924	Associated Electric Coop, Inc	7757	Chouteau	Electric Utility	OK	6	CC2	182.8	143.0	147.0	Natural Gas Fired Combined Cycle	NG	CA	6	2011	Operating	AECI	8
58651	Allegany Generating Station, LLC	7784	Allegany Cogen	IPP Non-CHP	NY	1	CC01	42.0	40.0	40.0	Natural Gas Fired Combined Cycle	NG	CT	6	1994	Operating	NYIS	25
58651	Allegany Generating Station, LLC	7784	Allegany Cogen	IPP Non-CHP	NY	2	CC01	25.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	6	1994	Operating	NYIS	25
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	7	1	199.4	154.0	189.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	CPLE	17
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	8	1	199.4	153.0	189.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	CPLE	17
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	ST4	1	195.5	169.0	175.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	CPLE	17
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	10	2	191.2	175.0	216.0	Natural Gas Fired Combined Cycle	NG	CT	6	2011	Operating	CPLE	8
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	9	2	191.2	174.0	216.0	Natural Gas Fired Combined Cycle	NG	CT	6	2011	Operating	CPLE	8
3046	Duke Energy Progress - (NC)	7805	Sherwood H Smith Jr Energy Complex	Electric Utility	NC	ST5	2	271.1	248.0	246.0	Natural Gas Fired Combined Cycle	NG	CA	6	2011	Operating	CPLE	8
17650	Southern Power Co	7826	Rowan	IPP Non-CHP	NC	4	G102	199.4	140.9	160.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	DUK	16
17650	Southern Power Co	7826	Rowan	IPP Non-CHP	NC	5	G102	199.4	140.9	160.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	DUK	16
17650	Southern Power Co	7826	Rowan	IPP Non-CHP	NC	STG	G102	195.0	195.0	195.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	DUK	16
17543	South Carolina Public Service Authority	7834	John S Rainey	Electric Utility	SC	CT1A	PB1	165.0	150.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	9	2001	Operating	SC	18
17543	South Carolina Public Service Authority	7834	John S Rainey	Electric Utility	SC	CT1B	PB1	165.0	150.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	9	2001	Operating	SC	18
17543	South Carolina Public Service Authority	7834	John S Rainey	Electric Utility	SC	ST1S	PB1	190.0	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CA	9	2001	Operating	SC	18
18642	Tennessee Valley Authority	7845	Lagoon Creek	Electric Utility	TN	CTG1	CC1	173.4	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	9	2010	Operating	TVA	9
18642	Tennessee Valley Authority	7845	Lagoon Creek	Electric Utility	TN	CTG2	CC1	173.4	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	9	2010	Operating	TVA	9
18642	Tennessee Valley Authority	7845	Lagoon Creek	Electric Utility	TN	STG1	CC1	257.6	205.0	235.0	Natural Gas Fired Combined Cycle	NG	CA	9	2010	Operating	TVA	9
9617	JEA	7846	Brandy Branch	Electric Utility	FL	002	CC1	185.0	158.6	191.2	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	JEA	18
9617	JEA	7846	Brandy Branch	Electric Utility	FL	003	CC1	185.0	158.6	191.2	Natural Gas Fired Combined Cycle	NG	CT	10	2001	Operating	JEA	18
9617	JEA	7846	Brandy Branch	Electric Utility	FL	004	CC1	228.1	185.0	190.0	Natural Gas Fired Combined Cycle	NG	CA	2	2005	Operating	JEA	14
15500	Puget Sound Energy Inc	7870	Encogen	Electric Utility	WA	CTG1	CC1	39.4	34.5	42.2	Natural Gas Fired Combined Cycle	NG	CT	3	1993	Operating	PSEI	26
15500	Puget Sound Energy Inc	7870	Encogen	Electric Utility	WA	CTG2	CC1	39.4	34.5	42.2	Natural Gas Fired Combined Cycle	NG	CT	3	1993	Operating	PSEI	26
15500	Puget Sound Energy Inc	7870	Encogen	Electric Utility	WA	CTG3	CC1	39.4	34.5	42.2	Natural Gas Fired Combined Cycle	NG	CT	3	1993	Operating	PSEI	26
15500	Puget Sound Energy Inc	7870	Encogen	Electric Utility	WA	STG	CC1	58.2	55.9	55.9	Natural Gas Fired Combined Cycle	NG	CA	4	1993	Operating	PSEI	26
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	1ST	CC1	239.4	233.0	243.0	Natural Gas Fired Combined Cycle	NG	CA	11	1965	Operating	TEC	54
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	1A	CC1	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	TEC	16
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	1B	CC1	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	TEC	16
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	1C	CC1	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	TEC	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	2ST	CC2	445.7	305.0	315.0	Natural Gas Fired Combined Cycle	NG	CA	10	1967	Operating	TEC	52
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	2A	CC2	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	TEC	15
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	2B	CC2	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	TEC	15
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	2C	CC2	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	TEC	15
18454	Tampa Electric Co	7873	H L Culbreath Bayside Power Station	Electric Utility	FL	2D	CC2	189.9	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	TEC	15
11018	Lincoln Electric System	7887	Terry Bundy Generating Station	Electric Utility	NE	2	CC1	60.5	47.0	48.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	SWPP	16
11018	Lincoln Electric System	7887	Terry Bundy Generating Station	Electric Utility	NE	1	CC1	28.2	28.6	28.6	Natural Gas Fired Combined Cycle	NG	CA	8	2004	Operating	SWPP	15
11018	Lincoln Electric System	7887	Terry Bundy Generating Station	Electric Utility	NE	3	CC1	60.5	47.0	48.0	Natural Gas Fired Combined Cycle	NG	CT	4	2004	Operating	SWPP	15
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	CT1A	G103	185.0	172.8	186.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SOCO	16
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	CT1B	G103	185.0	172.8	186.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SOCO	16
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	CT2A	G104	185.0	183.3	202.7	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SOCO	16
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	CT2B	G104	185.0	183.3	202.7	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SOCO	16
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	ST1	G103	282.0	282.0	282.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SOCO	16
17650	Southern Power Co	7897	E B Harris Electric Generating Plant	IPP Non-CHP	AL	ST2	G104	282.0	282.0	282.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SOCO	16
1015	Austin Energy	7900	Sand Hill	Electric Utility	TX	5A	CC1	198.0	161.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	9	2004	Operating	ERCO	15
1015	Austin Energy	7900	Sand Hill	Electric Utility	TX	5C	CC1	190.0	151.0	164.0	Natural Gas Fired Combined Cycle	NG	CA	9	2004	Operating	ERCO	15
13994	Oglethorpe Power Corporation	7917	Chattahoochee Energy Facility	Electric Utility	GA	1	2224	176.0	142.8	162.7	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	SOCO	16
13994	Oglethorpe Power Corporation	7917	Chattahoochee Energy Facility	Electric Utility	GA	2	2224	176.0	149.1	165.2	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	SOCO	16
13994	Oglethorpe Power Corporation	7917	Chattahoochee Energy Facility	Electric Utility	GA	3	2224	187.7	166.0	167.0	Natural Gas Fired Combined Cycle	NG	CA	2	2003	Operating	SOCO	16
20169	Avista Corp	7931	Coyote Springs II	Electric Utility	OR	1	U2CT	170.0	173.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	BPAT	16
20169	Avista Corp	7931	Coyote Springs II	Electric Utility	OR	2	U2CT	117.0	117.0	117.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	BPAT	16
13100	Municipal Electric Authority	7946	Wansley Unit 9	Electric Utility	GA	CT1	CC1	183.6	148.6	181.9	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	SOCO	15
13100	Municipal Electric Authority	7946	Wansley Unit 9	Electric Utility	GA	CT2	CC1	183.6	147.0	180.3	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	SOCO	15
13100	Municipal Electric Authority	7946	Wansley Unit 9	Electric Utility	GA	ST1	CC1	226.9	199.8	214.0	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	SOCO	15
12341	MidAmerican Energy Co	7985	Greater Des Moines	Electric Utility	IA	GT1	CC1	190.4	159.1	198.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
12341	MidAmerican Energy Co	7985	Greater Des Moines	Electric Utility	IA	GT2	CC1	190.4	156.9	197.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
12341	MidAmerican Energy Co	7985	Greater Des Moines	Electric Utility	IA	ST1	CC1	195.5	176.6	175.0	Natural Gas Fired Combined Cycle	NG	CA	12	2004	Operating	MISO	15
11479	Madison Gas & Electric Co	7991	West Campus Cogeneration Facility	Electric Utility	WI	1	CC1	54.0	30.9	30.9	Natural Gas Fired Combined Cycle	NG	CT	4	2005	Operating	MISO	14
11479	Madison Gas & Electric Co	7991	West Campus Cogeneration Facility	Electric Utility	WI	CT2	CC1	54.0	31.0	31.0	Natural Gas Fired Combined Cycle	NG	CT	4	2005	Operating	MISO	14
11479	Madison Gas & Electric Co	7991	West Campus Cogeneration Facility	Electric Utility	WI	STG1	CC1	61.3	65.0	65.0	Natural Gas Fired Combined Cycle	NG	CA	4	2005	Operating	MISO	14
49893	Invenergy Services LLC	7999	Grays Harbor Energy Facility	IPP Non-CHP	WA	CT1	CC01	198.9	151.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	BPAT	11
49893	Invenergy Services LLC	7999	Grays Harbor Energy Facility	IPP Non-CHP	WA	CT2	CC01	198.9	153.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	BPAT	11
49893	Invenergy Services LLC	7999	Grays Harbor Energy Facility	IPP Non-CHP	WA	ST1	CC01	300.0	300.0	314.0	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	BPAT	11
13337	Nebraska Public Power District	8000	Beatrice	Electric Utility	NE	CT1	CC1	76.6	69.0	69.0	Natural Gas Fired Combined Cycle	NG	CT	1	2005	Operating	SWPP	14
13337	Nebraska Public Power District	8000	Beatrice	Electric Utility	NE	CT2	CC1	76.6	68.0	68.0	Natural Gas Fired Combined Cycle	NG	CT	1	2005	Operating	SWPP	14
13337	Nebraska Public Power District	8000	Beatrice	Electric Utility	NE	ST1	CC1	93.9	83.0	83.0	Natural Gas Fired Combined Cycle	NG	CA	1	2005	Operating	SWPP	14
9417	Interstate Power and Light Co	8031	Emery Station	Electric Utility	IA	11	G821	173.4	135.3	162.4	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	MISO	15
9417	Interstate Power and Light Co	8031	Emery Station	Electric Utility	IA	12	G821	173.4	139.0	166.7	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	MISO	15
9417	Interstate Power and Light Co	8031	Emery Station	Electric Utility	IA	ST1	G821	256.0	228.7	255.9	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	MISO	15
15474	Public Service Co of Oklahoma	8059	Comanche (OK)	Electric Utility	OK	1G1	CC1	85.0	78.0	78.0	Natural Gas Fired Combined Cycle	NG	CT	12	1973	Operating	SWPP	46
15474	Public Service Co of Oklahoma	8059	Comanche (OK)	Electric Utility	OK	1G2	CC1	85.0	78.0	78.0	Natural Gas Fired Combined Cycle	NG	CT	8	1973	Operating	SWPP	46
15474	Public Service Co of Oklahoma	8059	Comanche (OK)	Electric Utility	OK	1S	CC1	120.0	104.0	114.0	Natural Gas Fired Combined Cycle	NG	CA	2	1974	Operating	SWPP	45
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST1		103.5	92.0	103.0	Natural Gas Fired Combined Cycle	NG	CS	10	1974	Operating	SRP	45
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST2		103.5	92.0	103.0	Natural Gas Fired Combined Cycle	NG	CS	12	1974	Operating	SRP	45
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST3		103.5	92.0	103.0	Natural Gas Fired Combined Cycle	NG	CS	10	1974	Operating	SRP	45
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST4		103.5	92.0	103.0	Natural Gas Fired Combined Cycle	NG	CS	5	1975	Operating	SRP	44
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST5A	STS5	153.8	151.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	4	2005	Operating	SRP	14
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST5B	STS5	153.8	151.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	4	2005	Operating	SRP	14
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST5S	STS5	314.5	280.0	286.0	Natural Gas Fired Combined Cycle	NG	CA	4	2005	Operating	SRP	14
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST6A	STS6	153.8	151.0	166.0	Natural Gas Fired Combined Cycle	NG	CT	3	2006	Operating	SRP	13

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
16572	Salt River Project	8068	Santan	Electric Utility	AZ	ST6S	STS6	136.1	126.0	135.0	Natural Gas Fired Combined Cycle	NG	CA	3	2006	Operating	SRP	13
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	1	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	2	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	3	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	4	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	5	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	6	CC1	68.3	54.0	60.0	Natural Gas Fired Combined Cycle	NG	CT	8	1974	Operating	PGE	45
15248	Portland General Electric Co	8073	Beaver	Electric Utility	OR	7	CC1	176.4	137.0	139.0	Natural Gas Fired Combined Cycle	NG	CA	11	1977	Operating	PGE	42
7860	NRG Energy Center Dover LLC	10030	NRG Energy Center Dover	IPP CHP	DE	COG1	CC1	18.0	16.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	5	1985	Operating	PJM	34
7860	NRG Energy Center Dover LLC	10030	NRG Energy Center Dover	IPP CHP	DE	KD-1	CC1	50.0	44.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	PJM	18
3028	Calpine Gilroy Cogen LP	10034	Gilroy Power Plant	IPP CHP	CA	GEN1	CC1	90.0	85.0	85.0	Natural Gas Fired Combined Cycle	NG	CT	10	1987	Operating	CISO	32
3028	Calpine Gilroy Cogen LP	10034	Gilroy Power Plant	IPP CHP	CA	GEN2	CC1	40.0	30.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	10	1987	Operating	CISO	32
11401	Mars Wrigley Confectionery US, LLC	10061	Mars Wrigley Confectionery US, LLC	Industrial CHP	NJ	GEN2	CC1	1.4	0.7	1.2	Natural Gas Fired Combined Cycle	NG	CA	10	1984	of service	PJM	35
11401	Mars Wrigley Confectionery US, LLC	10061	Mars Wrigley Confectionery US, LLC	Industrial CHP	NJ	GEN1	CC1	8.8	10.0	7.5	Natural Gas Fired Combined Cycle	NG	CT	5	1989	Operating	PJM	30
50160	Pedricktown Cogeneration Company LP	10099	LP	IPP Non-CHP	NJ	GEN1	CC1	92.1	115.3	115.1	Natural Gas Fired Combined Cycle	NG	CT	3	1992	Operating	PJM	27
50160	Pedricktown Cogeneration Company LP	10099	LP	IPP Non-CHP	NJ	GEN2	CC1	42.4			Natural Gas Fired Combined Cycle	NG	CA	3	1992	Operating	PJM	27
20323	Wellhead Energy, LLC	10156	Fresno Cogen Partners	IPP CHP	CA	GEN2	CC1	10.0	6.0	6.5	Natural Gas Fired Combined Cycle	NG	CA	1	1990	Operating	CISO	29
20323	Wellhead Energy, LLC	10156	Fresno Cogen Partners	IPP CHP	CA	GEN4	CC1	50.3	45.0	50.3	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	CISO	15
3084	Carson Cogeneration Co	10169	Carson Cogeneration	IPP CHP	CA	GEN1	CC1	45.3	41.3	41.1	Natural Gas Fired Combined Cycle	NG	CT	12	1989	Operating	CISO	30
3084	Carson Cogeneration Co	10169	Carson Cogeneration	IPP CHP	CA	GEN2	CC1	10.5	8.0	8.1	Natural Gas Fired Combined Cycle	NG	CA	1	1990	Operating	CISO	29
12632	Minnesota Mining & Mfg Co	10184	Central Utility Plant	Commercial CHP	TX	EG1	1	6.0	2.6	3.0	Natural Gas Fired Combined Cycle	NG	CT	7	1988	Operating	ERCO	31
12632	Minnesota Mining & Mfg Co	10184	Central Utility Plant	Commercial CHP	TX	EG2	1	6.0	3.4	2.7	Natural Gas Fired Combined Cycle	NG	CT	7	1988	Operating	ERCO	31
12632	Minnesota Mining & Mfg Co	10184	Central Utility Plant	Commercial CHP	TX	TG1	1	2.3	2.2	2.3	Natural Gas Fired Combined Cycle	NG	CA	7	1988	Operating	ERCO	31
60741	Fortistar Castleton Power	10190	Castleton Energy Center	IPP Non-CHP	NY	GEN1	CCCC	47.0	70.2	78.7	Natural Gas Fired Combined Cycle	NG	CT	2	1992	Operating	NYIS	27
60741	Fortistar Castleton Power	10190	Castleton Energy Center	IPP Non-CHP	NY	GEN2	CCCC	25.0	0.0	0.0	Natural Gas Fired Combined Cycle	NG	CA	2	1992	Operating	NYIS	27
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN1	CC1	42.4	38.7	38.7	Natural Gas Fired Combined Cycle	NG	CT	12	1987	Operating	CISO	32
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN2	CC1	42.4	38.7	38.7	Natural Gas Fired Combined Cycle	NG	CT	12	1987	Operating	CISO	32
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN5	CC1	40.3	39.2	39.2	Natural Gas Fired Combined Cycle	NG	CT	3	1996	Operating	CISO	23
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN6	CC1	9.1	9.1	9.1	Natural Gas Fired Combined Cycle	NG	CA	3	1996	Operating	CISO	23
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN7	CC1	40.7	40.7	40.7	Natural Gas Fired Combined Cycle	NG	CT	6	2013	Operating	CISO	6
3452	Chevron USA Inc-El Segundo	10213	El Segundo Cogen	Industrial CHP	CA	GEN8	CC1	5.2	5.2	5.2	Natural Gas Fired Combined Cycle	NG	CA	6	2013	Operating	CISO	6
2848	California Institute-Technology	10262	California Institute of Technology	Commercial CHP	CA	GEN6	CC1	10.5	9.0	9.9	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	CISO	16
2848	California Institute-Technology	10262	California Institute of Technology	Commercial CHP	CA	GEN7	CC1	2.5	2.1	2.1	Natural Gas Fired Combined Cycle	NG	CA	10	2003	Operating	CISO	16
2938	Calpine King City Cogen LLC	10294	King City Power Plant	IPP CHP	CA	GTG	CC01	90.8	73.0	83.5	Natural Gas Fired Combined Cycle	NG	CT	2	1989	Operating	CISO	30
2938	Calpine King City Cogen LLC	10294	King City Power Plant	IPP CHP	CA	STG	CC01	42.4	38.0	39.0	Natural Gas Fired Combined Cycle	NG	CA	3	1989	Operating	CISO	30
21970	Northeast Energy Associates LP	10307	Bellingham Cogeneration Facility	IPP Non-CHP	MA	CT1	CC1	128.7	102.0	126.0	Natural Gas Fired Combined Cycle	NG	CT	9	1991	Operating	ISNE	28
21970	Northeast Energy Associates LP	10307	Bellingham Cogeneration Facility	IPP Non-CHP	MA	CT2	CC1	128.7	102.0	126.0	Natural Gas Fired Combined Cycle	NG	CT	9	1991	Operating	ISNE	28
21970	Northeast Energy Associates LP	10307	Bellingham Cogeneration Facility	IPP Non-CHP	MA	ST1	CC1	128.7	60.0	84.0	Natural Gas Fired Combined Cycle	NG	CA	9	1991	Operating	ISNE	28
22290	North Jersey Energy Assoc LP	10308	Sayreville Cogeneration Facility	IPP Non-CHP	NJ	CT1	CC1	143.4	112.0	127.8	Natural Gas Fired Combined Cycle	NG	CT	8	1991	Operating	PJM	28
22290	North Jersey Energy Assoc LP	10308	Sayreville Cogeneration Facility	IPP Non-CHP	NJ	CT2	CC1	143.4	112.0	127.8	Natural Gas Fired Combined Cycle	NG	CT	8	1991	Operating	PJM	28
22290	North Jersey Energy Assoc LP	10308	Sayreville Cogeneration Facility	IPP Non-CHP	NJ	ST1	CC1	143.4	68.0	77.5	Natural Gas Fired Combined Cycle	NG	CA	8	1991	Operating	PJM	28
6659	Foster Wheeler Power Sys Inc	10342	Foster Wheeler Martinez	IPP CHP	CA	TG1	CC1	40.0	35.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	2	1987	Operating	CISO	32
6659	Foster Wheeler Power Sys Inc	10342	Foster Wheeler Martinez	IPP CHP	CA	TG2	CC1	40.0	35.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	2	1987	Operating	CISO	32
6659	Foster Wheeler Power Sys Inc	10342	Foster Wheeler Martinez	IPP CHP	CA	TG3	CC1	33.5	33.5	33.5	Natural Gas Fired Combined Cycle	NG	CA	2	1987	Operating	CISO	32
59879	Greenleaf Energy LLC	10350	Greenleaf 1 Power Plant	IPP CHP	CA	GEN1	CC1	46.0	42.0	44.0	Natural Gas Fired Combined Cycle	NG	CT	2	1989	Operating	CISO	30
59879	Greenleaf Energy LLC	10350	Greenleaf 1 Power Plant	IPP CHP	CA	GEN2	CC1	20.0	8.0	6.0	Natural Gas Fired Combined Cycle	NG	CA	2	1989	Operating	CISO	30
10337	KES Kingsburg LP	10405	Kingsburg Cogen	IPP CHP	CA	GEN1	CC1	23.1	22.0	23.0	Natural Gas Fired Combined Cycle	NG	CT	12	1990	Operating	CISO	29
10337	KES Kingsburg LP	10405	Kingsburg Cogen	IPP CHP	CA	GEN2	CC1	13.1	11.8	11.8	Natural Gas Fired Combined Cycle	NG	CA	12	1990	Operating	CISO	29
11216	Los Angeles County	10478	Pitchess Cogen Station	Commercial CHP	CA	GEN1	CC1	20.9	21.5	20.9	Natural Gas Fired Combined Cycle	NG	CT	9	1988	Operating	CISO	31
11216	Los Angeles County	10478	Pitchess Cogen Station	Commercial CHP	CA	GEN2	CC1	7.4	5.7	6.0	Natural Gas Fired Combined Cycle	NG	CA	9	1988	Operating	CISO	31

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
60641	Veolia NA - Municipal & Commercial Business	10521	Lederle Laboratories	Industrial CHP	NY	GEN3	CC1	2.2	2.2	2.2	Natural Gas Fired Combined Cycle	NG	CA	7	1990	Operating	NYIS	29
60641	Veolia NA - Municipal & Commercial Business	10521	Lederle Laboratories	Industrial CHP	NY	GEN1	CC1	8.3	8.3	8.3	Natural Gas Fired Combined Cycle	NG	CT	1	1991	Operating	NYIS	28
60641	Veolia NA - Municipal & Commercial Business	10521	Lederle Laboratories	Industrial CHP	NY	GEN2	CC1	8.3	8.3	8.3	Natural Gas Fired Combined Cycle	NG	CT	1	1991	Operating	NYIS	28
60641	Veolia NA - Municipal & Commercial Business	10521	Lederle Laboratories	Industrial CHP	NY	TG4	CC1	3.1	1.4	1.4	Natural Gas Fired Combined Cycle	NG	CA	7	1997	Operating	NYIS	22
60641	Veolia NA - Municipal & Commercial Business	10521	Lederle Laboratories	Industrial CHP	NY	3A	CC1	1.5	1.5	1.5	Natural Gas Fired Combined Cycle	NG	CA	12	1998	Operating	NYIS	21
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	BO3	CHP1	36.2	32.0	32.0	Natural Gas Fired Combined Cycle	NG	CT	3	1987	Operating	ERCO	32
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG1	CHP1	82.5	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	4	1993	Operating	ERCO	26
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG2	CHP1	82.5	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	ERCO	26
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG3	CHP1	82.5	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	9	1993	Operating	ERCO	26
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	ST1	CHP1	33.5	28.5	28.5	Natural Gas Fired Combined Cycle	NG	CA	3	1994	Operating	ERCO	25
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	ST2	CHP1	66.3	57.5	57.5	Natural Gas Fired Combined Cycle	NG	CA	3	1994	Operating	ERCO	25
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG4	CHP1	82.5	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	5	1994	Operating	ERCO	25
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG5	CHP1	82.5	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	10	1994	Operating	ERCO	25
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	ST3	CHP1	55.0	47.3	51.7	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	ERCO	17
6541	Formosa Plastics Corp	10554	Formosa Utility Venture Ltd	Industrial CHP	TX	TBG6	CHP1	85.9	72.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	ERCO	16
291	Algonquin Windsor Locks LLC	10567	Algonquin Windsor Locks	IPP CHP	CT	GTG	CC1	40.0	35.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	1	1990	Operating	ISNE	29
291	Algonquin Windsor Locks LLC	10567	Algonquin Windsor Locks	IPP CHP	CT	STG	CC1	16.0	16.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	1	1990	Operating	ISNE	29
291	Algonquin Windsor Locks LLC	10567	Algonquin Windsor Locks	IPP CHP	CT	GTG2	CC1	15.0	13.0	15.0	Natural Gas Fired Combined Cycle	NG	CT	7	2012	Operating	ISNE	7
58338	Lakeside Beaver Falls LLC	10617	CH Resources Beaver Falls	IPP CHP	NY	GEN1	CC01	65.5	50.8	63.9	Natural Gas Fired Combined Cycle	NG	CT	4	1995	Operating	NYIS	24
58338	Lakeside Beaver Falls LLC	10617	CH Resources Beaver Falls	IPP CHP	NY	GEN2	CC01	42.3	30.6	31.8	Natural Gas Fired Combined Cycle	NG	CA	4	1995	Operating	NYIS	24
3085	Carthage Energy LLC	10620	Carthage Energy LLC	IPP Non-CHP	NY	GEN1	CC1	40.9	38.2	44.7	Natural Gas Fired Combined Cycle	NG	CT	11	1991	Operating	NYIS	28
3085	Carthage Energy LLC	10620	Carthage Energy LLC	IPP Non-CHP	NY	GEN2	CC1	22.0	21.0	21.5	Natural Gas Fired Combined Cycle	NG	CA	11	1991	Operating	NYIS	28
58337	Lakeside Syracuse LLC	10621	CH Resources Syracuse	IPP Non-CHP	NY	GEN1	CC01	65.5	55.9	63.0	Natural Gas Fired Combined Cycle	NG	CT	1	1994	Operating	NYIS	25
58337	Lakeside Syracuse LLC	10621	CH Resources Syracuse	IPP Non-CHP	NY	GEN2	CC01	37.2	28.8	28.8	Natural Gas Fired Combined Cycle	NG	CA	1	1994	Operating	NYIS	25
11216	Los Angeles County	10623	Civic Center	Commercial CHP	CA	GEN1	CC1	22.1	22.1	22.1	Natural Gas Fired Combined Cycle	NG	CT	8	1989	Operating	LDWP	30
11216	Los Angeles County	10623	Civic Center	Commercial CHP	CA	GEN2	CC1	12.4	1.5	0.5	Natural Gas Fired Combined Cycle	NG	CA	8	1989	Operating	LDWP	30
19091	GDF Suez NA - Hopewell	10633	Hopewell Cogeneration	IPP CHP	VA	GT1	CC1	101.0	94.1	101.0	Natural Gas Fired Combined Cycle	NG	CT	1	1990	Operating	PJM	29
19091	GDF Suez NA - Hopewell	10633	Hopewell Cogeneration	IPP CHP	VA	GT2	CC1	101.0	94.1	101.0	Natural Gas Fired Combined Cycle	NG	CT	2	1990	Operating	PJM	29
19091	GDF Suez NA - Hopewell	10633	Hopewell Cogeneration	IPP CHP	VA	GT3	CC1	101.0	94.1	101.0	Natural Gas Fired Combined Cycle	NG	CT	3	1990	Operating	PJM	29
19091	GDF Suez NA - Hopewell	10633	Hopewell Cogeneration	IPP CHP	VA	ST1	CC1	96.0	96.0	96.0	Natural Gas Fired Combined Cycle	NG	CA	3	1990	Operating	PJM	29
178	CES Placerita Inc	10677	CES Placerita Power Plant	IPP Non-CHP	CA	UNT2	CESP	60.0	46.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	6	1988	of service	CISO	31
178	CES Placerita Inc	10677	CES Placerita Power Plant	IPP Non-CHP	CA	UNT3	CESP	30.0	23.0	25.0	Natural Gas Fired Combined Cycle	NG	CA	6	1988	of service	CISO	31
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	GT1	CPP	23.8	25.0	30.0	Natural Gas Fired Combined Cycle	NG	CT	10	1990	Operating	PSCO	29
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	ST1	CPP	38.0	30.0	30.0	Natural Gas Fired Combined Cycle	NG	CA	10	1990	Operating	PSCO	29
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	GT3	BCP	37.0	32.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	1	1994	Operating	PSCO	25
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	ST2	BCP	37.0	40.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	1	1994	Operating	PSCO	25
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	GT4	BIV	23.8	25.0	30.0	Natural Gas Fired Combined Cycle	NG	CT	6	1999	Operating	PSCO	20
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	GT5	BIV	23.8	25.0	30.0	Natural Gas Fired Combined Cycle	NG	CT	6	1999	Operating	PSCO	20
55307	Colorado Energy Management	10682	Brush Generation Facility	IPP Non-CHP	CO	ST4	BIV	90.0	90.0	90.0	Natural Gas Fired Combined Cycle	NG	CA	9	2002	Operating	PSCO	17
16909	Selkirk Cogen Partners LP	10725	Selkirk Cogen	IPP CHP	NY	GEN1	F801	95.2	78.1	104.3	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NYIS	27
16909	Selkirk Cogen Partners LP	10725	Selkirk Cogen	IPP CHP	NY	GEN2	F801	12.0			Natural Gas Fired Combined Cycle	NG	CA	4	1992	Standby/	NYIS	27
16909	Selkirk Cogen Partners LP	10725	Selkirk Cogen	IPP CHP	NY	GEN3	F802	95.2	282.1	325.9	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	NYIS	25
16909	Selkirk Cogen Partners LP	10725	Selkirk Cogen	IPP CHP	NY	GEN4	F802	95.2			Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	NYIS	25
16909	Selkirk Cogen Partners LP	10725	Selkirk Cogen	IPP CHP	NY	GEN5	F802	148.4			Natural Gas Fired Combined Cycle	NG	CA	4	1994	Operating	NYIS	25
11741	Masspower	10726	Masspower	IPP CHP	MA	GEN1	G321	90.0	83.0	95.0	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	ISNE	26
11741	Masspower	10726	Masspower	IPP CHP	MA	GEN2	G321	90.0	83.0	95.0	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	ISNE	26
11741	Masspower	10726	Masspower	IPP CHP	MA	GEN3	G321	80.9	79.0	90.0	Natural Gas Fired Combined Cycle	NG	CA	7	1993	Operating	ISNE	26
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT3	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	6	1989	Operating	MISO	30
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT4	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	8	1989	Operating	MISO	30
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT5	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	9	1989	Operating	MISO	30

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT6	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	10	1989	Operating	MISO	30
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT7	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	9	1989	Operating	MISO	30
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT8	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	12	1989	Operating	MISO	30
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT10	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	1	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT11	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	2	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT12	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	3	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT13	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	4	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT14	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	5	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	GT9	1	87.1	88.0	103.0	Natural Gas Fired Combined Cycle	NG	CT	1	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	ST1	1	410.0	410.0	410.0	Natural Gas Fired Combined Cycle	NG	CA	2	1990	Operating	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	ST2	1	380.0	380.0	380.0	Natural Gas Fired Combined Cycle	NG	CA	9	1990	Standby/	MISO	29
12492	Midland Cogeneration Venture	10745	Midland Cogeneration Venture	IPP CHP	MI	BP15	1	13.4	13.4	13.4	Natural Gas Fired Combined Cycle	NG	CA	7	1998	Operating	MISO	21
56516	Morris Energy Operations Company, LLC	10751	Camden Plant Holding LLC	IPP Non-CHP	NJ	GEN1	CC1	95.2	145.0	144.7	Natural Gas Fired Combined Cycle	NG	CT	2	1993	Operating	PJM	26
56516	Morris Energy Operations Company, LLC	10751	Camden Plant Holding LLC	IPP Non-CHP	NJ	GEN2	CC1	61.8			Natural Gas Fired Combined Cycle	NG	CA	2	1993	Operating	PJM	26
30151	Tri-State G & T Assn, Inc	10755	Rifle Generating Station	Electric Utility	CO	GT2	CC1	15.0	13.0	15.0	Natural Gas Fired Combined Cycle	NG	CT	8	1987	Operating	PSCO	32
30151	Tri-State G & T Assn, Inc	10755	Rifle Generating Station	Electric Utility	CO	GT3	CC1	15.0	13.0	15.0	Natural Gas Fired Combined Cycle	NG	CT	8	1987	Operating	PSCO	32
30151	Tri-State G & T Assn, Inc	10755	Rifle Generating Station	Electric Utility	CO	GT4	CC1	15.0	13.0	15.0	Natural Gas Fired Combined Cycle	NG	CT	8	1987	Operating	PSCO	32
30151	Tri-State G & T Assn, Inc	10755	Rifle Generating Station	Electric Utility	CO	ST1	CC1	39.0	34.0	34.8	Natural Gas Fired Combined Cycle	NG	CA	8	1987	Operating	PSCO	32
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN1	CCB1	49.8	41.0	43.0	Natural Gas Fired Combined Cycle	NG	CT	3	1994	Operating	NEVP	25
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN2	CCB1	11.5	9.0	10.0	Natural Gas Fired Combined Cycle	NG	CA	4	1994	Operating	NEVP	25
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN3	CCB2	60.5	45.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	NEVP	16
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN4	CCB2	60.5	45.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	NEVP	16
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN5	CCB3	60.5	45.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	NEVP	16
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN6	CCB3	60.5	45.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	NEVP	16
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN7	CCB2	27.8	26.0	26.0	Natural Gas Fired Combined Cycle	NG	CA	1	2003	Operating	NEVP	16
13407	Nevada Power Co	10761	Las Vegas Generating Station	Electric Utility	NV	GEN8	CCB3	27.8	26.0	26.0	Natural Gas Fired Combined Cycle	NG	CA	1	2003	Operating	NEVP	16
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	GEN3	CCL1	6.2	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CA	1	1948	of service	MISO	71
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	GEN1	CCL1	89.9	82.0	98.0	Natural Gas Fired Combined Cycle	NG	CT	3	1987	Operating	MISO	32
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	GT1A	CC1	180.0	160.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	12	2001	Operating	MISO	18
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	GT1B	CC1	180.0	160.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	12	2001	Operating	MISO	18
57160	DuPont Sabine River Works	10789	Sabine River Works	Industrial CHP	TX	ST1A	CC1	145.0	100.0	100.0	Natural Gas Fired Combined Cycle	NG	CA	12	2001	Operating	MISO	18
5530	E F Kenilworth LLC	10805	Kenilworth Energy Facility	IPP CHP	NJ	GEN1	G741	22.0	20.0	22.0	Natural Gas Fired Combined Cycle	NG	CT	3	1989	Operating	PJM	30
5530	E F Kenilworth LLC	10805	Kenilworth Energy Facility	IPP CHP	NJ	GEN2	G741	6.8	4.5	5.5	Natural Gas Fired Combined Cycle	NG	CA	4	1989	Operating	PJM	30
745	Applied Energy Inc	10810	NTC/MCRD Energy Facility	IPP CHP	CA	GEN1	CC10	23.0	21.6	22.0	Natural Gas Fired Combined Cycle	NG	CT	5	1989	Operating	CISO	30
745	Applied Energy Inc	10810	NTC/MCRD Energy Facility	IPP CHP	CA	GEN2	CC10	2.6	2.2	2.4	Natural Gas Fired Combined Cycle	NG	CA	5	1989	Operating	CISO	30
745	Applied Energy Inc	10811	Naval Station Energy Facility	IPP CHP	CA	GEN1	CC11	38.4	36.7	37.5	Natural Gas Fired Combined Cycle	NG	CT	7	1989	Operating	CISO	30
745	Applied Energy Inc	10811	Naval Station Energy Facility	IPP CHP	CA	GEN2	CC11	11.6	9.8	10.0	Natural Gas Fired Combined Cycle	NG	CA	7	1989	Operating	CISO	30
745	Applied Energy Inc	10811	Naval Station Energy Facility	IPP CHP	CA	GEN3	CC11	5.2	4.8	4.8	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	CISO	14
745	Applied Energy Inc	10812	North Island Energy Facility	IPP CHP	CA	GEN1	CC12	36.3	38.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	6	1989	Operating	CISO	30
745	Applied Energy Inc	10812	North Island Energy Facility	IPP CHP	CA	GEN2	CC12	4.0	3.5	3.8	Natural Gas Fired Combined Cycle	NG	CA	6	1989	Operating	CISO	30
82	Ada Cogeneration Ltd Partnership	10819	Ada Cogeneration LP	IPP CHP	MI	GEN1	CC1	23.0	22.0	23.0	Natural Gas Fired Combined Cycle	NG	CT	10	1990	Operating	MISO	29
82	Ada Cogeneration Ltd Partnership	10819	Ada Cogeneration LP	IPP CHP	MI	GEN2	CC1	10.1	8.0	9.0	Natural Gas Fired Combined Cycle	NG	CA	10	1990	Operating	MISO	29
15114	Pittsfield Generating Company, LP	50002	Pittsfield Generating LP	IPP CHP	MA	GEN1	CC1	40.7	35.2	43.3	Natural Gas Fired Combined Cycle	NG	CT	7	1990	Operating	ISNE	29
15114	Pittsfield Generating Company, LP	50002	Pittsfield Generating LP	IPP CHP	MA	GEN2	CC1	40.7	35.2	43.3	Natural Gas Fired Combined Cycle	NG	CT	7	1990	Operating	ISNE	29
15114	Pittsfield Generating Company, LP	50002	Pittsfield Generating LP	IPP CHP	MA	GEN3	CC1	40.7	35.2	43.3	Natural Gas Fired Combined Cycle	NG	CT	7	1990	Operating	ISNE	29
15114	Pittsfield Generating Company, LP	50002	Pittsfield Generating LP	IPP CHP	MA	GEN4	CC1	53.4	45.8	53.4	Natural Gas Fired Combined Cycle	NG	CA	7	1990	Operating	ISNE	29
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG1	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CT	3	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG2	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CT	3	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG3	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG4	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CT	3	1992	Operating	NYIS	27

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG5	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	STG1	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CA	3	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	STG2	CC1	95.2	99.6	100.0	Natural Gas Fired Combined Cycle	NG	CA	3	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	STG3	CC1	95.2	99.5	100.0	Natural Gas Fired Combined Cycle	NG	CA	4	1992	Operating	NYIS	27
3890	EFS Cogen Holdings I LLC	50006	Linden Cogen Plant	IPP CHP	NJ	GTG6	CC1	212.5	158.3	179.9	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	NYIS	17
14254	Oxy Vinyls LP	50043	Battleground	Industrial CHP	TX	GT1	CC1	104.2	66.0	74.0	Natural Gas Fired Combined Cycle	NG	CT	5	1982	Operating	ERCO	37
14254	Oxy Vinyls LP	50043	Battleground	Industrial CHP	TX	GT2	CC1	104.2	66.0	74.0	Natural Gas Fired Combined Cycle	NG	CT	6	1982	Operating	ERCO	37
14254	Oxy Vinyls LP	50043	Battleground	Industrial CHP	TX	ST	CC1	87.4	62.0	74.0	Natural Gas Fired Combined Cycle	NG	CA	8	1982	Operating	ERCO	37
14254	Oxy Vinyls LP	50043	Battleground	Industrial CHP	TX	GT3	CC1	84.9	69.0	78.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	ERCO	14
16625	San Diego State University	50061	San Diego State University	Commercial CHP	CA	GEN2	CC1	5.1	4.6	4.8	Natural Gas Fired Combined Cycle	NG	CT	9	2002	Operating	CISO	17
16625	San Diego State University	50061	San Diego State University	Commercial CHP	CA	GEN3	CC1	5.1	4.6	4.8	Natural Gas Fired Combined Cycle	NG	CT	9	2002	Operating	CISO	17
16625	San Diego State University	50061	San Diego State University	Commercial CHP	CA	GEN4	CC1	4.1	4.1	4.1	Natural Gas Fired Combined Cycle	NG	CA	12	2002	Operating	CISO	17
54700	Paris Generation LP	50109	Paris Energy Center	IPP Non-CHP	TX	GEN1	CC1	87.8	78.0	91.0	Natural Gas Fired Combined Cycle	NG	CT	7	1989	Operating	ERCO	30
54700	Paris Generation LP	50109	Paris Energy Center	IPP Non-CHP	TX	GEN2	CC1	87.8	80.0	94.0	Natural Gas Fired Combined Cycle	NG	CT	7	1989	Operating	ERCO	30
54700	Paris Generation LP	50109	Paris Energy Center	IPP Non-CHP	TX	GEN3	CC1	90.0	78.0	90.0	Natural Gas Fired Combined Cycle	NG	CA	12	1989	Operating	ERCO	30
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN4	HCWP	7.6	7.6	7.6	Natural Gas Fired Combined Cycle	NG	CA	10	1951	Operating	ERCO	68
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN5	HCWP	6.0	6.0	6.0	Natural Gas Fired Combined Cycle	NG	CA	9	1959	Operating	ERCO	60
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN7	HCWP	28.8	27.6	27.2	Natural Gas Fired Combined Cycle	NG	CA	1	1979	Operating	ERCO	40
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN8	HCWP	48.5	46.5	45.8	Natural Gas Fired Combined Cycle	NG	CT	11	1987	Operating	ERCO	32
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN9	HCWP	27.2	26.1	25.7	Natural Gas Fired Combined Cycle	NG	CA	11	2004	Operating	ERCO	15
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Commercial CHP	TX	GEN10	HCWP	34.4	33.0	32.5	Natural Gas Fired Combined Cycle	NG	CT	3	2010	Operating	ERCO	9
54777	Signal Hill Generating LLC	50127	Signal Hill Generating LLC	IPP Non-CHP	TX	GTA	CC1	20.0	19.7	19.7	Natural Gas Fired Combined Cycle	NG	CT	6	1987	Operating	ERCO	32
54777	Signal Hill Generating LLC	50127	Signal Hill Generating LLC	IPP Non-CHP	TX	GTB	CC1	20.0	19.7	19.7	Natural Gas Fired Combined Cycle	NG	CT	6	1987	Operating	ERCO	32
54777	Signal Hill Generating LLC	50127	Signal Hill Generating LLC	IPP Non-CHP	TX	GTC	CC1	20.0	19.7	19.7	Natural Gas Fired Combined Cycle	NG	CT	6	1987	Operating	ERCO	32
54777	Signal Hill Generating LLC	50127	Signal Hill Generating LLC	IPP Non-CHP	TX	STD	CC1	20.0	17.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	6	1987	Operating	ERCO	32
15320	Praxair Inc	50148	Linde Wilmington	Industrial CHP	CA	GEN1	CC1	25.0	21.0	21.0	Natural Gas Fired Combined Cycle	NG	CT	12	1988	Standby/	LDWP	31
15320	Praxair Inc	50148	Linde Wilmington	Industrial CHP	CA	GEN2	CC1	6.0	6.0	6.0	Natural Gas Fired Combined Cycle	NG	CA	12	1988	Standby/	LDWP	31
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GE10	G621	15.0	15.0	15.0	Natural Gas Fired Combined Cycle	NG	CA	1	1964	Operating	ERCO	55
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	IGT	G621	12.0	12.0	12.0	Natural Gas Fired Combined Cycle	NG	CT	1	1969	of service	ERCO	50
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GEN5	G621	15.0	15.0	15.0	Natural Gas Fired Combined Cycle	NG	CA	11	1987	Operating	ERCO	32
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GEN6	G621	35.0	30.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	11	1987	Operating	ERCO	32
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GEN7	G621	6.0	6.0	6.0	Natural Gas Fired Combined Cycle	NG	CA	11	1987	Operating	ERCO	32
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GEN8	G621	35.0	30.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	11	1987	Operating	ERCO	32
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GEN9	G621	15.0	15.0	15.0	Natural Gas Fired Combined Cycle	NG	CA	11	1987	Operating	ERCO	32
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Industrial CHP	TX	GE11	G621	35.0	30.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	11	2000	Operating	ERCO	19
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	CGN1	CC1	125.8	100.0	116.0	Natural Gas Fired Combined Cycle	NG	CT	12	1996	Operating	MISO	23
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	CGN2	CC1	125.8	100.0	116.0	Natural Gas Fired Combined Cycle	NG	CT	1	1997	Operating	MISO	22
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	STG	CC1	22.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	2	1997	Operating	MISO	22
5352	Dow Chemical Co - St Charles	50152	Dow St Charles Operations	Industrial CHP	LA	CSTG	CC1	50.0	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CA	12	2002	Operating	MISO	17
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN94	CC1	82.0	82.0	82.0	Natural Gas Fired Combined Cycle	NG	CT	12	1987	Operating	CISO	32
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN96	CC1	38.5	35.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	12	1987	Operating	CISO	32
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN91	CC1	82.0	82.0	82.0	Natural Gas Fired Combined Cycle	NG	CT	3	1988	Operating	CISO	31
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN92	CC1	82.0	82.0	82.0	Natural Gas Fired Combined Cycle	NG	CT	2	1988	Operating	CISO	31
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN93	CC1	82.0	82.0	82.0	Natural Gas Fired Combined Cycle	NG	CT	1	1988	Operating	CISO	31
867	ARCO Products Co-Watson	50216	Watson Cogeneration	Industrial CHP	CA	GN95	CC1	38.5	35.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	2	1988	Operating	CISO	31
6529	Exxon Mobil Production Co	50270	ExxonMobil Santa Ynez Facility	Industrial CHP	CA	GTG1	CC1	39.5	40.2	39.2	Natural Gas Fired Combined Cycle	NG	CT	9	1993	of service	CISO	26
6529	Exxon Mobil Production Co	50270	ExxonMobil Santa Ynez Facility	Industrial CHP	CA	STG1	CC1	9.8	8.9	8.8	Natural Gas Fired Combined Cycle	NG	CA	10	1993	of service	CISO	26
24457	Calpine Eastern Corp	50292	Bethpage Power Plant	IPP Non-CHP	NY	GEN1	G602	33.7	22.2	23.8	Natural Gas Fired Combined Cycle	NG	CT	8	1989	Operating	NYIS	30
24457	Calpine Eastern Corp	50292	Bethpage Power Plant	IPP Non-CHP	NY	GEN2	G602	33.7	22.2	23.8	Natural Gas Fired Combined Cycle	NG	CT	8	1989	Operating	NYIS	30
24457	Calpine Eastern Corp	50292	Bethpage Power Plant	IPP Non-CHP	NY	GEN3	G602	16.2	10.6	11.4	Natural Gas Fired Combined Cycle	NG	CA	8	1989	Operating	NYIS	30

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
24457	Calpine Eastern Corp	50292	Bethpage Power Plant	IPP Non-CHP	NY	GEN6	G603	60.0	49.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	NYIS	14
24457	Calpine Eastern Corp	50292	Bethpage Power Plant	IPP Non-CHP	NY	GEN7	G603	36.0	33.0	34.0	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	NYIS	14
14293	Nalco Co	50326	Nalco	Commercial CHP	IL	AT1	CC1	4.0	3.0	3.5	Natural Gas Fired Combined Cycle	NG	CT	11	1985	Operating	PJM	34
14293	Nalco Co	50326	Nalco	Commercial CHP	IL	DPOX	CC1	0.7	0.7	0.7	Natural Gas Fired Combined Cycle	NG	CA	11	1985	Operating	PJM	34
21508	Cornell University	50368	Cornell University Central Heat	Commercial CHP	NY	TG1	CT1	1.8	1.0	1.8	Natural Gas Fired Combined Cycle	NG	CA	7	1988	Operating	NYIS	31
21508	Cornell University	50368	Cornell University Central Heat	Commercial CHP	NY	TG2	CT2	5.7	5.3	5.7	Natural Gas Fired Combined Cycle	NG	CA	10	1988	Operating	NYIS	31
21508	Cornell University	50368	Cornell University Central Heat	Commercial CHP	NY	CT1	CT1	15.0	12.3	14.5	Natural Gas Fired Combined Cycle	NG	CT	12	2009	Operating	NYIS	10
21508	Cornell University	50368	Cornell University Central Heat	Commercial CHP	NY	CT2	CT2	15.0	12.3	14.5	Natural Gas Fired Combined Cycle	NG	CT	12	2009	Operating	NYIS	10
55846	Newark Bay Cogeneration Partnership LP	50385	LP	IPP Non-CHP	NJ	GEN1	CC1	42.0	120.2	136.2	Natural Gas Fired Combined Cycle	NG	CT	5	1993	Operating	PJM	26
55846	Newark Bay Cogeneration Partnership LP	50385	LP	IPP Non-CHP	NJ	GEN2	CC1	42.0			Natural Gas Fired Combined Cycle	NG	CT	4	1993	Operating	PJM	26
55846	Newark Bay Cogeneration Partnership LP	50385	LP	IPP Non-CHP	NJ	GEN3	CC1	55.0			Natural Gas Fired Combined Cycle	NG	CA	6	1993	Operating	PJM	26
19588	University of Michigan	50431	University of Michigan	Commercial CHP	MI	TG7	CC1	12.5	11.5	11.5	Natural Gas Fired Combined Cycle	NG	CA	1	1975	Operating	MISO	44
19588	University of Michigan	50431	University of Michigan	Commercial CHP	MI	TG8	CC1	12.5	11.5	11.5	Natural Gas Fired Combined Cycle	NG	CA	1	1975	Operating	MISO	44
19588	University of Michigan	50431	University of Michigan	Commercial CHP	MI	TG1	CC1	12.5	11.5	11.5	Natural Gas Fired Combined Cycle	NG	CA	1	1986	Operating	MISO	33
19588	University of Michigan	50431	University of Michigan	Commercial CHP	MI	TG9	CC1	3.5	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CT	8	1990	Operating	MISO	29
19588	University of Michigan	50431	University of Michigan	Commercial CHP	MI	TG10	CC1	3.5	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CT	6	1992	Operating	MISO	27
9245	Indeck-Energy Serv Silver Spg	50449	Indeck Silver Springs Energy Center	IPP CHP	NY	GEN1	G722	39.4	49.5	63.9	Natural Gas Fired Combined Cycle	NG	CT	5	1991	Operating	NYIS	28
9245	Indeck-Energy Serv Silver Spg	50449	Indeck Silver Springs Energy Center	IPP CHP	NY	GEN2	G722	17.2			Natural Gas Fired Combined Cycle	NG	CA	5	1991	Operating	NYIS	28
9244	Indeck-Oswego Ltd Partnership	50450	Indeck Oswego Energy Center	IPP CHP	NY	GEN1	CC1	41.2	48.9	61.4	Natural Gas Fired Combined Cycle	NG	CT	6	1990	Operating	NYIS	29
9244	Indeck-Oswego Ltd Partnership	50450	Indeck Oswego Energy Center	IPP CHP	NY	GEN2	CC1	16.2			Natural Gas Fired Combined Cycle	NG	CA	6	1990	Operating	NYIS	29
9243	Indeck-Yerkes Ltd Partnership	50451	Indeck Yerkes Energy Center	IPP CHP	NY	GEN1	CC1	40.6	47.7	56.7	Natural Gas Fired Combined Cycle	NG	CT	12	1989	Operating	NYIS	30
9243	Indeck-Yerkes Ltd Partnership	50451	Indeck Yerkes Energy Center	IPP CHP	NY	GEN2	CC1	19.3			Natural Gas Fired Combined Cycle	NG	CA	12	1989	Operating	NYIS	30
9263	Indeck-Corinth Ltd Partnership	50458	Indeck Corinth Energy Center	IPP CHP	NY	GEN1	G723	92.0	74.4	92.2	Natural Gas Fired Combined Cycle	NG	CT	2	1995	Operating	NYIS	24
9263	Indeck-Corinth Ltd Partnership	50458	Indeck Corinth Energy Center	IPP CHP	NY	GEN2	G723	55.0	56.0	46.5	Natural Gas Fired Combined Cycle	NG	CA	3	1995	Operating	NYIS	24
2956	Capitol District Energy Center	50498	Capitol District Energy Center	IPP CHP	CT	GTG	CC1	39.8	55.2	61.3	Natural Gas Fired Combined Cycle	NG	CT	10	1988	Operating	ISNE	31
2956	Capitol District Energy Center	50498	Capitol District Energy Center	IPP CHP	CT	STG	CC1	30.7	0.0		Natural Gas Fired Combined Cycle	NG	CA	10	1988	Operating	ISNE	31
8303	Harbor Cogeneration Co.	50541	Harbor Cogen	IPP Non-CHP	CA	GEN1	HCCC	82.3	80.8	84.5	Natural Gas Fired Combined Cycle	NG	CT	12	1988	Operating	CISO	31
8303	Harbor Cogeneration Co.	50541	Harbor Cogen	IPP Non-CHP	CA	ST1	HCCC	13.6	9.9	10.4	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	CISO	18
8303	Harbor Cogeneration Co.	50541	Harbor Cogen	IPP Non-CHP	CA	ST2	HCCC	11.5	11.0	11.0	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	CISO	18
19876	Virginia Electric & Power Co	50555	Rosemary Power Station	Electric Utility	NC	GEN1	G785	86.0	75.0	88.0	Natural Gas Fired Combined Cycle	NG	CT	11	1990	Operating	PJM	29
19876	Virginia Electric & Power Co	50555	Rosemary Power Station	Electric Utility	NC	GEN2	G785	40.0	36.0	44.0	Natural Gas Fired Combined Cycle	NG	CT	11	1990	Operating	PJM	29
19876	Virginia Electric & Power Co	50555	Rosemary Power Station	Electric Utility	NC	GEN3	G785	54.0	54.0	54.0	Natural Gas Fired Combined Cycle	NG	CA	11	1990	Operating	PJM	29
17355	Oklahoma Cogeneration LLC	50558	Oklahoma Cogeneration Project	IPP CHP	OK	GT01	CC01	72.5	67.3	67.3	Natural Gas Fired Combined Cycle	NG	CT	9	1989	Operating	SWPP	30
17355	Oklahoma Cogeneration LLC	50558	Oklahoma Cogeneration Project	IPP CHP	OK	ST01	CC01	49.9	44.1	44.1	Natural Gas Fired Combined Cycle	NG	CA	9	1989	Operating	SWPP	30
49942	Eagle Point Power Generation LLC	50561	Eagle Point Power Generation	IPP Non-CHP	NJ	GTG1	CC1	90.0	85.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	11	1990	Operating	PJM	29
49942	Eagle Point Power Generation LLC	50561	Eagle Point Power Generation	IPP Non-CHP	NJ	GTG2	CC1	90.0	85.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	11	1990	Operating	PJM	29
49942	Eagle Point Power Generation LLC	50561	Eagle Point Power Generation	IPP Non-CHP	NJ	STG1	CC1	45.0	40.0	45.0	Natural Gas Fired Combined Cycle	NG	CA	4	1991	Operating	PJM	28
49942	Eagle Point Power Generation LLC	50561	Eagle Point Power Generation	IPP Non-CHP	NJ	STG2	CC1	26.8	26.8	26.8	Natural Gas Fired Combined Cycle	NG	CA	5	2016	Operating	PJM	3
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	LMA	J272	58.5	31.8	34.8	Natural Gas Fired Combined Cycle	NG	CT	6	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	LMB	J272	58.5	31.8	34.8	Natural Gas Fired Combined Cycle	NG	CT	6	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	LMC	J272	58.5	31.8	34.8	Natural Gas Fired Combined Cycle	NG	CT	7	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	LMD	J272	58.5	31.8	34.8	Natural Gas Fired Combined Cycle	NG	CT	7	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	LME	J272	58.5	31.8	34.8	Natural Gas Fired Combined Cycle	NG	CT	7	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	STA	J272	52.2	52.0	52.0	Natural Gas Fired Combined Cycle	NG	CA	6	1994	Operating	PSCO	25
30151	Tri-State G & T Assn, Inc	50707	JM Shafer Generating Station	Electric Utility	CO	STB	J272	52.2	52.0	52.0	Natural Gas Fired Combined Cycle	NG	CA	6	1994	Operating	PSCO	25
14182	Sterling Power Partners LP	50744	Sterling Power Plant	IPP Non-CHP	NY	GEN1	CC1	47.7	38.8	47.6	Natural Gas Fired Combined Cycle	NG	CT	6	1991	Operating	NYIS	28
14182	Sterling Power Partners LP	50744	Sterling Power Plant	IPP Non-CHP	NY	GEN2	CC1	16.5	16.0	16.5	Natural Gas Fired Combined Cycle	NG	CA	7	1991	Operating	NYIS	28
2871	OLS Energy-Agnews Inc.	50748	Agnews Power Plant	IPP Non-CHP	CA	GEN1	CC1	24.4	24.4	24.4	Natural Gas Fired Combined Cycle	NG	CT	11	1990	Operating	CISO	29
2871	OLS Energy-Agnews Inc.	50748	Agnews Power Plant	IPP Non-CHP	CA	GEN2	CC1	7.6	7.3	7.4	Natural Gas Fired Combined Cycle	NG	CA	11	1990	Operating	CISO	29
61536	Consolidated Edison Energy, Inc.	50799	Parlin Power Plant	IPP Non-CHP	NJ	GEN1	PEC	45.9	35.9	42.2	Natural Gas Fired Combined Cycle	NG	CT	6	1991	Operating	PJM	28

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
61536	Consolidated Edison Energy, Inc.	50799	Parlin Power Plant	IPP Non-CHP	NJ	GEN2	PEC	45.9	37.5	43.7	Natural Gas Fired Combined Cycle	NG	CT	6	1991	Operating	PJM	28
61536	Consolidated Edison Energy, Inc.	50799	Parlin Power Plant	IPP Non-CHP	NJ	GEN3	PEC	21.6	20.6	20.6	Natural Gas Fired Combined Cycle	NG	CA	6	1991	Operating	PJM	28
61536	Consolidated Edison Energy, Inc.	50799	Parlin Power Plant	IPP Non-CHP	NJ	GEN4	PEC	21.6	20.6	20.6	Natural Gas Fired Combined Cycle	NG	CA	6	1991	Operating	PJM	28
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN1	CC1	84.9	69.8	79.0	Natural Gas Fired Combined Cycle	NG	CT	11	1985	Operating	ERCO	34
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN2	CC1	84.9	69.8	80.6	Natural Gas Fired Combined Cycle	NG	CT	12	1985	Operating	ERCO	34
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN3	CC1	84.9	70.1	78.2	Natural Gas Fired Combined Cycle	NG	CT	12	1985	Operating	ERCO	34
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN4	CC1	84.9	75.0	79.0	Natural Gas Fired Combined Cycle	NG	CT	3	1986	Operating	ERCO	33
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN5	CC1	84.9	68.4	76.3	Natural Gas Fired Combined Cycle	NG	CT	4	1986	Operating	ERCO	33
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN6	CC1	129.2	120.1	126.6	Natural Gas Fired Combined Cycle	NG	CA	4	1986	Operating	ERCO	33
55879	Optim Energy LLC	50815	Optim Energy Altura Cogen LLC	IPP CHP	TX	GEN7	CC1	89.9	69.0	74.3	Natural Gas Fired Combined Cycle	NG	CT	6	1995	Operating	ERCO	24
61261	Berkeley Cogeneration Facility	50849	PE Berkeley	Commercial CHP	CA	GEN1	CC1	23.0	21.0	23.0	Natural Gas Fired Combined Cycle	NG	CT	6	1987	Operating	CISO	32
61261	Berkeley Cogeneration Facility	50849	PE Berkeley	Commercial CHP	CA	GEN2	CC1	5.5	2.0	4.0	Natural Gas Fired Combined Cycle	NG	CA	6	1987	Operating	CISO	32
14265	OLS Energy-Chino	50850	OLS Energy Chino	IPP CHP	CA	GEN1	CC1	23.5	22.5	22.5	Natural Gas Fired Combined Cycle	NG	CT	12	1987	Operating	CISO	32
14265	OLS Energy-Chino	50850	OLS Energy Chino	IPP CHP	CA	GEN2	CC1	7.3	6.5	6.0	Natural Gas Fired Combined Cycle	NG	CA	12	1987	Operating	CISO	32
56835	CSUCI Site Authority	50851	CSUCI Site Authority	IPP CHP	CA	GEN1	CC1	23.5	21.5	22.1	Natural Gas Fired Combined Cycle	NG	CT	3	1988	Operating	CISO	31
56835	CSUCI Site Authority	50851	CSUCI Site Authority	IPP CHP	CA	GEN2	CC1	7.6	6.8	6.9	Natural Gas Fired Combined Cycle	NG	CA	3	1988	Operating	CISO	31
56516	Morris Energy Operations Company, LLC	50852	Elmwood Energy Holdings LLC	IPP Non-CHP	NJ	GEN1	CC1	59.0	70.0	70.0	Natural Gas Fired Combined Cycle	NG	CT	4	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	50852	Elmwood Energy Holdings LLC	IPP Non-CHP	NJ	GEN2	CC1	24.0			Natural Gas Fired Combined Cycle	NG	CA	5	1989	Operating	PJM	30
20541	Wheelabrator Environmental Systems	50876	Wheelabrator Norwalk Energy	IPP CHP	CA	GEN1	CC1	23.0	23.6	23.6	Natural Gas Fired Combined Cycle	NG	CT	2	1988	Operating	CISO	31
20541	Wheelabrator Environmental Systems	50876	Wheelabrator Norwalk Energy	IPP CHP	CA	GEN2	CC1	7.7	3.7	3.7	Natural Gas Fired Combined Cycle	NG	CA	2	1988	Operating	CISO	31
49893	Invenergy Services LLC	50949	Hardee Power Station	IPP Non-CHP	FL	GEN1	CC01	95.9	70.0	85.0	Natural Gas Fired Combined Cycle	NG	CT	1	1993	Operating	TEC	26
49893	Invenergy Services LLC	50949	Hardee Power Station	IPP Non-CHP	FL	GEN2	CC01	95.9	70.0	85.0	Natural Gas Fired Combined Cycle	NG	CT	1	1993	Operating	TEC	26
49893	Invenergy Services LLC	50949	Hardee Power Station	IPP Non-CHP	FL	GEN3	CC01	95.9	78.0	85.0	Natural Gas Fired Combined Cycle	NG	CA	1	1993	Operating	TEC	26
19876	Virginia Electric & Power Co	50966	Bellmeade Power Station	Electric Utility	VA	1	G781	110.0	95.0	95.0	Natural Gas Fired Combined Cycle	NG	CT	2	1997	Operating	PJM	22
19876	Virginia Electric & Power Co	50966	Bellmeade Power Station	Electric Utility	VA	2	G781	110.0	95.0	95.0	Natural Gas Fired Combined Cycle	NG	CT	2	1997	Operating	PJM	22
19876	Virginia Electric & Power Co	50966	Bellmeade Power Station	Electric Utility	VA	3	G781	110.0	77.0	77.0	Natural Gas Fired Combined Cycle	NG	CA	2	1997	Operating	PJM	22
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN32	BLK1	15.6	10.5	10.7	Natural Gas Fired Combined Cycle	NG	CA	6	1957	Operating	MISO	62
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN31	BLK1	10.0	8.4	8.6	Natural Gas Fired Combined Cycle	NG	CA	6	1962	Operating	MISO	57
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN33	BLK1	25.5	21.5	22.0	Natural Gas Fired Combined Cycle	NG	CA	6	1978	Operating	MISO	41
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN35	BLK1	40.5	39.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	12	1983	of service	MISO	36
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN41	BLK1	41.6	36.1	46.4	Natural Gas Fired Combined Cycle	NG	CT	12	2011	Operating	MISO	8
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN42	BLK1	41.6	36.1	46.4	Natural Gas Fired Combined Cycle	NG	CT	11	2011	Operating	MISO	8
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN43	BLK1	41.6	36.1	46.4	Natural Gas Fired Combined Cycle	NG	CT	11	2011	Operating	MISO	8
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Industrial CHP	TX	GN44	BLK1	41.6	36.1	46.4	Natural Gas Fired Combined Cycle	NG	CT	10	2011	Operating	MISO	8
24202	Carr Street Generating Sta LP	50978	Carr Street Generating Station	IPP Non-CHP	NY	GEN1	CC1	48.8	33.0	40.8	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	NYIS	26
24202	Carr Street Generating Sta LP	50978	Carr Street Generating Station	IPP Non-CHP	NY	GEN2	CC1	48.8	33.0	40.8	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	NYIS	26
24202	Carr Street Generating Sta LP	50978	Carr Street Generating Station	IPP Non-CHP	NY	GEN3	CC1	25.0	22.2	24.6	Natural Gas Fired Combined Cycle	NG	CA	7	1993	Operating	NYIS	26
27769	Ocean State Power Co	51030	Ocean State Power	IPP Non-CHP	RI	GEN1	OSP1	82.8	71.2	77.8	Natural Gas Fired Combined Cycle	NG	CT	12	1990	Operating	ISNE	29
27769	Ocean State Power Co	51030	Ocean State Power	IPP Non-CHP	RI	GEN2	OSP1	82.8	71.2	77.8	Natural Gas Fired Combined Cycle	NG	CT	12	1990	Operating	ISNE	29
27769	Ocean State Power Co	51030	Ocean State Power	IPP Non-CHP	RI	GEN3	OSP1	88.6	76.2	83.3	Natural Gas Fired Combined Cycle	NG	CA	12	1990	Operating	ISNE	29
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN1	CC1	57.0	57.0	57.0	Natural Gas Fired Combined Cycle	NG	CA	6	1958	Operating	MISO	61
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN2	CC1	88.0	80.0	80.0	Natural Gas Fired Combined Cycle	NG	CA	6	1962	Operating	MISO	57
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN3	CC1	90.0	94.0	94.0	Natural Gas Fired Combined Cycle	NG	CA	6	1966	Operating	MISO	53
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN4	CC1	76.5	49.0	49.0	Natural Gas Fired Combined Cycle	NG	CA	6	1969	Operating	MISO	50
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN5	CC1	76.5	52.0	65.0	Natural Gas Fired Combined Cycle	NG	CT	11	1978	Operating	MISO	41
5347	Dow Chemical Co	52006	LaO Energy Systems	Industrial CHP	LA	GEN6	CC1	76.5	52.0	65.0	Natural Gas Fired Combined Cycle	NG	CT	2	1979	Operating	MISO	40
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN1	UNT5	122.0	104.7	122.0	Natural Gas Fired Combined Cycle	NG	CT	11	1991	Operating	PJM	28
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN2	UNT5	122.0	104.7	122.0	Natural Gas Fired Combined Cycle	NG	CT	12	1991	Operating	PJM	28
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN3	UNT5	132.0	123.0	132.0	Natural Gas Fired Combined Cycle	NG	CA	12	1991	Operating	PJM	28
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN4	UNT6	122.0	104.7	122.0	Natural Gas Fired Combined Cycle	NG	CT	1	1992	Operating	PJM	27

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN5	UNT6	122.0	104.7	122.0	Natural Gas Fired Combined Cycle	NG	CT	1	1992	Operating	PJM	27
5310	Doswell Ltd Partnership	52019	Doswell Energy Center	IPP Non-CHP	VA	GEN6	UNT6	132.0	123.0	132.0	Natural Gas Fired Combined Cycle	NG	CA	1	1992	Operating	PJM	27
56516	Morris Energy Operations Company, LLC	52026	Dartmouth Power Associates LP	IPP Non-CHP	MA	GEN1	CC1	45.0	62.1	67.7	Natural Gas Fired Combined Cycle	NG	CT	3	1992	Operating	ISNE	27
56516	Morris Energy Operations Company, LLC	52026	Dartmouth Power Associates LP	IPP Non-CHP	MA	GEN2	CC1	32.0			Natural Gas Fired Combined Cycle	NG	CA	3	1992	Operating	ISNE	27
19153	Nassau Energy Corp	52056	Nassau Energy Corp	IPP CHP	NY	GT1	CC1	43.0	43.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	3	1991	Operating	NYIS	28
19153	Nassau Energy Corp	52056	Nassau Energy Corp	IPP CHP	NY	ST1	CC1	12.0	12.0	12.0	Natural Gas Fired Combined Cycle	NG	CA	3	1991	Operating	NYIS	28
8153	Hartford Steam Co	52061	Hartford Hospital Cogeneration	Commercial CHP	CT	GEN2	CC1	4.2	2.4	2.4	Natural Gas Fired Combined Cycle	NG	CA	7	1988	Operating	ISNE	31
8153	Hartford Steam Co	52061	Hartford Hospital Cogeneration	Commercial CHP	CT	GEN3	CC1	6.2	5.2	6.2	Natural Gas Fired Combined Cycle	NG	CT	7	1988	Operating	ISNE	31
19524	University of California-LA	52073	UCLA So Campus Cogen Project	Commercial CHP	CA	GEN1	CC1	14.5	12.5	13.5	Natural Gas Fired Combined Cycle	NG	CT	10	1993	Operating	LDWP	26
19524	University of California-LA	52073	UCLA So Campus Cogen Project	Commercial CHP	CA	GEN2	CC1	14.5	12.5	13.5	Natural Gas Fired Combined Cycle	NG	CT	10	1993	Operating	LDWP	26
19524	University of California-LA	52073	UCLA So Campus Cogen Project	Commercial CHP	CA	GEN3	CC1	14.0	11.0	12.0	Natural Gas Fired Combined Cycle	NG	CA	10	1993	Operating	LDWP	26
22652	Texas City Cogeneration LLC	52088	Texas City Power Plant	IPP CHP	TX	GEN1	CC1	141.0	139.0	139.0	Natural Gas Fired Combined Cycle	NG	CA	5	1987	Operating	ERCO	32
22652	Texas City Cogeneration LLC	52088	Texas City Power Plant	IPP CHP	TX	GEN2	CC1	103.0	104.0	115.0	Natural Gas Fired Combined Cycle	NG	CT	5	1987	Operating	ERCO	32
22652	Texas City Cogeneration LLC	52088	Texas City Power Plant	IPP CHP	TX	GEN3	CC1	103.0	104.0	115.0	Natural Gas Fired Combined Cycle	NG	CT	5	1987	Operating	ERCO	32
22652	Texas City Cogeneration LLC	52088	Texas City Power Plant	IPP CHP	TX	GEN4	CC1	103.0	104.0	115.0	Natural Gas Fired Combined Cycle	NG	CT	5	1987	Operating	ERCO	32
49732	Chevron Products Company-Richmond	52109	Richmond Cogen	Industrial CHP	CA	GEN1	CC1	62.6	50.0	52.0	Natural Gas Fired Combined Cycle	NG	CT	8	1992	Operating	CISO	27
49732	Chevron Products Company-Richmond	52109	Richmond Cogen	Industrial CHP	CA	GEN2	CC1	62.6	50.0	52.0	Natural Gas Fired Combined Cycle	NG	CT	9	1992	Operating	CISO	27
49732	Chevron Products Company-Richmond	52109	Richmond Cogen	Industrial CHP	CA	GEN5	CC1	30.4	30.4	30.4	Natural Gas Fired Combined Cycle	NG	CA	3	2006	Operating	CISO	13
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-61	PLTB	94.5	68.3	76.1	Natural Gas Fired Combined Cycle	NG	CT	10	1982	Operating	ERCO	37
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-63	PLTB	94.5	68.3	80.0	Natural Gas Fired Combined Cycle	NG	CT	8	1982	Operating	ERCO	37
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-64	PLTB	64.8	35.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	9	1982	Operating	ERCO	37
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-66	PLTB	119.0	95.6	106.5	Natural Gas Fired Combined Cycle	NG	CT	12	1983	Operating	ERCO	36
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-65	PLTB	111.3	95.2	95.2	Natural Gas Fired Combined Cycle	NG	CA	2	1984	Operating	ERCO	35
59875	Olin Blue Cube Operations	52120	Freeport Energy	Industrial CHP	TX	G-67	PLTB	119.0	95.6	106.5	Natural Gas Fired Combined Cycle	NG	CT	3	1984	Operating	ERCO	35
17566	South Houston Green Power LLC	52132	Power Station 4	Industrial CHP	TX	GEN1	CC1	78.2	69.0	78.0	Natural Gas Fired Combined Cycle	NG	CT	9	1986	Operating	ERCO	33
17566	South Houston Green Power LLC	52132	Power Station 4	Industrial CHP	TX	GEN2	CC1	78.2	69.0	78.0	Natural Gas Fired Combined Cycle	NG	CT	9	1986	Operating	ERCO	33
17566	South Houston Green Power LLC	52132	Power Station 4	Industrial CHP	TX	GEN3	CC1	34.7	34.0	34.0	Natural Gas Fired Combined Cycle	NG	CA	9	1986	of service	ERCO	33
15300	Power Resources Ltd	52176	C R Wing Cogen Plant	IPP CHP	TX	GEN1	CC1	77.5	71.0	71.0	Natural Gas Fired Combined Cycle	NG	CT	7	1987	Operating	ERCO	32
15300	Power Resources Ltd	52176	C R Wing Cogen Plant	IPP CHP	TX	GEN2	CC1	77.5	71.0	71.0	Natural Gas Fired Combined Cycle	NG	CT	7	1987	Operating	ERCO	32
15300	Power Resources Ltd	52176	C R Wing Cogen Plant	IPP CHP	TX	GEN3	CC1	75.0	70.0	70.0	Natural Gas Fired Combined Cycle	NG	CA	4	1988	Operating	ERCO	31
6838	Rensselaer Generating LLC	54034	Rensselaer Cogen	IPP Non-CHP	NY	GEN1	G701	49.2	47.0	55.8	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	NYIS	25
6838	Rensselaer Generating LLC	54034	Rensselaer Cogen	IPP Non-CHP	NY	GEN2	G701	39.0	33.4	30.0	Natural Gas Fired Combined Cycle	NG	CA	4	1994	Operating	NYIS	25
11127	Lockport Energy Associates LP	54041	Lockport Energy Associates LP	IPP CHP	NY	GEN1	LEA1	48.7	42.3	51.3	Natural Gas Fired Combined Cycle	NG	CT	7	1992	Operating	NYIS	27
11127	Lockport Energy Associates LP	54041	Lockport Energy Associates LP	IPP CHP	NY	GEN2	LEA1	48.7	42.3	51.3	Natural Gas Fired Combined Cycle	NG	CT	7	1992	Operating	NYIS	27
11127	Lockport Energy Associates LP	54041	Lockport Energy Associates LP	IPP CHP	NY	GEN3	LEA1	48.7	42.3	51.3	Natural Gas Fired Combined Cycle	NG	CT	7	1992	Operating	NYIS	27
11127	Lockport Energy Associates LP	54041	Lockport Energy Associates LP	IPP CHP	NY	GEN4	LEA1	75.2	75.2	75.2	Natural Gas Fired Combined Cycle	NG	CA	9	1992	Operating	NYIS	27
14584	Pawtucket Power Associates LP	54056	Pawtucket Power Associates	IPP Non-CHP	RI	GEN1	CC1	41.8	33.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	12	1990	Operating	ISNE	29
14584	Pawtucket Power Associates LP	54056	Pawtucket Power Associates	IPP Non-CHP	RI	GEN2	CC1	27.0	27.0	27.0	Natural Gas Fired Combined Cycle	NG	CA	12	1990	Operating	ISNE	29
9261	Indeck-Olean Ltd Partnership	54076	Indeck Olean Energy Center	IPP CHP	NY	GEN1	G721	46.0	34.1	43.2	Natural Gas Fired Combined Cycle	NG	CT	1	1994	Operating	NYIS	25
9261	Indeck-Olean Ltd Partnership	54076	Indeck Olean Energy Center	IPP CHP	NY	GEN2	G721	44.6	44.6	44.6	Natural Gas Fired Combined Cycle	NG	CA	1	1994	Operating	NYIS	25
9393	International Paper Co-Riverdl	54096	International Paper Riverdale Mill	Industrial CHP	AL	GEN3	CC01	17.0	17.0	17.0	Natural Gas Fired Combined Cycle	NG	CA	11	1994	Operating	SOCO	25
9393	International Paper Co-Riverdl	54096	International Paper Riverdale Mill	Industrial CHP	AL	GEN4	CC01	38.2	38.2	38.2	Natural Gas Fired Combined Cycle	NG	CT	11	1994	Standby/	SOCO	25
10349	KIAC Partners	54114	Kennedy International Airport Cogen	IPP CHP	NY	GEN1	CC1	47.1	49.9	51.0	Natural Gas Fired Combined Cycle	NG	CT	12	1994	Operating	NYIS	25
10349	KIAC Partners	54114	Kennedy International Airport Cogen	IPP CHP	NY	GEN2	CC1	47.1	49.7	47.3	Natural Gas Fired Combined Cycle	NG	CT	12	1994	Operating	NYIS	25
10349	KIAC Partners	54114	Kennedy International Airport Cogen	IPP CHP	NY	GEN3	CC1	27.0	25.9	25.9	Natural Gas Fired Combined Cycle	NG	CA	1	1995	Operating	NYIS	24
50136	North American Energy Services	54131	Fortistar North Tonawanda	IPP CHP	NY	GEN1	CC1	38.3	39.1	48.5	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	NYIS	26
50136	North American Energy Services	54131	Fortistar North Tonawanda	IPP CHP	NY	GEN2	CC1	17.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	7	1993	Operating	NYIS	26
16553	Saguaro Power Co	54271	Saguaro Power	IPP CHP	NV	CTG1	CC1	45.1	36.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	9	1991	Operating	NEVP	28
16553	Saguaro Power Co	54271	Saguaro Power	IPP CHP	NV	CTG2	CC1	45.1	36.0	38.0	Natural Gas Fired Combined Cycle	NG	CT	9	1991	Operating	NEVP	28
16553	Saguaro Power Co	54271	Saguaro Power	IPP CHP	NV	STG	CC1	37.0	29.0	29.0	Natural Gas Fired Combined Cycle	NG	CA	9	1991	Operating	NEVP	28

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
27770	Ocean State Power II	54324	Ocean State Power II	IPP Non-CHP	RI	GEN1	OSP2	82.8	71.2	77.8	Natural Gas Fired Combined Cycle	NG	CT	10	1991	Operating	ISNE	28
27770	Ocean State Power II	54324	Ocean State Power II	IPP Non-CHP	RI	GEN2	OSP2	82.8	71.2	77.8	Natural Gas Fired Combined Cycle	NG	CT	10	1991	Operating	ISNE	28
27770	Ocean State Power II	54324	Ocean State Power II	IPP Non-CHP	RI	GEN3	OSP2	88.6	76.2	83.3	Natural Gas Fired Combined Cycle	NG	CA	10	1991	Operating	ISNE	28
2468	Bucknell University	54333	Bucknell University	Commercial CHP	PA	G502	CC1	1.2	0.5	1.2	Natural Gas Fired Combined Cycle	NG	CA	10	1991	of service	PJM	28
2468	Bucknell University	54333	Bucknell University	Commercial CHP	PA	G001	CC1	4.7	4.3	5.5	Natural Gas Fired Combined Cycle	NG	CT	6	1998	Operating	PJM	21
13365	Nevada Cogeneration Assoc # 2	54349	Mountain	IPP CHP	NV	GTA	STG1	22.2	21.7	21.7	Natural Gas Fired Combined Cycle	NG	CT	11	1992	Operating	NEVP	27
13365	Nevada Cogeneration Assoc # 2	54349	Mountain	IPP CHP	NV	GTB	STG1	22.2	21.7	21.7	Natural Gas Fired Combined Cycle	NG	CT	12	1992	Operating	NEVP	27
13365	Nevada Cogeneration Assoc # 2	54349	Mountain	IPP CHP	NV	GTC	STG1	22.2	21.7	21.7	Natural Gas Fired Combined Cycle	NG	CT	12	1992	Operating	NEVP	27
13365	Nevada Cogeneration Assoc # 2	54349	Mountain	IPP CHP	NV	STM	STG1	29.7	28.0	28.0	Natural Gas Fired Combined Cycle	NG	CA	12	1992	Operating	NEVP	27
13399	Nevada Cogeneration Assoc # 1	54350	Nevada Cogen Assoc#1 GarnetVly	IPP CHP	NV	GTA	CC1	21.7	20.5	22.0	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NEVP	27
13399	Nevada Cogeneration Assoc # 1	54350	Nevada Cogen Assoc#1 GarnetVly	IPP CHP	NV	GTB	CC1	21.7	20.5	22.0	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NEVP	27
13399	Nevada Cogeneration Assoc # 1	54350	Nevada Cogen Assoc#1 GarnetVly	IPP CHP	NV	GTC	CC1	21.7	20.5	22.0	Natural Gas Fired Combined Cycle	NG	CT	4	1992	Operating	NEVP	27
13399	Nevada Cogeneration Assoc # 1	54350	Nevada Cogen Assoc#1 GarnetVly	IPP CHP	NV	STM	CC1	29.7	24.0	19.0	Natural Gas Fired Combined Cycle	NG	CA	5	1992	Operating	NEVP	27
49901	Northern Star Generation Services Co LLC	54365	Orange Cogeneration Facility	IPP CHP	FL	APC1	CC1	54.0	43.0	43.0	Natural Gas Fired Combined Cycle	NG	CT	3	1995	Operating	FPC	24
49901	Northern Star Generation Services Co LLC	54365	Orange Cogeneration Facility	IPP CHP	FL	APC2	CC1	54.0	43.0	43.0	Natural Gas Fired Combined Cycle	NG	CT	2	1995	Operating	FPC	24
49901	Northern Star Generation Services Co LLC	54365	Orange Cogeneration Facility	IPP CHP	FL	APC3	CC1	28.6	24.6	24.6	Natural Gas Fired Combined Cycle	NG	CA	3	1995	Operating	FPC	24
22208	University of Colorado	54372	University of Colorado	Commercial CHP	CO	GT1	CC1	16.0	15.0	16.0	Natural Gas Fired Combined Cycle	NG	CT	8	1992	Operating	PSCO	27
22208	University of Colorado	54372	University of Colorado	Commercial CHP	CO	GT2	CC1	16.0	15.0	16.0	Natural Gas Fired Combined Cycle	NG	CT	8	1992	Operating	PSCO	27
22208	University of Colorado	54372	University of Colorado	Commercial CHP	CO	ST1	CC1	1.0	1.0	1.0	Natural Gas Fired Combined Cycle	NG	CA	8	1992	Operating	PSCO	27
58945	EthosEnergy Power Plant Services	54424	Quantum Pasco Power LP	IPP CHP	FL	GT1	CC1	57.4	48.5	48.5	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	TEC	26
58945	EthosEnergy Power Plant Services	54424	Quantum Pasco Power LP	IPP CHP	FL	GT2	CC1	57.4	48.5	48.5	Natural Gas Fired Combined Cycle	NG	CT	7	1993	Operating	TEC	26
58945	EthosEnergy Power Plant Services	54424	Quantum Pasco Power LP	IPP CHP	FL	ST1	CC1	26.5	24.0	24.0	Natural Gas Fired Combined Cycle	NG	CA	7	1993	Operating	TEC	26
49901	Northern Star Generation Services Co LLC	54426	Mulberry Cogeneration Facility	IPP CHP	FL	GT1	CC1	82.0	76.0	80.0	Natural Gas Fired Combined Cycle	NG	CT	5	1994	Operating	FPC	25
49901	Northern Star Generation Services Co LLC	54426	Mulberry Cogeneration Facility	IPP CHP	FL	ST1	CC1	43.3	37.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	7	1994	Operating	FPC	25
14184	Orlando CoGen Ltd LP	54466	Orlando Cogen LP	IPP CHP	FL	GEN1		122.4	120.0	130.0	Natural Gas Fired Combined Cycle	NG	CS	9	1993	Operating	FPC	26
15500	Puget Sound Energy Inc	54476	Sumas Power Plant	Electric Utility	WA	GEN1	CC1	87.8	84.7	96.5	Natural Gas Fired Combined Cycle	NG	CT	3	1993	Operating	PSEI	26
15500	Puget Sound Energy Inc	54476	Sumas Power Plant	Electric Utility	WA	GEN2	CC1	37.7	40.8	40.8	Natural Gas Fired Combined Cycle	NG	CA	3	1993	Operating	PSEI	26
15500	Puget Sound Energy Inc	54537	Ferndale Generating Station	Electric Utility	WA	CT1A	CC1	95.9	86.0	94.0	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	PSEI	25
15500	Puget Sound Energy Inc	54537	Ferndale Generating Station	Electric Utility	WA	CT1B	CC1	95.9	86.0	94.0	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Operating	PSEI	25
15500	Puget Sound Energy Inc	54537	Ferndale Generating Station	Electric Utility	WA	ST1	CC1	93.7	98.0	98.0	Natural Gas Fired Combined Cycle	NG	CA	4	1994	Operating	PSEI	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	1	BLK1	169.2	155.3	196.8	Natural Gas Fired Combined Cycle	NG	CT	10	1994	Operating	NYIS	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	2	BLK1	169.2	155.3	196.8	Natural Gas Fired Combined Cycle	NG	CT	9	1994	Operating	NYIS	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	3	BLK2	169.2	155.3	196.8	Natural Gas Fired Combined Cycle	NG	CT	8	1994	Operating	NYIS	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	4	BLK2	169.5	155.3	196.8	Natural Gas Fired Combined Cycle	NG	CT	9	1994	Operating	NYIS	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	5	BLK1	204.5	167.5	212.3	Natural Gas Fired Combined Cycle	NG	CA	10	1994	Operating	NYIS	25
17254	Sithe/Independence LLC	54547	Sithe Independence Station	IPP CHP	NY	6	BLK2	204.5	167.5	212.3	Natural Gas Fired Combined Cycle	NG	CA	9	1994	Operating	NYIS	25
6529	Exxon Mobil Production Co	54550	ExxonMobil Mobile Bay Onshore	Industrial CHP	AL	901	CC1	0.9	0.9	0.9	Natural Gas Fired Combined Cycle	NG	CA	12	1993	Operating	SOCO	26
6529	Exxon Mobil Production Co	54550	ExxonMobil Mobile Bay Onshore	Industrial CHP	AL	901A	CC1	3.7	3.4	3.6	Natural Gas Fired Combined Cycle	NG	CT	9	1993	Operating	SOCO	26
6529	Exxon Mobil Production Co	54550	ExxonMobil Mobile Bay Onshore	Industrial CHP	AL	901B	CC1	3.7	3.4	3.6	Natural Gas Fired Combined Cycle	NG	CT	9	1993	Operating	SOCO	26
6529	Exxon Mobil Production Co	54550	ExxonMobil Mobile Bay Onshore	Industrial CHP	AL	901C	CC1	3.7	3.4	3.6	Natural Gas Fired Combined Cycle	NG	CT	9	1993	Operating	SOCO	26
16729	Saranac Power Partners LP	54574	Saranac Facility	IPP Non-CHP	NY	GEN1	CA	95.2	82.8	94.5	Natural Gas Fired Combined Cycle	NG	CT	6	1994	Operating	NYIS	25
16729	Saranac Power Partners LP	54574	Saranac Facility	IPP Non-CHP	NY	GEN2	CA	95.2	77.6	90.4	Natural Gas Fired Combined Cycle	NG	CT	6	1994	Operating	NYIS	25
16729	Saranac Power Partners LP	54574	Saranac Facility	IPP Non-CHP	NY	GEN3	CA	95.2	85.6	86.3	Natural Gas Fired Combined Cycle	NG	CA	6	1994	Operating	NYIS	25
56171	Bicent Power	54586	Tanner Street Generation	IPP Non-CHP	MA	VAX	CC1	27.1	17.0	19.0	Natural Gas Fired Combined Cycle	NG	CA	10	1992	Operating	ISNE	27
56171	Bicent Power	54586	Tanner Street Generation	IPP Non-CHP	MA	TRENT	CC1	57.9	58.0	58.0	Natural Gas Fired Combined Cycle	NG	CT	10	2008	Operating	ISNE	11
15253	Power City Partners LP	54592	Massena Energy Facility	IPP Non-CHP	NY	GEN1	CC1	66.5	46.0	56.0	Natural Gas Fired Combined Cycle	NG	CT	7	1992	Operating	NYIS	27
15253	Power City Partners LP	54592	Massena Energy Facility	IPP Non-CHP	NY	GEN2	CC1	35.6	35.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	7	1992	Operating	NYIS	27
16839	Seneca Power Partners LP	54593	Batavia Power Plant	IPP Non-CHP	NY	GEN1	CC01	47.7	34.3	44.3	Natural Gas Fired Combined Cycle	NG	CT	9	1992	Operating	NYIS	27
16839	Seneca Power Partners LP	54593	Batavia Power Plant	IPP Non-CHP	NY	GEN2	CC01	18.5	14.5	14.8	Natural Gas Fired Combined Cycle	NG	CA	9	1992	Operating	NYIS	27
60789	Nautilus Power LLC	54640	NAEA Lakewood LLC	IPP Non-CHP	NJ	GEN1	LCLP	77.9	77.2	84.9	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Standby/	PJM	25

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
60789	Nautilus Power LLC	54640	NAEA Lakewood LLC	IPP Non-CHP	NJ	GEN2	LCLP	77.9	76.2	83.9	Natural Gas Fired Combined Cycle	NG	CT	4	1994	Standby/	PJM	25
60789	Nautilus Power LLC	54640	NAEA Lakewood LLC	IPP Non-CHP	NJ	GEN3	LCLP	81.0	79.7	82.2	Natural Gas Fired Combined Cycle	NG	CA	4	1994	Standby/	PJM	25
3670	FreePort-McMoRan-Corp-Chino Mines	54667	Chino Mines	CHP	NM	7	CTG9	16.5	15.4	15.5	Natural Gas Fired Combined Cycle	NG	CA	10	1959	Standby/	PNM	60
3670	FreePort-McMoRan-Corp-Chino Mines	54667	Chino Mines	CHP	NM	9	CTG9	37.5	35.0	40.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Standby/	PNM	18
5374	Dow Chemical Company-Oyster Creek VIII	54676	Oyster Creek Unit VIII	IPP CHP	TX	G81	CC1	99.0	73.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	10	1994	Operating	ERCO	25
5374	Dow Chemical Company-Oyster Creek VIII	54676	Oyster Creek Unit VIII	IPP CHP	TX	G82	CC1	99.0	73.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	10	1994	Operating	ERCO	25
5374	Dow Chemical Company-Oyster Creek VIII	54676	Oyster Creek Unit VIII	IPP CHP	TX	G83	CC1	99.0	73.0	90.0	Natural Gas Fired Combined Cycle	NG	CT	10	1994	Operating	ERCO	25
5374	Dow Chemical Company-Oyster Creek VIII	54676	Oyster Creek Unit VIII	IPP CHP	TX	G84	CC1	200.9	160.0	160.0	Natural Gas Fired Combined Cycle	NG	CA	10	1994	Operating	ERCO	25
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#1	CC1	8.3	46.2	46.9	Natural Gas Fired Combined Cycle	NG	CT	4	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#2	CC1	8.3			Natural Gas Fired Combined Cycle	NG	CT	4	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#5	CC1	8.3			Natural Gas Fired Combined Cycle	NG	CT	4	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	GT#6	CC1	8.3			Natural Gas Fired Combined Cycle	NG	CT	4	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	ST#1	CC1	9.5			Natural Gas Fired Combined Cycle	NG	CA	8	1989	Operating	PJM	30
56516	Morris Energy Operations Company, LLC	54693	York Generation Company LLC	IPP Non-CHP	PA	ST#2	CC1	9.5			Natural Gas Fired Combined Cycle	NG	CA	8	1989	Operating	PJM	30
49919	Falcon Power Operating Company	54694	Yuma Cogeneration Associates	IPP CHP	AZ	GEN1	YUCG	44.1	35.1	37.4	Natural Gas Fired Combined Cycle	NG	CT	3	1994	Operating	AZPS	25
49919	Falcon Power Operating Company	54694	Yuma Cogeneration Associates	IPP CHP	AZ	GEN2	YUCG	18.5	17.1	16.5	Natural Gas Fired Combined Cycle	NG	CA	3	1994	Operating	AZPS	25
22269	Goal Line LP	54749	Goal Line LP	IPP CHP	CA	CTG	CC1	41.2	40.0	40.0	Natural Gas Fired Combined Cycle	NG	CT	8	1994	Operating	CISO	25
22269	Goal Line LP	54749	Goal Line LP	IPP CHP	CA	STG	CC1	10.2	9.4	9.4	Natural Gas Fired Combined Cycle	NG	CA	8	1994	Operating	CISO	25
8503	Hermiston Generating Co LP	54761	Hermiston Generating Plant	IPP CHP	OR	GEN1	CC1	106.1	80.0	83.0	Natural Gas Fired Combined Cycle	NG	CA	6	1996	Operating	PACW	23
8503	Hermiston Generating Co LP	54761	Hermiston Generating Plant	IPP CHP	OR	GEN2	CC1	204.5	152.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	6	1996	Operating	PACW	23
8503	Hermiston Generating Co LP	54761	Hermiston Generating Plant	IPP CHP	OR	GEN3	CC2	106.1	80.0	83.0	Natural Gas Fired Combined Cycle	NG	CA	6	1996	Operating	PACW	23
8503	Hermiston Generating Co LP	54761	Hermiston Generating Plant	IPP CHP	OR	GEN4	CC2	204.5	152.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	6	1996	Operating	PACW	23
7564	Grays Ferry Cogen Partnership	54785	Grays Ferry Cogeneration	IPP CHP	PA	GEN1	CC1	57.6	56.6	56.6	Natural Gas Fired Combined Cycle	NG	CA	10	1997	Operating	PJM	22
7564	Grays Ferry Cogen Partnership	54785	Grays Ferry Cogeneration	IPP CHP	PA	GEN2	CC1	135.0	114.0	114.0	Natural Gas Fired Combined Cycle	NG	CT	10	1997	Operating	PJM	22
12469	Milford Power LLC	54805	Milford Power LP	IPP Non-CHP	MA	GT-1	ST-1	128.9	107.9	123.6	Natural Gas Fired Combined Cycle	NG	CT	3	1993	Operating	ISNE	26
12469	Milford Power LLC	54805	Milford Power LP	IPP Non-CHP	MA	ST-1	ST-1	120.4	40.1	46.2	Natural Gas Fired Combined Cycle	NG	CA	3	1993	Operating	ISNE	26
13491	New York University	54808	New York University Central Plant	Commercial CHP	NY	T1	CC1	2.4	1.8	1.8	Natural Gas Fired Combined Cycle	NG	CA	1	1984	Operating	NYIS	35
13491	New York University	54808	New York University Central Plant	Commercial CHP	NY	GT1	CC1	5.5	5.5	5.5	Natural Gas Fired Combined Cycle	NG	CT	12	2010	Operating	NYIS	9
13491	New York University	54808	New York University Central Plant	Commercial CHP	NY	GT2	CC1	5.5	5.5	5.5	Natural Gas Fired Combined Cycle	NG	CT	12	2010	Operating	NYIS	9
2172	Brazos Electric Power Coop Inc	54817	Johnson County	Electric Utility	TX	GT-1	CC01	178.2	163.0	174.0	Natural Gas Fired Combined Cycle	NG	CT	9	1996	Operating	ERCO	23
2172	Brazos Electric Power Coop Inc	54817	Johnson County	Electric Utility	TX	ST-1	CC01	104.4	104.0	104.0	Natural Gas Fired Combined Cycle	NG	CA	11	1996	Operating	ERCO	23
14410	KMC Thermo, LLC	54832	Brandywine Power Facility	IPP CHP	MD	1	F701	98.7			Natural Gas Fired Combined Cycle	NG	CT	10	1996	Operating	PJM	23
14410	KMC Thermo, LLC	54832	Brandywine Power Facility	IPP CHP	MD	2	F701	98.7			Natural Gas Fired Combined Cycle	NG	CT	8	1996	Operating	PJM	23
14410	KMC Thermo, LLC	54832	Brandywine Power Facility	IPP CHP	MD	3	F701	91.4	230.0	230.0	Natural Gas Fired Combined Cycle	NG	CA	9	1996	Operating	PJM	23
19876	Virginia Electric & Power Co	54844	Gordonsville Energy LP	Electric Utility	VA	GOR1	G782	97.2	68.4	84.3	Natural Gas Fired Combined Cycle	NG	CT	3	1994	Operating	PJM	25
19876	Virginia Electric & Power Co	54844	Gordonsville Energy LP	Electric Utility	VA	GOR2	G783	97.2	68.4	82.3	Natural Gas Fired Combined Cycle	NG	CT	3	1994	Operating	PJM	25
19876	Virginia Electric & Power Co	54844	Gordonsville Energy LP	Electric Utility	VA	GOR3	G782	53.0	40.6	50.7	Natural Gas Fired Combined Cycle	NG	CA	3	1994	Operating	PJM	25
19876	Virginia Electric & Power Co	54844	Gordonsville Energy LP	Electric Utility	VA	GOR4	G783	53.0	40.6	50.7	Natural Gas Fired Combined Cycle	NG	CA	3	1994	Operating	PJM	25
11651	Martinez Refining Co	54912	Martinez Refining	Industrial CHP	CA	GTG1	CC1	40.0	40.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	11	1995	Operating	CISO	24
11651	Martinez Refining Co	54912	Martinez Refining	Industrial CHP	CA	GTG2	CC1	40.0	40.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	1	1996	Operating	CISO	23
2313	Brooklyn Navy Yard Cogen PLP	54914	Brooklyn Navy Yard Cogeneration	IPP CHP	NY	01	CC1	121.0	90.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	3	1996	Operating	NYIS	23
2313	Brooklyn Navy Yard Cogen PLP	54914	Brooklyn Navy Yard Cogeneration	IPP CHP	NY	02	CC2	121.0	90.0	110.0	Natural Gas Fired Combined Cycle	NG	CT	3	1996	Operating	NYIS	23
2313	Brooklyn Navy Yard Cogen PLP	54914	Brooklyn Navy Yard Cogeneration	IPP CHP	NY	03	CC1	40.0	35.0	38.0	Natural Gas Fired Combined Cycle	NG	CA	6	1996	Operating	NYIS	23
2313	Brooklyn Navy Yard Cogen PLP	54914	Brooklyn Navy Yard Cogeneration	IPP CHP	NY	04	CC2	40.0	35.0	38.0	Natural Gas Fired Combined Cycle	NG	CA	6	1996	Operating	NYIS	23
12455	Michigan Power Limited Partnership	54915	Michigan Power LP	IPP CHP	MI	G001	CC1	58.0	58.0	58.0	Natural Gas Fired Combined Cycle	NG	CA	10	1995	Operating	MISO	24
12455	Michigan Power Limited Partnership	54915	Michigan Power LP	IPP CHP	MI	G101	CC1	80.1	70.0	98.0	Natural Gas Fired Combined Cycle	NG	CT	10	1995	Operating	MISO	24
24008	University of Oregon	54950	Univ of Oregon Central Power Station	Commercial CHP	OR	CTG1	CCS1	7.5	7.5	7.5	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	BPAT	7
24008	University of Oregon	54950	Univ of Oregon Central Power Station	Commercial CHP	OR	STG1	CCS1	3.5	1.5	3.0	Natural Gas Fired Combined Cycle	NG	CA	12	2012	Operating	BPAT	7
55912	Cottage Grove Operating Services LLC	55010	LSP-Cottage Grove LP	IPP CHP	MN	CTG1	CC1	177.3	154.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	10	1997	Operating	MISO	22
55912	Cottage Grove Operating Services LLC	55010	LSP-Cottage Grove LP	IPP CHP	MN	STG1	CC1	106.2	97.0	98.0	Natural Gas Fired Combined Cycle	NG	CA	10	1997	Operating	MISO	22

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55911	Whitewater Operating Services LLC	55011	LSP-Whitewater LP	IPP CHP	WI	CTG1	CC1	177.3	162.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	9	1997	Operating	MISO	22
55911	Whitewater Operating Services LLC	55011	LSP-Whitewater LP	IPP CHP	WI	STG1	CC1	106.2	99.0	97.0	Natural Gas Fired Combined Cycle	NG	CA	9	1997	Operating	MISO	22
55773	Dighton Power, LLC	55026	Dighton Power Plant	IPP Non-CHP	MA	UNT1		200.0	162.8	188.2	Natural Gas Fired Combined Cycle	NG	CS	5	1999	Operating	ISNE	20
12564	SEPG Operating Services, LLC MGC	55040	Mid-Georgia Cogeneration Facility	IPP CHP	GA	CT1	CC01	106.5	101.5	115.0	Natural Gas Fired Combined Cycle	NG	CT	10	1997	Operating	SOCO	22
12564	SEPG Operating Services, LLC MGC	55040	Mid-Georgia Cogeneration Facility	IPP CHP	GA	ST1	CC01	110.0	100.0	100.0	Natural Gas Fired Combined Cycle	NG	CA	12	1997	Operating	SOCO	22
12564	SEPG Operating Services, LLC MGC	55040	Mid-Georgia Cogeneration Facility	IPP CHP	GA	CT2	CC01	106.5	101.5	115.0	Natural Gas Fired Combined Cycle	NG	CT	2	1998	Operating	SOCO	21
1616	Berkshire Power Co LLC	55041	Berkshire Power	IPP Non-CHP	MA	GEN2		289.0	229.3	246.3	Natural Gas Fired Combined Cycle	NG	CS	9	1999	Operating	ISNE	20
2232	Bridgeport Energy LLC	55042	Bridgeport Energy Project	IPP Non-CHP	CT	GEN1	BPE1	170.0	164.0	191.0	Natural Gas Fired Combined Cycle	NG	CT	6	1998	Operating	ISNE	21
2232	Bridgeport Energy LLC	55042	Bridgeport Energy Project	IPP Non-CHP	CT	GEN2	BPE1	170.0	164.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	6	1998	Operating	ISNE	21
2232	Bridgeport Energy LLC	55042	Bridgeport Energy Project	IPP Non-CHP	CT	GEN3	BPE1	180.0	164.0	185.0	Natural Gas Fired Combined Cycle	NG	CA	5	1999	Operating	ISNE	20
6833	Cherokee County Cogen Partners LLC	55043	Cherokee County Cogen	IPP CHP	SC	GT1	CC1	60.0	51.0	66.0	Natural Gas Fired Combined Cycle	NG	CT	7	1998	Operating	DUK	21
6833	Cherokee County Cogen Partners LLC	55043	Cherokee County Cogen	IPP CHP	SC	ST1	CC1	41.2	35.0	35.0	Natural Gas Fired Combined Cycle	NG	CA	7	1998	Operating	DUK	21
11059	Pasadena Cogeneration LP	55047	Pasadena Cogeneration	IPP CHP	TX	CTG1	P1	175.0	155.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	6	1998	Operating	ERCO	21
11059	Pasadena Cogeneration LP	55047	Pasadena Cogeneration	IPP CHP	TX	STG1	P1	85.0	60.0	85.0	Natural Gas Fired Combined Cycle	NG	CA	6	1998	Operating	ERCO	21
11059	Pasadena Cogeneration LP	55047	Pasadena Cogeneration	IPP CHP	TX	CTG2	P2	185.0	165.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
11059	Pasadena Cogeneration LP	55047	Pasadena Cogeneration	IPP CHP	TX	CTG3	P2	185.0	165.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
11059	Pasadena Cogeneration LP	55047	Pasadena Cogeneration	IPP CHP	TX	STG2	P2	185.0	165.0	185.0	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	ERCO	19
55510	Tiverton Power LLC	55048	Tiverton Power Plant	IPP Non-CHP	RI	UNT1	1226	179.3	177.4	203.7	Natural Gas Fired Combined Cycle	NG	CT	3	2000	Operating	ISNE	19
55510	Tiverton Power LLC	55048	Tiverton Power Plant	IPP Non-CHP	RI	UNT2	1226	93.2	90.6	94.9	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	ISNE	19
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	IPP Non-CHP	TX	GTG1	STG1	183.2	155.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ERCO	19
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	IPP Non-CHP	TX	GTG2	STG1	183.2	155.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ERCO	19
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	IPP Non-CHP	TX	GTG3	STG1	183.2	155.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ERCO	19
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	IPP Non-CHP	TX	STG1	STG1	390.1	395.0	395.0	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	ERCO	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	CTG1	CC1	184.5	176.0	184.5	Natural Gas Fired Combined Cycle	NG	CT	8	2000	Operating	TVA	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	CTG2	CC2	184.5	176.0	184.5	Natural Gas Fired Combined Cycle	NG	CT	8	2000	Operating	TVA	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	CTG3	CC3	184.5	176.0	184.5	Natural Gas Fired Combined Cycle	NG	CT	8	2000	Operating	TVA	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	STG1	CC1	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	8	2000	Operating	TVA	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	STG2	CC2	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	8	2000	Operating	TVA	19
17568	Cooperative Energy	55063	Batesville Generation Facility	Electric Utility	MS	STG3	CC3	112.5	110.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	8	2000	Operating	TVA	19
7349	Golden Spread Electric Cooperative, Inc	55065	Mustang Station	Electric Utility	TX	GEN1	CC1	174.2	154.0	154.0	Natural Gas Fired Combined Cycle	NG	CT	6	1999	Operating	SWPP	20
7349	Golden Spread Electric Cooperative, Inc	55065	Mustang Station	Electric Utility	TX	GEN2	CC1	174.2	153.0	153.0	Natural Gas Fired Combined Cycle	NG	CT	6	1999	Operating	SWPP	20
7349	Golden Spread Electric Cooperative, Inc	55065	Mustang Station	Electric Utility	TX	GEN3	CC1	172.6	157.0	157.0	Natural Gas Fired Combined Cycle	NG	CA	4	2000	Operating	SWPP	19
4966	Casco Bay Energy Co LLC	55068	Maine Independence Station	IPP Non-CHP	ME	GEN1	CC1	177.8	155.7	173.5	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ISNE	19
4966	Casco Bay Energy Co LLC	55068	Maine Independence Station	IPP Non-CHP	ME	GEN2	CC1	177.8	156.7	175.1	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ISNE	19
4966	Casco Bay Energy Co LLC	55068	Maine Independence Station	IPP Non-CHP	ME	GEN3	CC1	194.6	177.6	191.4	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	ISNE	19
28764	Pine Bluff Energy LLC	55075	Pine Bluff Energy Center	IPP CHP	AR	CT01	CC01	180.0	145.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	MISO	18
28764	Pine Bluff Energy LLC	55075	Pine Bluff Energy Center	IPP CHP	AR	ST01	CC01	56.0	47.0	52.0	Natural Gas Fired Combined Cycle	NG	CA	8	2001	Operating	MISO	18
5695	Desert Star Energy Center SDG&E	55077	Desert Star Energy Center	Electric Utility	NV	ED01	CC1	170.0	150.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	CISO	19
5695	Desert Star Energy Center SDG&E	55077	Desert Star Energy Center	Electric Utility	NV	ED02	CC1	170.0	150.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	CISO	19
5695	Desert Star Energy Center SDG&E	55077	Desert Star Energy Center	Electric Utility	NV	ED03	CC1	196.0	150.0	170.0	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	CISO	19
12713	Millennium Power Partners LP	55079	Millennium Power	IPP Non-CHP	MA	CT01	CC01	230.0	214.8	246.2	Natural Gas Fired Combined Cycle	NG	CT	4	2001	Operating	ISNE	18
12713	Millennium Power Partners LP	55079	Millennium Power	IPP Non-CHP	MA	ST01	CC01	130.0	120.1	137.7	Natural Gas Fired Combined Cycle	NG	CA	4	2001	Operating	ISNE	18
4464	Crockett Cogeneration	55084	Crockett Cogen Project	IPP CHP	CA	GE1		247.4	247.4	247.4	Natural Gas Fired Combined Cycle	NG	CS	12	1995	Operating	CISO	24
7667	Gregory Power Partners LP	55086	Gregory Power Facility	IPP CHP	TX	GT1A	CC1	166.0	141.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	of service	ERCO	19
7667	Gregory Power Partners LP	55086	Gregory Power Facility	IPP CHP	TX	GT1B	CC1	166.0	140.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	of service	ERCO	19
7667	Gregory Power Partners LP	55086	Gregory Power Facility	IPP CHP	TX	STG	CC1	100.0	85.0	87.0	Natural Gas Fired Combined Cycle	NG	CA	7	2000	of service	ERCO	19
4254	Consumers Energy Co	55087	Zeeland Generating Station	Electric Utility	MI	2A	PHS2	188.7	159.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
4254	Consumers Energy Co	55087	Zeeland Generating Station	Electric Utility	MI	2B	PHS2	188.7	160.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
4254	Consumers Energy Co	55087	Zeeland Generating Station	Electric Utility	MI	2C	PHS2	213.4	207.0	215.0	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	MISO	17
13914	Occidental Chemical Corporation	55089	Taft Cogeneration Facility	Industrial CHP	LA	CT1	CC1	178.5	146.6	178.9	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
13914	Occidental Chemical Corporation	55089	Taft Cogeneration Facility	Industrial CHP	LA	CT2	CC1	178.5	142.9	176.2	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
13914	Occidental Chemical Corporation	55089	Taft Cogeneration Facility	Industrial CHP	LA	CT3	CC1	178.5	150.3	187.2	Natural Gas Fired Combined Cycle	NG	CT	9	2002	Operating	MISO	17
13914	Occidental Chemical Corporation	55089	Taft Cogeneration Facility	Industrial CHP	LA	ST1	CC1	358.7	299.1	323.5	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	MISO	17
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK1		289.0	245.0	245.0	Natural Gas Fired Combined Cycle	NG	CS	5	2000	Operating	ERCO	19
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK2		289.0	245.0	245.0	Natural Gas Fired Combined Cycle	NG	CS	5	2000	Operating	ERCO	19
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK3		289.0	245.0	245.0	Natural Gas Fired Combined Cycle	NG	CS	7	2000	Operating	ERCO	19
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK4		289.0	243.0	243.0	Natural Gas Fired Combined Cycle	NG	CS	9	2000	Operating	ERCO	19
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK5		289.0	256.0	256.0	Natural Gas Fired Combined Cycle	NG	CS	8	2001	Operating	ERCO	18
12501	Midlothian Energy LLC	55091	Midlothian Energy Facility	IPP Non-CHP	TX	STK6		289.0	260.0	260.0	Natural Gas Fired Combined Cycle	NG	CS	9	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	CTG1	BLK1	176.0	163.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ERCO	19
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	CTG2	BLK1	176.0	163.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	ERCO	19
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	CTG3	BLK2	176.0	163.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	ERCO	19
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	CTG4	BLK2	176.0	163.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	ERCO	19
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	STG1	BLK1	204.3	200.6	210.0	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	ERCO	19
60477	LaFrontera Holdings LLC	55097	Lamar Power Project	IPP Non-CHP	TX	STG2	BLK2	204.3	200.6	210.0	Natural Gas Fired Combined Cycle	NG	CA	5	2000	Operating	ERCO	19
54821	Rumford Power	55100	Rumford Power, Inc	IPP Non-CHP	ME	UNT1	CC1	179.4	164.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	Operating	ISNE	19
54821	Rumford Power	55100	Rumford Power, Inc	IPP Non-CHP	ME	UNT2	CC1	95.1	90.0	88.0	Natural Gas Fired Combined Cycle	NG	CA	7	2000	Operating	ISNE	19
14372	Pacific Klamath Energy Inc	55103	Klamath Cogeneration Plant	IPP CHP	OR	CT1	CC1	161.5	155.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	PACW	18
14372	Pacific Klamath Energy Inc	55103	Klamath Cogeneration Plant	IPP CHP	OR	CT2	CC1	161.5	155.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	PACW	18
14372	Pacific Klamath Energy Inc	55103	Klamath Cogeneration Plant	IPP CHP	OR	ST1	CC1	178.5	180.0	190.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	PACW	18
16668	Sabine Cogen LP	55104	Sabine Cogen	IPP CHP	TX	CTG1	CC1	37.4	33.4	35.2	Natural Gas Fired Combined Cycle	NG	CT	1	2000	Operating	MISO	19
16668	Sabine Cogen LP	55104	Sabine Cogen	IPP CHP	TX	CTG2	CC1	37.4	33.4	35.2	Natural Gas Fired Combined Cycle	NG	CT	1	2000	Operating	MISO	19
16668	Sabine Cogen LP	55104	Sabine Cogen	IPP CHP	TX	STG	CC1	31.7	22.5	22.9	Natural Gas Fired Combined Cycle	NG	CA	1	2000	of service	MISO	19
6832	RISEC Operating Services	55107	Rhode Island State Energy Center	IPP Non-CHP	RI	CTG1	CC1	196.0	168.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ISNE	17
6832	RISEC Operating Services	55107	Rhode Island State Energy Center	IPP Non-CHP	RI	CTG2	CC1	196.0	168.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ISNE	17
6832	RISEC Operating Services	55107	Rhode Island State Energy Center	IPP Non-CHP	RI	STG1	CC1	204.0	218.0	218.0	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	ISNE	17
22650	Calpine Corp-Sutter	55112	Sutter Energy Center	IPP Non-CHP	CA	CT01	CC1	212.0	175.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	WALC	18
22650	Calpine Corp-Sutter	55112	Sutter Energy Center	IPP Non-CHP	CA	CT02	CC1	212.0	175.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	WALC	18
22650	Calpine Corp-Sutter	55112	Sutter Energy Center	IPP Non-CHP	CA	ST01	CC1	212.0	180.0	185.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	WALC	18
14306	Eagle 2 US LLC	55117	RS Cogen	Industrial CHP	LA	RS-4	CC1	103.0	80.0	80.0	Natural Gas Fired Combined Cycle	NG	CA	12	2002	Operating	MISO	17
14306	Eagle 2 US LLC	55117	RS Cogen	Industrial CHP	LA	RS-5	CC1	195.0	167.7	183.3	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	MISO	17
14306	Eagle 2 US LLC	55117	RS Cogen	Industrial CHP	LA	RS-6	CC1	195.0	167.7	183.3	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	MISO	17
2877	Calpine Corp-Magic Valley	55123	Magic Valley Generating Station	IPP Non-CHP	TX	CTG1	STG	267.0	221.0	232.0	Natural Gas Fired Combined Cycle	NG	CT	2	2002	Operating	ERCO	17
2877	Calpine Corp-Magic Valley	55123	Magic Valley Generating Station	IPP Non-CHP	TX	CTG2	STG	267.0	221.0	232.0	Natural Gas Fired Combined Cycle	NG	CT	2	2002	Operating	ERCO	17
2877	Calpine Corp-Magic Valley	55123	Magic Valley Generating Station	IPP Non-CHP	TX	STG	STG	267.0	240.0	253.0	Natural Gas Fired Combined Cycle	NG	CA	2	2002	Operating	ERCO	17
56090	Star West Gen Griffith Energy LLC	55124	Griffith Energy LLC	IPP Non-CHP	AZ	CTG1	1111	176.6	147.0	147.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	GRIF	17
56090	Star West Gen Griffith Energy LLC	55124	Griffith Energy LLC	IPP Non-CHP	AZ	CTG2	1111	176.6	147.0	147.0	Natural Gas Fired Combined Cycle	NG	CT	1	2002	Operating	GRIF	17
56090	Star West Gen Griffith Energy LLC	55124	Griffith Energy LLC	IPP Non-CHP	AZ	STG	1111	301.8	276.0	276.0	Natural Gas Fired Combined Cycle	NG	CA	1	2002	Operating	GRIF	17
12568	Milford Power Co LLC	55126	Milford Power Project	IPP Non-CHP	CT	CA01		289.0	270.9	295.6	Natural Gas Fired Combined Cycle	NG	CS	2	2004	Operating	ISNE	15
12568	Milford Power Co LLC	55126	Milford Power Project	IPP Non-CHP	CT	CA02		289.0	266.7	289.7	Natural Gas Fired Combined Cycle	NG	CS	5	2004	Operating	ISNE	15
16572	Salt River Project	55129	Desert Basin	Electric Utility	AZ	CTG1	STG3	187.0	162.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	10	2001	Operating	SRP	18
16572	Salt River Project	55129	Desert Basin	Electric Utility	AZ	CTG2	STG3	187.0	162.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	10	2001	Operating	SRP	18
16572	Salt River Project	55129	Desert Basin	Electric Utility	AZ	STG	STG3	272.1	253.0	269.0	Natural Gas Fired Combined Cycle	NG	CA	10	2001	Operating	SRP	18
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	CTG1	KEN1	180.0	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	3	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	CTG2	KEN2	180.0	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	CTG3	KEN3	180.0	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	CTG4	KEN4	180.0	160.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	STG1	KEN1	134.0	125.0	125.0	Natural Gas Fired Combined Cycle	NG	CA	3	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	STG2	KEN2	134.0	125.0	125.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	PJM	17
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	STG3	KEN3	134.0	125.0	125.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	PJM	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
57141	Dynegy Kendall Energy LLC	55131	Kendall County Generation Facility	IPP Non-CHP	IL	STG4	KEN4	134.0	125.0	125.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	PJM	17
18518	Tenaska Gateway Partners Ltd	55132	Tenaska Gateway Generating Station	IPP Non-CHP	TX	GTG1	STG1	183.2	148.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
18518	Tenaska Gateway Partners Ltd	55132	Tenaska Gateway Generating Station	IPP Non-CHP	TX	GTG2	STG1	183.2	149.0	169.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
18518	Tenaska Gateway Partners Ltd	55132	Tenaska Gateway Generating Station	IPP Non-CHP	TX	GTG3	STG1	183.2	148.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
18518	Tenaska Gateway Partners Ltd	55132	Tenaska Gateway Generating Station	IPP Non-CHP	TX	STG1	STG1	390.0	397.0	397.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	ERCO	18
16604	City of San Antonio - (TX)	55137	Rio Nogales Power Project	Electric Utility	TX	CTG1	CC1	189.0	154.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
16604	City of San Antonio - (TX)	55137	Rio Nogales Power Project	Electric Utility	TX	CTG2	CC1	189.0	154.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
16604	City of San Antonio - (TX)	55137	Rio Nogales Power Project	Electric Utility	TX	CTG3	CC1	189.0	154.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
16604	City of San Antonio - (TX)	55137	Rio Nogales Power Project	Electric Utility	TX	STG1	CC1	373.2	323.0	323.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	ERCO	17
6035	Exelon Power	55139	Wolf Hollow I LP	IPP Non-CHP	TX	CTG1	BLK1	243.9	212.5	249.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	ERCO	16
6035	Exelon Power	55139	Wolf Hollow I LP	IPP Non-CHP	TX	CTG2	BLK1	243.9	212.5	249.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	ERCO	16
6035	Exelon Power	55139	Wolf Hollow I LP	IPP Non-CHP	TX	ST	BLK1	300.6	280.0	293.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	ERCO	16
1074	Hays Energy, LLC	55144	Hays Energy Project	IPP Non-CHP	TX	U1		241.7	215.0	230.0	Natural Gas Fired Combined Cycle	NG	CS	5	2002	Operating	ERCO	17
1074	Hays Energy, LLC	55144	Hays Energy Project	IPP Non-CHP	TX	U2		241.7	215.0	230.0	Natural Gas Fired Combined Cycle	NG	CS	4	2002	Operating	ERCO	17
1074	Hays Energy, LLC	55144	Hays Energy Project	IPP Non-CHP	TX	U3		252.8	224.0	236.0	Natural Gas Fired Combined Cycle	NG	CS	8	2002	Operating	ERCO	17
1074	Hays Energy, LLC	55144	Hays Energy Project	IPP Non-CHP	TX	U4		252.8	227.0	241.0	Natural Gas Fired Combined Cycle	NG	CS	8	2002	Operating	ERCO	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	CTG1	G841	179.3	155.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	2	2002	Operating	SWPP	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	CTG2	G842	179.3	155.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	2	2002	Operating	SWPP	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	CTG3	G843	179.3	155.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	2	2002	Operating	SWPP	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	STG1	G841	122.0	106.0	106.0	Natural Gas Fired Combined Cycle	NG	CA	2	2002	Operating	SWPP	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	STG2	G842	122.0	106.0	106.0	Natural Gas Fired Combined Cycle	NG	CA	2	2002	Operating	SWPP	17
7597	Green Country OP Services LLC	55146	Green Country Energy LLC	IPP Non-CHP	OK	STG3	G843	122.0	106.0	106.0	Natural Gas Fired Combined Cycle	NG	CA	2	2002	Operating	SWPP	17
10576	Lake Road Generating Co LP	55149	Lake Road Generating Plant	IPP Non-CHP	CT	U1		280.0	270.8	290.9	Natural Gas Fired Combined Cycle	NG	CS	3	2002	Operating	ISNE	17
10576	Lake Road Generating Co LP	55149	Lake Road Generating Plant	IPP Non-CHP	CT	U2		280.0	275.0	291.8	Natural Gas Fired Combined Cycle	NG	CS	3	2002	Operating	ISNE	17
10576	Lake Road Generating Co LP	55149	Lake Road Generating Plant	IPP Non-CHP	CT	U3		280.0	286.7	312.4	Natural Gas Fired Combined Cycle	NG	CS	5	2002	Operating	ISNE	17
61173	CXA La Paloma LLC	55151	La Paloma Generating Plant	IPP Non-CHP	CA	GEN1		300.0	243.7	258.6	Natural Gas Fired Combined Cycle	NG	CS	1	2003	Operating	CISO	16
61173	CXA La Paloma LLC	55151	La Paloma Generating Plant	IPP Non-CHP	CA	GEN2		300.0	241.6	259.7	Natural Gas Fired Combined Cycle	NG	CS	1	2003	Operating	CISO	16
61173	CXA La Paloma LLC	55151	La Paloma Generating Plant	IPP Non-CHP	CA	GEN3		300.0	237.4	259.9	Natural Gas Fired Combined Cycle	NG	CS	3	2003	Operating	CISO	16
61173	CXA La Paloma LLC	55151	La Paloma Generating Plant	IPP Non-CHP	CA	GEN4		300.0	242.7	249.3	Natural Gas Fired Combined Cycle	NG	CS	3	2003	Operating	CISO	16
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	CTG1	STG1	171.1	148.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	10	2000	Operating	ERCO	19
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	CTG2	STG1	171.1	148.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	10	2000	Operating	ERCO	19
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	CTG3	STG2	171.1	148.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	ERCO	19
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	CTG4	STG2	171.1	148.0	167.0	Natural Gas Fired Combined Cycle	NG	CT	12	2000	Operating	ERCO	19
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	STG1	STG1	201.9	197.0	203.0	Natural Gas Fired Combined Cycle	NG	CA	10	2000	Operating	ERCO	19
57045	Guadalupe Power Partners LP	55153	Guadalupe Generating Station	IPP Non-CHP	TX	STG2	STG2	201.9	197.0	203.0	Natural Gas Fired Combined Cycle	NG	CA	10	2000	Operating	ERCO	19
11269	Lower Colorado River Authority	55154	Lost Pines 1 Power Project	Electric Utility	TX	CTA	CC1	202.5	169.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	ERCO	18
11269	Lower Colorado River Authority	55154	Lost Pines 1 Power Project	Electric Utility	TX	CTB	CC1	202.5	169.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	ERCO	18
11269	Lower Colorado River Authority	55154	Lost Pines 1 Power Project	Electric Utility	TX	ST	CC1	204.0	172.0	184.0	Natural Gas Fired Combined Cycle	NG	CA	5	2001	Operating	ERCO	18
49768	Bastrop Energy Partners, LP	55168	Bastrop Energy Center	IPP Non-CHP	TX	0001	CC1	188.2	149.0	164.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
49768	Bastrop Energy Partners, LP	55168	Bastrop Energy Center	IPP Non-CHP	TX	0002	CC1	188.2	149.0	164.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
49768	Bastrop Energy Partners, LP	55168	Bastrop Energy Center	IPP Non-CHP	TX	0003	CC1	242.3	227.0	221.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	ERCO	17
88	Granite Ridge Energy LLC	55170	Granite Ridge	IPP Non-CHP	NH	CT11	CC1	260.0	222.0	263.0	Natural Gas Fired Combined Cycle	NG	CT	3	2003	Operating	ISNE	16
88	Granite Ridge Energy LLC	55170	Granite Ridge	IPP Non-CHP	NH	CT12	CC1	260.0	222.0	263.0	Natural Gas Fired Combined Cycle	NG	CT	3	2003	Operating	ISNE	16
88	Granite Ridge Energy LLC	55170	Granite Ridge	IPP Non-CHP	NH	STG	CC1	270.0	234.0	271.0	Natural Gas Fired Combined Cycle	NG	CA	3	2003	Operating	ISNE	16
55899	Calpine Bosque Energy Center LLC	55172	Bosque County Peaking	IPP Non-CHP	TX	GT-1	G125	154.0	154.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	Operating	ERCO	19
55899	Calpine Bosque Energy Center LLC	55172	Bosque County Peaking	IPP Non-CHP	TX	GT-2	G125	154.0	154.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	7	2000	Operating	ERCO	19
55899	Calpine Bosque Energy Center LLC	55172	Bosque County Peaking	IPP Non-CHP	TX	GT-3	G641	154.0	154.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	ERCO	18
55899	Calpine Bosque Energy Center LLC	55172	Bosque County Peaking	IPP Non-CHP	TX	ST-4	G641	95.0	86.0	88.0	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	ERCO	18
55899	Calpine Bosque Energy Center LLC	55172	Bosque County Peaking	IPP Non-CHP	TX	ST-5	G125	250.0	200.0	220.0	Natural Gas Fired Combined Cycle	NG	CA	1	2010	Operating	ERCO	9
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	CT11	PB01	215.1	170.2		Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	CT12	PB01	215.1	169.9		Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	CT24	PB02	215.1	152.2	168.2	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	CT25	PB02	215.1	157.3	173.8	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	ST13	PB01	264.4	218.8		Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
3265	Cleco Power LLC	55173	Acadia Energy Center	Electric Utility	LA	ST26	PB02	264.4	241.1	241.4	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	MISO	17
49791	Eastman Cogeneration LP	55176	Eastman Cogeneration Facility	IPP CHP	TX	GEN1	CC1	170.0	153.7	168.3	Natural Gas Fired Combined Cycle	NG	CT	4	2001	Operating	SWPP	18
49791	Eastman Cogeneration LP	55176	Eastman Cogeneration Facility	IPP CHP	TX	GEN2	CC1	170.0	146.2	159.8	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	SWPP	18
49791	Eastman Cogeneration LP	55176	Eastman Cogeneration Facility	IPP CHP	TX	GEN3	CC1	127.7	109.8	120.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	SWPP	18
50157	South Point Energy Center LLC	55177	South Point Energy Center	IPP Non-CHP	AZ	A	CC1	236.0	180.0	193.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	WALC	18
50157	South Point Energy Center LLC	55177	South Point Energy Center	IPP Non-CHP	AZ	B	CC1	236.0	180.0	193.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	of service	WALC	18
50157	South Point Energy Center LLC	55177	South Point Energy Center	IPP Non-CHP	AZ	ST1	CC1	236.0	190.0	200.0	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	WALC	18
54915	Dogwood Power Management, LLC	55178	Dogwood Energy Facility	IPP Non-CHP	MO	CT-1	CC1	180.0	180.2	196.9	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	SWPP	18
54915	Dogwood Power Management, LLC	55178	Dogwood Energy Facility	IPP Non-CHP	MO	CT-2	CC1	180.0	177.7	195.5	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	SWPP	18
54915	Dogwood Power Management, LLC	55178	Dogwood Energy Facility	IPP Non-CHP	MO	ST-1	CC1	270.0	254.5	284.8	Natural Gas Fired Combined Cycle	NG	CA	2	2002	Operating	SWPP	17
15708	Rathdrum Operating Services Co., Inc.	55179	Rathdrum Power LLC	IPP Non-CHP	ID	CTG1	CC1	179.4	150.0	172.0	Natural Gas Fired Combined Cycle	NG	CT	9	2001	Operating	AVA	18
15708	Rathdrum Operating Services Co., Inc.	55179	Rathdrum Power LLC	IPP Non-CHP	ID	STG1	CC1	122.1	98.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	9	2001	Operating	AVA	18
18320	Sunrise Power Co LLC	55182	Sunrise Power LLC	IPP Non-CHP	CA	X718	CC1	167.7	150.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	CISO	18
18320	Sunrise Power Co LLC	55182	Sunrise Power LLC	IPP Non-CHP	CA	X719	CC1	167.7	150.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	CISO	18
18320	Sunrise Power Co LLC	55182	Sunrise Power LLC	IPP Non-CHP	CA	STG	CC1	270.0	245.0	270.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	CISO	16
49893	Invenergy Services LLC	55183	Nelson Energy Center	IPP Non-CHP	IL	CT1	BLK1	181.9	168.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	5	2015	Operating	PJM	4
49893	Invenergy Services LLC	55183	Nelson Energy Center	IPP Non-CHP	IL	CT2	BLK2	179.4	168.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	5	2015	Operating	PJM	4
49893	Invenergy Services LLC	55183	Nelson Energy Center	IPP Non-CHP	IL	ST1	BLK1	133.1	125.0	128.0	Natural Gas Fired Combined Cycle	NG	CA	5	2015	Operating	PJM	4
49893	Invenergy Services LLC	55183	Nelson Energy Center	IPP Non-CHP	IL	ST2	BLK2	133.1	125.0	128.0	Natural Gas Fired Combined Cycle	NG	CA	5	2015	Operating	PJM	4
56380	EIF Channelview Cogeneration LLC	55187	Channelview Cogeneration Plant	IPP CHP	TX	GT4	CC1	192.1	168.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	ERCO	18
56380	EIF Channelview Cogeneration LLC	55187	Channelview Cogeneration Plant	IPP CHP	TX	GT1	CC1	192.1	169.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
56380	EIF Channelview Cogeneration LLC	55187	Channelview Cogeneration Plant	IPP CHP	TX	GT2	CC1	192.1	163.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
56380	EIF Channelview Cogeneration LLC	55187	Channelview Cogeneration Plant	IPP CHP	TX	GT3	CC1	192.1	166.0	179.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
56380	EIF Channelview Cogeneration LLC	55187	Channelview Cogeneration Plant	IPP CHP	TX	ST1	CC1	149.9	144.0	144.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	ERCO	17
4210	Cordova Energy Co LLC	55188	Cordova Energy	IPP Non-CHP	IL	PT11	CC1	210.0	165.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	PJM	18
4210	Cordova Energy Co LLC	55188	Cordova Energy	IPP Non-CHP	IL	PT21	CC1	210.0	165.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	PJM	18
4210	Cordova Energy Co LLC	55188	Cordova Energy	IPP Non-CHP	IL	PT31	CC1	191.2	191.2	191.2	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	PJM	18
55649	Ontelaunee Energy Center	55193	Ontelaunee Energy Center	IPP Non-CHP	PA	CTG1	CC01	250.0	180.0	203.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	PJM	17
55649	Ontelaunee Energy Center	55193	Ontelaunee Energy Center	IPP Non-CHP	PA	CTG2	CC01	250.0	180.0	203.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	PJM	17
55649	Ontelaunee Energy Center	55193	Ontelaunee Energy Center	IPP Non-CHP	PA	STG	CC01	228.0	180.0	218.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	PJM	17
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	CTG1	CCC1	161.0	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	CTG2	CCC2	161.0	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	CTG3	CCC3	161.0	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	STG1	CCC1	106.0	98.0	105.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	STG2	CCC2	106.0	98.0	105.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55197	Caledonia	Electric Utility	MS	STG3	CCC3	106.0	98.0	105.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	TVA	16
58517	SWG Arapahoe, LLC	55200	Arapahoe Combustion Turbine Project	IPP Non-CHP	CO	UN5	A567	71.1	39.0	39.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	PSCO	19
58517	SWG Arapahoe, LLC	55200	Arapahoe Combustion Turbine Project	IPP Non-CHP	CO	UN6	A567	71.1	39.0	39.0	Natural Gas Fired Combined Cycle	NG	CT	5	2000	Operating	PSCO	19
58517	SWG Arapahoe, LLC	55200	Arapahoe Combustion Turbine Project	IPP Non-CHP	CO	UN7	A567	51.8	44.5	48.6	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	PSCO	17
4383	Corpus Christi Cogeneration LLC	55206	Corpus Christi Energy Center	IPP CHP	TX	CT1	CCEC	198.9	152.0	159.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ERCO	17
4383	Corpus Christi Cogeneration LLC	55206	Corpus Christi Energy Center	IPP CHP	TX	CT2	CCEC	198.9	152.0	159.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ERCO	17
4383	Corpus Christi Cogeneration LLC	55206	Corpus Christi Energy Center	IPP CHP	TX	ST1	CCEC	195.5	165.0	165.0	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	ERCO	17
15473	Public Service Co of NM	55210	Afton Generating Station	Electric Utility	NM	0001	CC1	177.0	141.0	149.0	Natural Gas Fired Combined Cycle	NG	CT	11	2002	Operating	PNM	17
15473	Public Service Co of NM	55210	Afton Generating Station	Electric Utility	NM	0002	CC1	110.0	94.6	103.4	Natural Gas Fired Combined Cycle	NG	CA	10	2007	Operating	PNM	12
641	ANP Bellingham Energy Company LLC	55211	ANP Bellingham Energy Project	IPP Non-CHP	MA	U1		289.0	270.3	299.1	Natural Gas Fired Combined Cycle	NG	CS	11	2002	Operating	ISNE	17
641	ANP Bellingham Energy Company LLC	55211	ANP Bellingham Energy Project	IPP Non-CHP	MA	U2		289.0	264.9	298.2	Natural Gas Fired Combined Cycle	NG	CS	12	2002	Operating	ISNE	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
656	ANP Blackstone Energy Company LLC	55212	ANP Blackstone Energy Project	IPP Non-CHP	MA	U1		289.0	247.8	279.7	Natural Gas Fired Combined Cycle	NG	CS	6	2001	Operating	ISNE	18
656	ANP Blackstone Energy Company LLC	55212	ANP Blackstone Energy Project	IPP Non-CHP	MA	U2		289.0	248.7	278.8	Natural Gas Fired Combined Cycle	NG	CS	7	2001	Operating	ISNE	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	CTG1	BLK1	176.0	149.0	157.9	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	CTG2	BLK1	176.0	143.0	151.5	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	CTG3	BLK2	176.0	145.3	154.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	CTG4	BLK2	176.0	143.7	152.3	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	STG1	BLK1	224.4	204.9	212.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	ERCO	18
60477	LaFrontera Holdings LLC	55215	Odessa-Ector Power Plant	IPP Non-CHP	TX	STG2	BLK2	224.4	204.9	212.0	Natural Gas Fired Combined Cycle	NG	CA	8	2001	Operating	ERCO	18
54755	Morris Cogeneration LLC	55216	Morris Cogeneration LLC	IPP CHP	IL	UNT1	MCG1	45.3	44.0	44.0	Natural Gas Fired Combined Cycle	NG	CT	11	1998	Operating	PJM	21
54755	Morris Cogeneration LLC	55216	Morris Cogeneration LLC	IPP CHP	IL	UNT2	MCG1	45.3	44.0	44.0	Natural Gas Fired Combined Cycle	NG	CT	11	1998	Operating	PJM	21
54755	Morris Cogeneration LLC	55216	Morris Cogeneration LLC	IPP CHP	IL	UNT3	MCG1	39.0	44.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	11	1998	Operating	PJM	21
54755	Morris Cogeneration LLC	55216	Morris Cogeneration LLC	IPP CHP	IL	STG1	MCG1	82.9	62.0	62.0	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	PJM	19
2843	Los Medanos Energy Center LLC	55217	Los Medanos Energy Center	IPP CHP	CA	CTG1	CC1	198.9	165.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	CISO	18
2843	Los Medanos Energy Center LLC	55217	Los Medanos Energy Center	IPP CHP	CA	CTG2	CC1	198.9	165.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	8	2001	Operating	CISO	18
2843	Los Medanos Energy Center LLC	55217	Los Medanos Energy Center	IPP CHP	CA	STG3	CC1	280.5	237.0	244.0	Natural Gas Fired Combined Cycle	NG	CA	8	2001	Operating	CISO	18
12685	Entergy Mississippi Inc	55218	Hinds Energy Facility	Electric Utility	MS	H01	PB01	176.6			Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	MISO	18
12685	Entergy Mississippi Inc	55218	Hinds Energy Facility	Electric Utility	MS	H02	PB01	176.6			Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	MISO	18
12685	Entergy Mississippi Inc	55218	Hinds Energy Facility	Electric Utility	MS	H03	PB01	198.1	459.8	494.8	Natural Gas Fired Combined Cycle	NG	CA	5	2001	Operating	MISO	18
12685	Entergy Mississippi Inc	55220	Attala	Electric Utility	MS	A01	PB01	176.6			Natural Gas Fired Combined Cycle	NG	CT	3	2001	Operating	MISO	18
12685	Entergy Mississippi Inc	55220	Attala	Electric Utility	MS	A02	PB01	176.6			Natural Gas Fired Combined Cycle	NG	CT	3	2001	Operating	MISO	18
12685	Entergy Mississippi Inc	55220	Attala	Electric Utility	MS	A03	PB01	198.1	453.1	492.0	Natural Gas Fired Combined Cycle	NG	CA	3	2001	Operating	MISO	18
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G1	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G2	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G3	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G4	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G5	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G6	OSW1	51.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G7	OSW1	83.5	76.0	76.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G8	OSW1	105.0	95.0	95.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
807	Arkansas Electric Coop Corp	55221	Harry L. Oswald	Electric Utility	AR	G9	OSW1	105.0	95.0	95.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
5761	Ennis Power Company LLC	55223	Ennis Power Company LLC	IPP Non-CHP	TX	GT1	CC1	285.0	245.1	267.9	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
5761	Ennis Power Company LLC	55223	Ennis Power Company LLC	IPP Non-CHP	TX	ST1	CC1	133.0	114.4	125.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	ERCO	17
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	CTG1	BLK1	176.0	149.3	160.1	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SWPP	17
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	CTG2	BLK1	176.0	149.3	160.1	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SWPP	17
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	STG1	BLK1	255.0	244.6	243.9	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	SWPP	17
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	CTG3	BLK2	176.0	149.3	160.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SWPP	16
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	CTG4	BLK2	176.0	149.3	160.1	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SWPP	16
2897	Oneta Power LLC	55225	Oneta Energy Center	IPP Non-CHP	OK	STG2	BLK2	255.0	244.6	243.9	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SWPP	16
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	GT1	PB1	166.7	153.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	GT2	PB1	166.7	153.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	GT3	PB2	166.7	149.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	ERCO	17
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	GT4	PB2	166.7	149.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	ERCO	17
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	ST3	PB1	184.6	177.0	184.6	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	ERCO	17
6763	Freestone Power Generation LLC	55226	Freestone Energy Center	IPP Non-CHP	TX	ST6	PB2	184.6	172.0	184.6	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	ERCO	17
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	CT1	CC01	170.0	165.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	ERCO	13
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	CT2	CC01	170.0	165.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	ERCO	13
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	ST1	CC01	300.0	290.5	300.0	Natural Gas Fired Combined Cycle	NG	CA	2	2006	Operating	ERCO	13
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	CT3	CC02	170.0	165.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	3	2011	Operating	ERCO	8
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	CT4	CC02	170.0	165.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	3	2011	Operating	ERCO	8
2172	Brazos Electric Power Coop Inc	55230	Jack County	Electric Utility	TX	ST2	CC02	300.0	290.5	300.0	Natural Gas Fired Combined Cycle	NG	CA	3	2011	Operating	ERCO	8

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
27031	Liberty Electric Power LLC	55231	Liberty Electric Power Plant	IPP Non-CHP	PA	GTG1	CC1	186.0	169.1	169.1	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	PJM	17
27031	Liberty Electric Power LLC	55231	Liberty Electric Power Plant	IPP Non-CHP	PA	GTG2	CC1	186.0	169.1	169.1	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	PJM	17
27031	Liberty Electric Power LLC	55231	Liberty Electric Power Plant	IPP Non-CHP	PA	STG	CC1	242.0	223.8	223.8	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	PJM	17
22131	Red Oak Operating Services LLC	55239	Red Oak Power LLC	IPP Non-CHP	NJ	0001	CC1	180.2	165.3	182.7	Natural Gas Fired Combined Cycle	NG	CT	3	2002	Operating	PJM	17
22131	Red Oak Operating Services LLC	55239	Red Oak Power LLC	IPP Non-CHP	NJ	0002	CC1	180.2	165.3	182.7	Natural Gas Fired Combined Cycle	NG	CT	3	2002	Operating	PJM	17
22131	Red Oak Operating Services LLC	55239	Red Oak Power LLC	IPP Non-CHP	NJ	0003	CC1	180.2	165.3	182.7	Natural Gas Fired Combined Cycle	NG	CT	3	2002	Operating	PJM	17
22131	Red Oak Operating Services LLC	55239	Red Oak Power LLC	IPP Non-CHP	NJ	0004	CC1	280.5	270.0	275.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	PJM	17
12739	Mobile Energy LLC	55241	Hog Bayou Energy Center	IPP Non-CHP	AL	CT01	CC1	200.0	155.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	SOCO	18
12739	Mobile Energy LLC	55241	Hog Bayou Energy Center	IPP Non-CHP	AL	ST01	CC1	80.0	75.0	75.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	SOCO	18
54692	Santa Rosa Energy Center LLC	55242	Santa Rosa Energy Center	IPP CHP	FL	CT01	CC1	200.0	161.4	173.4	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SOCO	16
54692	Santa Rosa Energy Center LLC	55242	Santa Rosa Energy Center	IPP CHP	FL	ST01	CC1	74.5	74.5	74.5	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SOCO	16
56195	BP Alternative Energy	55259	Whiting Clean Energy	IPP CHP	IN	CT1	CC1	181.9	150.0	172.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	MISO	17
56195	BP Alternative Energy	55259	Whiting Clean Energy	IPP CHP	IN	CT2	CC1	181.9	150.0	172.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	MISO	17
56195	BP Alternative Energy	55259	Whiting Clean Energy	IPP CHP	IN	ST1	CC1	213.0	213.0	213.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	MISO	17
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	CTG1	SCC1	179.3	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	CTG2	SCC2	179.3	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	CTG3	SCC3	179.3	157.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	STG1	SCC1	122.0	103.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	STG2	SCC2	122.0	103.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55269	TVA Southaven Combined Cycle	Electric Utility	MS	STG3	SCC3	122.0	103.0	110.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	TVA	16
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	7EA	CC1	79.0	70.0	70.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM1	CC1	60.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM2	CC1	60.0	46.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM3	CC1	60.0	46.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM4	CC1	60.0	45.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM5	CC1	60.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	LM6	CC1	60.0	46.0	46.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	ST1	CC1	105.0	101.0	101.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
4254	Consumers Energy Co	55270	Jackson Generating Station	Electric Utility	MI	ST2	CC1	105.0	99.0	99.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
31386	Tenaska Alabama Partners LP	55271	Station	IPP Non-CHP	AL	GTG1	STG1	183.1	152.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	SOCO	17
31386	Tenaska Alabama Partners LP	55271	Station	IPP Non-CHP	AL	GTG2	STG1	183.1	152.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	SOCO	17
31386	Tenaska Alabama Partners LP	55271	Station	IPP Non-CHP	AL	GTG3	STG1	183.1	149.0	160.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	SOCO	17
31386	Tenaska Alabama Partners LP	55271	Station	IPP Non-CHP	AL	STG1	STG1	390.1	392.0	394.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	SOCO	17
56812	Arlington Valley LLC	55282	Arlington Valley Energy Facility	IPP Non-CHP	AZ	CTG1	CC1	198.0	162.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	DEAA	17
56812	Arlington Valley LLC	55282	Arlington Valley Energy Facility	IPP Non-CHP	AZ	CTG2	CC1	198.0	163.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	DEAA	17
56812	Arlington Valley LLC	55282	Arlington Valley Energy Facility	IPP Non-CHP	AZ	STG1	CC1	317.0	255.0	255.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	DEAA	17
3989	City of Colorado Springs - (CO)	55283	Front Range Power Plant	Electric Utility	CO	1	CC1	154.0	135.0	140.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	WACM	16
3989	City of Colorado Springs - (CO)	55283	Front Range Power Plant	Electric Utility	CO	2	CC1	154.0	135.0	140.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	WACM	16
3989	City of Colorado Springs - (CO)	55283	Front Range Power Plant	Electric Utility	CO	3	CC1	233.0	190.0	200.0	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	WACM	16
2929	Decatur Energy Center LLC	55292	Decatur Energy Center	IPP Non-CHP	AL	CTG1	CC01	210.8	155.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	TVA	17
2929	Decatur Energy Center LLC	55292	Decatur Energy Center	IPP Non-CHP	AL	CTG2	CC01	210.8	155.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	TVA	17
2929	Decatur Energy Center LLC	55292	Decatur Energy Center	IPP Non-CHP	AL	STG1	CC01	270.0	260.0	265.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	TVA	17
2929	Decatur Energy Center LLC	55292	Decatur Energy Center	IPP Non-CHP	AL	CTG3	CC01	210.8	155.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
29122	Morgan Energy Center LLC	55293	Morgan Energy Center	IPP CHP	AL	CTG2	CC1	210.0	161.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
29122	Morgan Energy Center LLC	55293	Morgan Energy Center	IPP CHP	AL	CTG3	CC1	210.0	161.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	TVA	16
29122	Morgan Energy Center LLC	55293	Morgan Energy Center	IPP CHP	AL	STG1	CC1	270.0	266.0	266.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	TVA	16
29122	Morgan Energy Center LLC	55293	Morgan Energy Center	IPP CHP	AL	CTG1	CC1	210.0	161.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	1	2004	Operating	TVA	15
2891	Westbrook Energy Center	55294	Westbrook Energy Center Power Plant	IPP Non-CHP	ME	GTG1	CC1	184.2	160.5	181.5	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	ISNE	18
2891	Westbrook Energy Center	55294	Westbrook Energy Center Power Plant	IPP Non-CHP	ME	GTG2	CC1	184.2	160.5	181.5	Natural Gas Fired Combined Cycle	NG	CT	5	2001	Operating	ISNE	18
2891	Westbrook Energy Center	55294	Westbrook Energy Center Power Plant	IPP Non-CHP	ME	STG3	CC1	195.5	185.0	190.5	Natural Gas Fired Combined Cycle	NG	CA	5	2001	Operating	ISNE	18

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
58453	AltaGas Blythe Operations Inc	55295	Blythe Energy Inc	IPP Non-CHP	CA	CT1	CC1	182.0	156.5	160.5	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	CISO	16
58453	AltaGas Blythe Operations Inc	55295	Blythe Energy Inc	IPP Non-CHP	CA	CT2	CC1	182.0	156.5	160.5	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	CISO	16
58453	AltaGas Blythe Operations Inc	55295	Blythe Energy Inc	IPP Non-CHP	CA	ST1	CC1	227.0	201.0	204.0	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	CISO	16
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	1	CTG1	245.0	220.5	228.7	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	PJM	15
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	1A	CTG1	147.0	134.0	136.0	Natural Gas Fired Combined Cycle	NG	CA	3	2004	Operating	PJM	15
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	2	CTG2	245.0	218.2	243.2	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	PJM	15
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	2A	CTG2	147.0	134.0	136.0	Natural Gas Fired Combined Cycle	NG	CA	3	2004	Operating	PJM	15
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	3	CTG3	245.0	214.8	217.3	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	PJM	15
21579	New Covert Generating Company LLC	55297	New Covert Generating Facility	IPP Non-CHP	MI	3A	CTG3	147.0	134.0	136.0	Natural Gas Fired Combined Cycle	NG	CA	3	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	CT1A	BLK1	198.9	189.0	198.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	CT1B	BLK1	198.9	189.0	198.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	CT2A	BLK2	198.9	189.0	198.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	CT2B	BLK2	198.9	189.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	ST1	BLK1	271.2	258.0	263.7	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	PJM	15
54817	Fairless Energy LLC	55298	Fairless Energy Center	IPP Non-CHP	PA	ST2	BLK2	271.2	258.0	263.7	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	PJM	15
3370	Channel Energy Center LLC	55299	Channel Energy Center LLC	IPP CHP	TX	CTG1	CC1	215.0	185.0	210.0	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	ERCO	18
3370	Channel Energy Center LLC	55299	Channel Energy Center LLC	IPP CHP	TX	CTG2	CC1	215.0	185.0	210.0	Natural Gas Fired Combined Cycle	NG	CT	4	2002	Operating	ERCO	17
3370	Channel Energy Center LLC	55299	Channel Energy Center LLC	IPP CHP	TX	ST-1	CC1	285.0	215.0	215.0	Natural Gas Fired Combined Cycle	NG	CA	4	2002	Operating	ERCO	17
3370	Channel Energy Center LLC	55299	Channel Energy Center LLC	IPP CHP	TX	CTG3	CC1	208.8	183.0	189.0	Natural Gas Fired Combined Cycle	NG	CT	6	2014	Operating	ERCO	5
16572	Salt River Project	55306	Gila River Power Block 4	Electric Utility	AZ	CTG7	BL04	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	GRMA	16
16572	Salt River Project	55306	Gila River Power Block 4	Electric Utility	AZ	CTG8	BL04	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	GRMA	16
16572	Salt River Project	55306	Gila River Power Block 4	Electric Utility	AZ	ST12	BL04	271.0	223.0	227.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	GRMA	16
26469	Ingleside Cogeneration LP	55313	Ingleside Cogeneration	Industrial CHP	TX	CTG1	CC1	170.1	155.0	179.0	Natural Gas Fired Combined Cycle	NG	CT	7	1999	Operating	ERCO	20
26469	Ingleside Cogeneration LP	55313	Ingleside Cogeneration	Industrial CHP	TX	CTG2	CC1	170.1	155.0	179.0	Natural Gas Fired Combined Cycle	NG	CT	7	1999	Operating	ERCO	20
26469	Ingleside Cogeneration LP	55313	Ingleside Cogeneration	Industrial CHP	TX	STG	CC1	176.8	150.0	150.0	Natural Gas Fired Combined Cycle	NG	CA	7	1999	Operating	ERCO	20
59368	Calpine Fore River Energy Center, LLC	55317	Fore River Generating Station	IPP Non-CHP	MA	GT11	G942	278.6	228.8	265.7	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	ISNE	16
59368	Calpine Fore River Energy Center, LLC	55317	Fore River Generating Station	IPP Non-CHP	MA	GT12	G942	278.6	228.1	264.9	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	ISNE	16
59368	Calpine Fore River Energy Center, LLC	55317	Fore River Generating Station	IPP Non-CHP	MA	ST15	G942	315.0	269.1	312.4	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	ISNE	16
21668	Wise County Power Company LLC	55320	Wise County Power LLC	IPP Non-CHP	TX	GT1	CC1	242.0	225.0	242.0	Natural Gas Fired Combined Cycle	NG	CT	7	2004	Operating	ERCO	15
21668	Wise County Power Company LLC	55320	Wise County Power LLC	IPP Non-CHP	TX	GT2	CC1	242.0	225.0	242.0	Natural Gas Fired Combined Cycle	NG	CT	7	2004	Operating	ERCO	15
21668	Wise County Power Company LLC	55320	Wise County Power LLC	IPP Non-CHP	TX	ST1	CC1	262.0	230.0	250.0	Natural Gas Fired Combined Cycle	NG	CA	7	2004	Operating	ERCO	15
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	CTG1	PB1	201.5	165.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	1	2006	Operating	NEVP	13
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	CTG2	PB1	201.5	165.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	1	2006	Operating	NEVP	13
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	CTG3	PB2	201.5	165.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	NEVP	13
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	CTG4	PB2	201.5	165.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	NEVP	13
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	ST1	PB1	329.8	255.0	265.0	Natural Gas Fired Combined Cycle	NG	CA	1	2006	Operating	NEVP	13
13407	Nevada Power Co	55322	Chuck Lenzie Generating Station	Electric Utility	NV	ST2	PB2	329.8	255.0	265.0	Natural Gas Fired Combined Cycle	NG	CA	4	2006	Operating	NEVP	13
2838	Baytown Energy Center LLC	55327	Baytown Energy Center	IPP CHP	TX	CTG1	CC1	219.3	165.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
2838	Baytown Energy Center LLC	55327	Baytown Energy Center	IPP CHP	TX	CTG2	CC1	219.3	165.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
2838	Baytown Energy Center LLC	55327	Baytown Energy Center	IPP CHP	TX	CTG3	CC1	219.3	165.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	ERCO	17
2838	Baytown Energy Center LLC	55327	Baytown Energy Center	IPP CHP	TX	STG1	CC1	275.0	275.0	275.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	ERCO	17
7869	Hermiston Power Partnership	55328	Hermiston Power Partnership	IPP Non-CHP	OR	CTG1	CC1	212.5	184.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	CSTO	17
7869	Hermiston Power Partnership	55328	Hermiston Power Partnership	IPP Non-CHP	OR	CTG2	CC1	212.5	184.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	CSTO	17
7869	Hermiston Power Partnership	55328	Hermiston Power Partnership	IPP Non-CHP	OR	STG1	CC1	264.4	247.0	258.0	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	CSTO	17
5030	Delta Energy Center LLC	55333	Delta Energy Center	IPP Non-CHP	CA	CTG1	CC1	212.0	176.0	191.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	CISO	17
5030	Delta Energy Center LLC	55333	Delta Energy Center	IPP Non-CHP	CA	CTG2	CC1	212.0	165.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	CISO	17
5030	Delta Energy Center LLC	55333	Delta Energy Center	IPP Non-CHP	CA	CTG3	CC1	213.5	165.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	CISO	17
5030	Delta Energy Center LLC	55333	Delta Energy Center	IPP Non-CHP	CA	STG1	CC1	306.0	263.1	287.6	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	CISO	17
49974	NAES Corporation - (WA)	55334	Holland Energy Facility	Electric Utility	IL	CTG1	CC1	178.5	151.7	177.9	Natural Gas Fired Combined Cycle	NG	CT	9	2002	Operating	MISO	17
49974	NAES Corporation - (WA)	55334	Holland Energy Facility	Electric Utility	IL	CTG2	CC1	178.5	146.2	179.6	Natural Gas Fired Combined Cycle	NG	CT	9	2002	Operating	MISO	17

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
49974	NAES Corporation - (WA)	55334	Holland Energy Facility	Electric Utility	IL	STG1	CC1	345.1	326.4	330.0	Natural Gas Fired Combined Cycle	NG	CA	9	2002	Operating	MISO	17
61121	Helix, Ironwood LLC	55337	Ironwood LLC	IPP Non-CHP	PA	CT1	CC02	259.2	238.7	272.7	Natural Gas Fired Combined Cycle	NG	CT	12	2001	Operating	PJM	18
61121	Helix, Ironwood LLC	55337	Ironwood LLC	IPP Non-CHP	PA	CT2	CC02	259.2	241.7	272.0	Natural Gas Fired Combined Cycle	NG	CT	12	2001	Operating	PJM	18
61121	Helix, Ironwood LLC	55337	Ironwood LLC	IPP Non-CHP	PA	ST4	CC02	259.2	219.7	230.7	Natural Gas Fired Combined Cycle	NG	CA	12	2001	Operating	PJM	18
924	Associated Electric Coop, Inc	55340	Dell Power Station	Electric Utility	AR	CTG1	CC2	199.3	143.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	8	2007	Operating	AECI	12
924	Associated Electric Coop, Inc	55340	Dell Power Station	Electric Utility	AR	CTG2	CC2	199.3	142.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	8	2007	Operating	AECI	12
924	Associated Electric Coop, Inc	55340	Dell Power Station	Electric Utility	AR	STG	CC2	280.5	144.0	140.0	Natural Gas Fired Combined Cycle	NG	CA	8	2007	Operating	AECI	12
15473	Public Service Co of NM	55343	Luna Energy Facility	Electric Utility	NM	CTG1	CC1	175.0	150.5	164.5	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PNM	13
15473	Public Service Co of NM	55343	Luna Energy Facility	Electric Utility	NM	CTG2	CC1	175.0	150.5	164.5	Natural Gas Fired Combined Cycle	NG	CT	4	2006	Operating	PNM	13
15473	Public Service Co of NM	55343	Luna Energy Facility	Electric Utility	NM	STG1	CC1	300.0	258.0	282.0	Natural Gas Fired Combined Cycle	NG	CA	4	2006	Operating	PNM	13
14274	Otay Mesa Energy Center LLC	55345	Otay Mesa Generating Project	IPP Non-CHP	CA	1-01	CC1	198.9	152.8	165.9	Natural Gas Fired Combined Cycle	NG	CT	10	2009	Operating	CISO	10
14274	Otay Mesa Energy Center LLC	55345	Otay Mesa Generating Project	IPP Non-CHP	CA	1-02	CC1	198.9	152.8	165.9	Natural Gas Fired Combined Cycle	NG	CT	10	2009	Operating	CISO	10
14274	Otay Mesa Energy Center LLC	55345	Otay Mesa Generating Project	IPP Non-CHP	CA	1-03	CC1	290.7	265.4	275.3	Natural Gas Fired Combined Cycle	NG	CA	10	2009	Operating	CISO	10
733	Appalachian Power Co	55350	Dresden Energy Facility	Electric Utility	OH	1	CC1	198.9	158.3	183.3	Natural Gas Fired Combined Cycle	NG	CT	2	2012	Operating	PJM	7
733	Appalachian Power Co	55350	Dresden Energy Facility	Electric Utility	OH	2	CC1	198.9	158.3	183.3	Natural Gas Fired Combined Cycle	NG	CT	2	2012	Operating	PJM	7
733	Appalachian Power Co	55350	Dresden Energy Facility	Electric Utility	OH	3	CC1	280.5	223.4	258.4	Natural Gas Fired Combined Cycle	NG	CA	2	2012	Operating	PJM	7
2171	Brazos Valley Energy	55357	Jack Fusco Energy Center	IPP Non-CHP	TX	CTG1	STG1	200.0	166.0	182.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
2171	Brazos Valley Energy	55357	Jack Fusco Energy Center	IPP Non-CHP	TX	CTG2	STG1	200.0	166.0	182.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
2171	Brazos Valley Energy	55357	Jack Fusco Energy Center	IPP Non-CHP	TX	STG1	STG1	275.6	193.0	230.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	CT1	ST1	198.9	163.7	169.3	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	CT2	ST2	198.9	163.7	169.3	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	CT3	ST3	198.9	163.7	169.3	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	CT4	ST4	198.9	163.7	169.3	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	ST1	ST1	159.5	131.3	135.7	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	ST2	ST2	159.5	131.3	135.7	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	ST3	ST3	159.5	131.3	135.7	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	MISO	16
4405	Cottonwood Energy Co LP	55358	Cottonwood Energy Project	IPP Non-CHP	TX	ST4	ST4	159.5	131.3	135.7	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	MISO	16
13756	Northern Indiana Pub Serv Co	55364	Sugar Creek Power	Electric Utility	IN	CT01	CC1	203.2	164.4	171.3	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
13756	Northern Indiana Pub Serv Co	55364	Sugar Creek Power	Electric Utility	IN	CT02	CC1	203.2	166.6	173.1	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
13756	Northern Indiana Pub Serv Co	55364	Sugar Creek Power	Electric Utility	IN	ST1	CC1	213.0	218.0	218.6	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	MISO	16
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	CTG1	BLK1	281.7	239.9	244.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	HGMA	15
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	CTG2	BLK2	281.7	226.6	247.8	Natural Gas Fired Combined Cycle	NG	CT	9	2004	Operating	HGMA	15
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	CTG3	BLK3	281.7	226.2	245.2	Natural Gas Fired Combined Cycle	NG	CT	8	2004	Operating	HGMA	15
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	STG1	BLK1	160.0	119.8	121.8	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	HGMA	15
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	STG2	BLK2	160.0	114.9	121.1	Natural Gas Fired Combined Cycle	NG	CA	9	2004	Operating	HGMA	15
32790	New Harquahala Generating Co, LLC	55372	Harquahala Generating Project	IPP Non-CHP	AZ	STG3	BLK3	160.0	115.5	120.4	Natural Gas Fired Combined Cycle	NG	CA	8	2004	Operating	HGMA	15
22979	Astoria Energy LLC	55375	Astoria Energy	IPP Non-CHP	NY	CT1	CC1	170.0	156.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	5	2006	Operating	NYIS	13
22979	Astoria Energy LLC	55375	Astoria Energy	IPP Non-CHP	NY	CT2	CC1	170.0	156.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	5	2006	Operating	NYIS	13
22979	Astoria Energy LLC	55375	Astoria Energy	IPP Non-CHP	NY	ST1	CC1	255.0	228.0	266.0	Natural Gas Fired Combined Cycle	NG	CA	5	2006	Operating	NYIS	13
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG1	BL01	176.0			Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG2	BL01	176.0			Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG3	BL02	176.0			Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG4	BL02	176.0			Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG5	BL03	176.0			Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG6	BL03	176.0			Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG7	BL04	176.0			Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	CTG8	BL04	176.0			Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	STG1	BL01	255.0	495.5	512.9	Natural Gas Fired Combined Cycle	NG	CA	1	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	STG2	BL02	255.0	500.6	519.3	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	MISO	16
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	STG3	BL03	255.0	497.3	519.5	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	MISO	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
814	Entergy Arkansas Inc	55380	Union Power Station	Electric Utility	AR	STG4	BL04	255.0	494.4	516.5	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	MISO	16
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	1GT1	1	147.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	1GT2	1	147.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	1STG	1	302.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	SOCO	17
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	2GT1	2	147.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	2GT2	2	147.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
13994	Oglethorpe Power Corporation	55382	Thomas A Smith Energy Facility	Electric Utility	GA	2STG	2	302.0	210.0	215.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	SOCO	17
4028	Columbia Energy LLC	55386	Columbia Energy Center (SC)	IPP CHP	SC	CT1	CC1	197.0	151.5	180.1	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SCEG	15
4028	Columbia Energy LLC	55386	Columbia Energy Center (SC)	IPP CHP	SC	CT2	CC1	197.0	151.5	180.1	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SCEG	15
4028	Columbia Energy LLC	55386	Columbia Energy Center (SC)	IPP CHP	SC	ST1	CC1	274.5	240.0	273.0	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SCEG	15
2799	Calpine Corp - Metcalf Energy Center	55393	Metcalf Energy Center	IPP Non-CHP	CA	CTG1	CC1	200.0	172.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	CISO	14
2799	Calpine Corp - Metcalf Energy Center	55393	Metcalf Energy Center	IPP Non-CHP	CA	CTG2	CC1	200.0	172.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	CISO	14
2799	Calpine Corp - Metcalf Energy Center	55393	Metcalf Energy Center	IPP Non-CHP	CA	STG1	CC1	235.0	202.1	220.9	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	CISO	14
59922	Dynegy Washington Energy Facility	55397	Washington Energy Facility	IPP Non-CHP	OH	CT1	CC1	198.9	179.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	PJM	17
59922	Dynegy Washington Energy Facility	55397	Washington Energy Facility	IPP Non-CHP	OH	CT2	CC1	198.9	179.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	PJM	17
59922	Dynegy Washington Energy Facility	55397	Washington Energy Facility	IPP Non-CHP	OH	ST1	CC1	317.1	303.0	310.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	PJM	17
34164	Elk Hills Power LLC	55400	Elk Hills Power LLC	IPP CHP	CA	CTG1	G541	199.0	156.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	CISO	16
34164	Elk Hills Power LLC	55400	Elk Hills Power LLC	IPP CHP	CA	CTG2	G541	199.0	156.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	CISO	16
34164	Elk Hills Power LLC	55400	Elk Hills Power LLC	IPP CHP	CA	STG	G541	225.0	213.0	219.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	CISO	16
3131	Carville Energy LLC	55404	Carville Energy LLC	IPP CHP	LA	CTG1	CC1	187.0	170.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
3131	Carville Energy LLC	55404	Carville Energy LLC	IPP CHP	LA	CTG2	CC1	187.0	170.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	MISO	16
3131	Carville Energy LLC	55404	Carville Energy LLC	IPP CHP	LA	STG	CC1	181.0	181.0	181.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	MISO	16
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	CT3	3677	300.0	224.2	266.8	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	NYIS	16
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	CT1	3668	300.0	225.8	272.0	Natural Gas Fired Combined Cycle	NG	CT	4	2004	Operating	NYIS	15
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	CT2	3670	300.0	223.1	275.5	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	NYIS	15
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	ST1	3668	141.0	107.7	129.9	Natural Gas Fired Combined Cycle	NG	CA	1	2004	Operating	NYIS	15
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	ST2	3670	141.0	106.4	131.4	Natural Gas Fired Combined Cycle	NG	CA	1	2004	Operating	NYIS	15
32173	New Athens Generating Company LLC	55405	Athens Generating Plant	IPP Non-CHP	NY	ST3	3677	141.0	106.9	127.3	Natural Gas Fired Combined Cycle	NG	CA	1	2004	Operating	NYIS	15
59423	SEPG Operating Services, LLC Effingham	55406	Effingham County Power Project	IPP Non-CHP	GA	STG	CC01	197.8	176.0	182.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	SOCO	16
59423	SEPG Operating Services, LLC Effingham	55406	Effingham County Power Project	IPP Non-CHP	GA	UNT1	CC01	199.4	169.0	175.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	SOCO	16
59423	SEPG Operating Services, LLC Effingham	55406	Effingham County Power Project	IPP Non-CHP	GA	UNT2	CC01	199.4	164.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	SOCO	16
55987	CER Generation LLC	55411	Hillabee Energy Center	IPP Non-CHP	AL	HEC1	CC1	258.4	234.4	265.0	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	SOCO	9
55987	CER Generation LLC	55411	Hillabee Energy Center	IPP Non-CHP	AL	HEC2	CC1	258.4	234.4	265.0	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	SOCO	9
55987	CER Generation LLC	55411	Hillabee Energy Center	IPP Non-CHP	AL	HECS	CC1	306.0	283.9	293.0	Natural Gas Fired Combined Cycle	NG	CA	6	2010	Operating	SOCO	9
6455	Duke Energy Florida, LLC	55412	Osprey Energy Center Power Plant	Electric Utility	FL	OEC1	COEC	192.1	171.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	TEC	15
6455	Duke Energy Florida, LLC	55412	Osprey Energy Center Power Plant	Electric Utility	FL	OEC2	COEC	192.1	180.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	TEC	15
6455	Duke Energy Florida, LLC	55412	Osprey Energy Center Power Plant	Electric Utility	FL	OECS	COEC	260.0	231.0	240.0	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	TEC	15
814	Entergy Arkansas Inc	55418	Hot Spring Generating Facility	Electric Utility	AR	CT1	PB01	198.9			Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
814	Entergy Arkansas Inc	55418	Hot Spring Generating Facility	Electric Utility	AR	CT2	PB01	198.9			Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
814	Entergy Arkansas Inc	55418	Hot Spring Generating Facility	Electric Utility	AR	ST1	PB01	317.0	605.7	605.7	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	MISO	17
5347	Dow Chemical Co	55419	Plaquemine Cogeneration Plant	Industrial CHP	LA	G500	CC2	198.0	151.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	MISO	15
5347	Dow Chemical Co	55419	Plaquemine Cogeneration Plant	Industrial CHP	LA	G600	CC2	198.0	151.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	MISO	15
5347	Dow Chemical Co	55419	Plaquemine Cogeneration Plant	Industrial CHP	LA	G700	CC2	198.0	151.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	MISO	15
5347	Dow Chemical Co	55419	Plaquemine Cogeneration Plant	Industrial CHP	LA	G800	CC2	198.0	151.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	MISO	15
5347	Dow Chemical Co	55419	Plaquemine Cogeneration Plant	Industrial CHP	LA	ST5	CC2	195.0	189.0	189.0	Natural Gas Fired Combined Cycle	NG	CA	3	2004	Operating	MISO	15
18569	Tenaska Virginia Partners LP	55439	Tenaska Virginia Generating Station	IPP Non-CHP	VA	CTG1	STG1	183.3	174.9	207.2	Natural Gas Fired Combined Cycle	NG	CT	4	2004	Operating	PJM	15
18569	Tenaska Virginia Partners LP	55439	Tenaska Virginia Generating Station	IPP Non-CHP	VA	CTG2	STG1	183.3	181.2	208.5	Natural Gas Fired Combined Cycle	NG	CT	4	2004	Operating	PJM	15
18569	Tenaska Virginia Partners LP	55439	Tenaska Virginia Generating Station	IPP Non-CHP	VA	CTG3	STG1	183.3	184.5	204.8	Natural Gas Fired Combined Cycle	NG	CT	4	2004	Operating	PJM	15
18569	Tenaska Virginia Partners LP	55439	Tenaska Virginia Generating Station	IPP Non-CHP	VA	STG1	STG1	396.2	402.9	388.9	Natural Gas Fired Combined Cycle	NG	CA	4	2004	Operating	PJM	15
18835	Tenaska Alabama B LP	55440	Stn	IPP Non-CHP	AL	CTG1	STG1	179.0	171.0	190.1	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	SOCO	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
18835	Tenaska Alabama B LP	55440	Stn	IPP Non-CHP	AL	CTG2	STG1	179.0	175.8	189.1	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	SOCO	16
18835	Tenaska Alabama B LP	55440	Stn	IPP Non-CHP	AL	CTG3	STG1	179.0	173.2	189.7	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	SOCO	16
18835	Tenaska Alabama B LP	55440	Stn	IPP Non-CHP	AL	ST1	STG1	390.1	399.2	401.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	SOCO	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	CTG1	MCC1	178.5	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	CTG2	MCC2	178.5	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	CTG3	MCC3	178.5	156.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	STG1	MCC1	156.0	150.0	150.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	STG2	MCC2	156.0	150.0	150.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	TVA	16
18642	Tennessee Valley Authority	55451	Magnolia Power Plant	Electric Utility	MS	STG3	MCC3	156.0	150.0	150.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	TVA	16
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	CT1A	CC1	187.5	148.0	166.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SRP	17
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	CT1B	CC1	181.6	148.0	166.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SRP	17
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	CT2A	CC2	181.6	148.0	166.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SRP	17
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	CT2B	CC2	181.6	148.0	161.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	SRP	17
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	ST1	CC1	204.0	171.0	174.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	SRP	17
803	Arizona Public Service Co	55455	Red Hawk	Electric Utility	AZ	ST2	CC2	204.0	171.0	174.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	SRP	17
14063	Oklahoma Gas & Electric Co	55457	McClain Energy Facility	Electric Utility	OK	CT1	G011	176.6	161.4	161.4	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	SWPP	18
14063	Oklahoma Gas & Electric Co	55457	McClain Energy Facility	Electric Utility	OK	CT2	G011	176.6	158.5	158.5	Natural Gas Fired Combined Cycle	NG	CT	6	2001	Operating	SWPP	18
14063	Oklahoma Gas & Electric Co	55457	McClain Energy Facility	Electric Utility	OK	ST1	G011	198.1	173.1	173.1	Natural Gas Fired Combined Cycle	NG	CA	6	2001	Operating	SWPP	18
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	CT01	G112	198.9			Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	CT02	G113	198.9			Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	CT03	G114	198.9			Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	CT04	G115	198.9			Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	ST01	G112	159.5	300.6	300.6	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	ST02	G113	159.5	301.1	301.1	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	ST03	G114	159.5	301.1	301.1	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SWPP	15
14063	Oklahoma Gas & Electric Co	55463	Redbud Power Plant	Electric Utility	OK	ST04	G115	159.5	300.2	300.2	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SWPP	15
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	CTG1	CC1	180.0	169.8	184.2	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	ERCO	16
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	CTG2	CC1	180.0	169.8	184.2	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	ERCO	16
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	CTG3	CC1	180.0	169.8	184.2	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	ERCO	15
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	CTG4	CC1	180.0	169.8	184.2	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	ERCO	15
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	STG1	CC1	276.0	282.0	282.0	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	ERCO	15
4994	Deer Park Energy Center	55464	Deer Park Energy Center	IPP CHP	TX	CTG6	CC1	180.0	154.8	169.2	Natural Gas Fired Combined Cycle	NG	CT	6	2014	Operating	ERCO	5
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	CTG1	PB01	179.3			Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	CTG2	PB02	179.3			Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	CTG3	PB03	179.3			Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	STG1	PB01	122.0	251.9	272.1	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	STG2	PB02	122.0	252.7	272.6	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55467	Ouachita	Electric Utility	LA	STG3	PB03	122.0	249.1	268.4	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	MISO	17
17566	South Houston Green Power LLC	55470	Green Power 2	Industrial CHP	TX	ST1	CC2	110.0	75.0	75.0	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	ERCO	16
17566	South Houston Green Power LLC	55470	Green Power 2	Industrial CHP	TX	TR1	CC2	167.0	158.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	ERCO	16
17566	South Houston Green Power LLC	55470	Green Power 2	Industrial CHP	TX	TR2	CC2	167.0	158.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	ERCO	16
17566	South Houston Green Power LLC	55470	Green Power 2	Industrial CHP	TX	TR3	CC2	167.0	158.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	ERCO	16
17566	South Houston Green Power LLC	55470	Green Power 2	Industrial CHP	TX	ST805	CC2	250.0	75.0	75.0	Natural Gas Fired Combined Cycle	NG	CA	5	2009	Operating	ERCO	10
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	ST1	BLK1	382.5	415.0	420.0	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	ST2	BLK2	382.5	415.0	420.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U1	BLK1	188.2	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U2	BLK1	188.2	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U3	BLK1	188.2	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U4	BLK2	188.2	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	ERCO	16
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U5	BLK2	188.2	169.0	192.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	ERCO	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
60477	LaFrontera Holdings LLC	55480	Forney Energy Center	IPP Non-CHP	TX	U6	BLK2	188.2	168.0	191.0	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	ERCO	16
59532	CAMS	55481	Mesquite Generating Station Block 2	IPP Non-CHP	AZ	GT3	BLK2	185.3	153.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	SRP	16
59532	CAMS	55481	Mesquite Generating Station Block 2	IPP Non-CHP	AZ	GT4	BLK2	185.3	153.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	12	2003	Operating	SRP	16
59532	CAMS	55481	Mesquite Generating Station Block 2	IPP Non-CHP	AZ	ST2	BLK2	321.0	289.0	300.0	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	SRP	16
15500	Puget Sound Energy Inc	55482	Goldendale Generating Station	Electric Utility	WA	G1	CC1	170.0	153.1	194.0	Natural Gas Fired Combined Cycle	NG	CT	8	2004	Operating	PSEI	15
15500	Puget Sound Energy Inc	55482	Goldendale Generating Station	Electric Utility	WA	G2	CC1	114.3	110.6	110.6	Natural Gas Fired Combined Cycle	NG	CA	8	2004	Operating	PSEI	15
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	CTG1	STG1	183.9	158.2	172.9	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ERCO	16
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	CTG2	STG1	183.9	158.2	172.9	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ERCO	16
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	CTG3	STG2	183.9	158.2	172.9	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ERCO	16
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	CTG4	STG2	183.9	158.2	172.9	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	ERCO	16
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	STG1	STG1	317.2	272.8	298.2	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	ERCO	16
10362	Kiowa Power Partners LLC	55501	Kiamichi Energy Facility	IPP Non-CHP	OK	STG2	STG2	317.2	272.8	298.2	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	ERCO	16
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	0100	CC1	268.0	258.0	261.0	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	PJM	15
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	0200	CC2	268.0	238.0	261.0	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	PJM	15
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	1100	CC1	174.0	168.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	1200	CC1	174.0	168.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	2100	CC2	174.0	151.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
61137	Lawrenceburg Power, LLC	55502	Lawrenceburg Power, LLC	IPP Non-CHP	IN	2200	CC2	174.0	151.0	199.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
61136	Waterford Power, LLC	55503	Waterford Power, LLC	IPP Non-CHP	OH	CTG1	CC1	174.2	168.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	PJM	16
61136	Waterford Power, LLC	55503	Waterford Power, LLC	IPP Non-CHP	OH	CTG2	CC1	174.2	168.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	PJM	16
61136	Waterford Power, LLC	55503	Waterford Power, LLC	IPP Non-CHP	OH	CTG3	CC1	174.2	168.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	PJM	16
61136	Waterford Power, LLC	55503	Waterford Power, LLC	IPP Non-CHP	OH	ST1	CC1	399.0	362.0	390.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	PJM	16
11208	Los Angeles Department of Water & Power	55514	Apex Generating Station	Electric Utility	NV	CTG1	CC1	174.0	164.6	181.6	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	NEVP	16
11208	Los Angeles Department of Water & Power	55514	Apex Generating Station	Electric Utility	NV	CTG2	CC1	174.0	164.6	181.6	Natural Gas Fired Combined Cycle	NG	CT	5	2003	Operating	NEVP	16
11208	Los Angeles Department of Water & Power	55514	Apex Generating Station	Electric Utility	NV	STG1	CC1	252.6	195.2	213.4	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	NEVP	16
59923	Dynegy Fayette Energy Facility	55516	Fayette Energy Facility	IPP Non-CHP	PA	CTG1	CC1	163.5	174.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	PJM	16
59923	Dynegy Fayette Energy Facility	55516	Fayette Energy Facility	IPP Non-CHP	PA	CTG2	CC1	163.5	174.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	PJM	16
59923	Dynegy Fayette Energy Facility	55516	Fayette Energy Facility	IPP Non-CHP	PA	STG1	CC1	317.1	314.0	315.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	PJM	16
60431	MRP Generation Holdings, LLC	55518	High Desert Power Plant	IPP Non-CHP	CA	CTG1	STG1	173.0	157.6	160.3	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	CISO	16
60431	MRP Generation Holdings, LLC	55518	High Desert Power Plant	IPP Non-CHP	CA	CTG2	STG1	173.0	157.6	159.7	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	CISO	16
60431	MRP Generation Holdings, LLC	55518	High Desert Power Plant	IPP Non-CHP	CA	CTG3	STG1	173.0	156.5	175.8	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	CISO	16
60431	MRP Generation Holdings, LLC	55518	High Desert Power Plant	IPP Non-CHP	CA	STG1	STG1	333.0	304.8	310.6	Natural Gas Fired Combined Cycle	NG	CA	4	2003	Operating	CISO	16
56608	Calpine Mid-Merit LLC	55524	York Energy Center	IPP Non-CHP	PA	CTG1	CCB1	120.0	113.0	113.0	Natural Gas Fired Combined Cycle	NG	CT	3	2011	Operating	PJM	8
56608	Calpine Mid-Merit LLC	55524	York Energy Center	IPP Non-CHP	PA	CTG2	CCB1	120.0	122.0	122.0	Natural Gas Fired Combined Cycle	NG	CT	3	2011	Operating	PJM	8
56608	Calpine Mid-Merit LLC	55524	York Energy Center	IPP Non-CHP	PA	CTG3	CCB1	120.0	122.0	122.0	Natural Gas Fired Combined Cycle	NG	CT	3	2011	Operating	PJM	8
2934	Calpine Corp - Hidalgo	55545	Hidalgo Energy Center	IPP Non-CHP	TX	CTG1	CC1	176.6	149.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
2934	Calpine Corp - Hidalgo	55545	Hidalgo Energy Center	IPP Non-CHP	TX	CTG2	CC1	176.6	149.0	168.0	Natural Gas Fired Combined Cycle	NG	CT	6	2000	Operating	ERCO	19
2934	Calpine Corp - Hidalgo	55545	Hidalgo Energy Center	IPP Non-CHP	TX	STG1	CC1	198.1	172.0	182.0	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	ERCO	19
744	Appleton Coated LLC	55558	Combined Locks Energy Center	Industrial CHP	WI	GEN1	CC1	60.5	45.9	47.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	MISO	17
744	Appleton Coated LLC	55558	Combined Locks Energy Center	Industrial CHP	WI	GEN2	CC1	6.0	6.0	6.0	Natural Gas Fired Combined Cycle	NG	CA	5	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55620	Perryville Power Station	Electric Utility	LA	CT-1	PB01	198.9			Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55620	Perryville Power Station	Electric Utility	LA	CT-2	PB01	198.9			Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	MISO	17
11241	Entergy Louisiana LLC	55620	Perryville Power Station	Electric Utility	LA	ST-1	PB01	240.1	534.2	576.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	MISO	17
20856	Wisconsin Power & Light Co	55641	Riverside Energy Center	Electric Utility	WI	CTG1	S112	198.9	153.9	169.7	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	MISO	15
20856	Wisconsin Power & Light Co	55641	Riverside Energy Center	Electric Utility	WI	CTG2	S112	198.9	155.0	169.3	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	MISO	15
20856	Wisconsin Power & Light Co	55641	Riverside Energy Center	Electric Utility	WI	STG1	S112	277.1	249.0	269.2	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	MISO	15
2820	Calpine Corp - Pastoria Energy Center	55656	Pastoria Energy Facility, LLC	IPP Non-CHP	CA	CT01	PB01	168.0	175.0	185.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	CISO	14
2820	Calpine Corp - Pastoria Energy Center	55656	Pastoria Energy Facility, LLC	IPP Non-CHP	CA	CT02	PB01	168.0	173.0	183.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	CISO	14
2820	Calpine Corp - Pastoria Energy Center	55656	Pastoria Energy Facility, LLC	IPP Non-CHP	CA	CT04	PB02	168.0	156.0	161.0	Natural Gas Fired Combined Cycle	NG	CT	5	2005	Operating	CISO	14
2820	Calpine Corp - Pastoria Energy Center	55656	Pastoria Energy Facility, LLC	IPP Non-CHP	CA	ST03	PB01	185.0	174.0	184.0	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	CISO	14

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
2820	Calpine Corp - Pastoria Energy Center	55656	Pastoria Energy Facility, LLC	IPP Non-CHP	CA	ST05	PB02	90.0	87.0	89.0	Natural Gas Fired Combined Cycle	NG	CA	5	2005	Operating	CISO	14
13538	Essential Power Newington LLC	55661	Essential Power Newington LLC	IPP Non-CHP	NH	GT-1	CC1	185.6	161.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ISNE	17
13538	Essential Power Newington LLC	55661	Essential Power Newington LLC	IPP Non-CHP	NH	GT-2	CC1	185.6	161.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	10	2002	Operating	ISNE	17
13538	Essential Power Newington LLC	55661	Essential Power Newington LLC	IPP Non-CHP	NH	ST	CC1	234.3	231.0	233.0	Natural Gas Fired Combined Cycle	NG	CA	10	2002	Operating	ISNE	17
14354	PacifiCorp	55662	Chehalis Generating Facility	Electric Utility	WA	CA	CC1	230.0	157.0	167.0	Natural Gas Fired Combined Cycle	NG	CA	8	2003	Operating	BPAT	16
14354	PacifiCorp	55662	Chehalis Generating Facility	Electric Utility	WA	CT1	CC1	234.0	160.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	BPAT	16
14354	PacifiCorp	55662	Chehalis Generating Facility	Electric Utility	WA	CT2	CC1	234.0	160.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	8	2003	Operating	BPAT	16
39347	East Texas Electric Coop, Inc	55664	Harrison County Power Project	Electric Utility	TX	GT-1	CC1	170.0	144.5	166.6	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SWPP	16
39347	East Texas Electric Coop, Inc	55664	Harrison County Power Project	Electric Utility	TX	GT-2	CC1	170.0	144.5	166.6	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SWPP	16
39347	East Texas Electric Coop, Inc	55664	Harrison County Power Project	Electric Utility	TX	ST-1	CC1	230.0	225.4	225.4	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SWPP	16
11275	Lower Mount Bethel Energy LLC	55667	Lower Mount Bethel Energy	IPP Non-CHP	PA	G1	CC01	211.5	160.9	198.1	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	PJM	15
11275	Lower Mount Bethel Energy LLC	55667	Lower Mount Bethel Energy	IPP Non-CHP	PA	G2	CC01	211.5	162.6	196.9	Natural Gas Fired Combined Cycle	NG	CT	3	2004	Operating	PJM	15
11275	Lower Mount Bethel Energy LLC	55667	Lower Mount Bethel Energy	IPP Non-CHP	PA	G3	CC01	228.6	214.0	232.5	Natural Gas Fired Combined Cycle	NG	CA	2	2004	Operating	PJM	15
13407	Nevada Power Co	55687	Higgins Generating Station	Electric Utility	NV	A01	PB1	178.0	157.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	2	2004	Operating	NEVP	15
13407	Nevada Power Co	55687	Higgins Generating Station	Electric Utility	NV	A02	PB1	178.0	157.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	2	2004	Operating	NEVP	15
13407	Nevada Power Co	55687	Higgins Generating Station	Electric Utility	NV	ST1	PB1	332.4	236.0	260.0	Natural Gas Fired Combined Cycle	NG	CA	2	2004	Operating	NEVP	15
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG1	1234	127.0	118.0	118.0	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	PJM	17
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG2	1234	127.0	127.0	127.0	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	PJM	17
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG3	1234	127.0	127.0	127.0	Natural Gas Fired Combined Cycle	NG	CT	12	2002	Operating	PJM	17
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG5	5678	127.0	118.0	118.0	Natural Gas Fired Combined Cycle	NG	CT	1	2003	Operating	PJM	16
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG6	5678	127.0	127.0	127.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	PJM	16
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	CTG7	5678	127.0	127.0	127.0	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	PJM	16
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	STG4	1234	195.5	195.0	195.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	PJM	16
56607	Calpine Bethlehem LLC	55690	Bethlehem Power Plant	IPP Non-CHP	PA	STG8	5678	195.5	195.0	195.0	Natural Gas Fired Combined Cycle	NG	CA	12	2003	Operating	PJM	16
18642	Tennessee Valley Authority	55694	Quantum Choctaw Power LLC	Electric Utility	MS	CT1	CC1	270.0	220.0	240.0	Natural Gas Fired Combined Cycle	NG	CT	6	2006	Operating	TVA	13
18642	Tennessee Valley Authority	55694	Quantum Choctaw Power LLC	Electric Utility	MS	CT2	CC1	270.0	220.0	240.0	Natural Gas Fired Combined Cycle	NG	CT	11	2006	Operating	TVA	13
18642	Tennessee Valley Authority	55694	Quantum Choctaw Power LLC	Electric Utility	MS	ST1	CC1	310.5	270.0	285.0	Natural Gas Fired Combined Cycle	NG	CA	7	2006	Operating	TVA	13
15500	Puget Sound Energy Inc	55700	Mint Farm Generating Station	Electric Utility	WA	1STG	CC1	133.0	111.0	129.0	Natural Gas Fired Combined Cycle	NG	CA	1	2008	Operating	PSEI	11
15500	Puget Sound Energy Inc	55700	Mint Farm Generating Station	Electric Utility	WA	CTG1	CC1	186.0	177.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	1	2008	Operating	PSEI	11
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	Electric Utility	OH	CA01	CC1	358.7	346.6	357.8	Natural Gas Fired Combined Cycle	NG	CA	1	2012	Operating	PJM	7
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	Electric Utility	OH	CT01	CC1	190.4	164.8	183.7	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	PJM	7
40577	American Mun Power-Ohio, Inc	55701	Fremont Energy Center	Electric Utility	OH	CT02	CC1	190.4	160.5	182.6	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	PJM	7
54885	NRG Wholesale Generation LP	55706	Choctaw County	IPP Non-CHP	MS	CTG1	CC1	179.0	164.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	TVA	16
54885	NRG Wholesale Generation LP	55706	Choctaw County	IPP Non-CHP	MS	CTG2	CC1	179.0	164.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	TVA	16
54885	NRG Wholesale Generation LP	55706	Choctaw County	IPP Non-CHP	MS	CTG3	CC1	179.0	164.0	186.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	TVA	16
54885	NRG Wholesale Generation LP	55706	Choctaw County	IPP Non-CHP	MS	STG1	CC1	362.0	289.0	326.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	TVA	16
61267	Springdale Energy LLC	55710	Allegheny Energy Units 3 4 & 5	IPP Non-CHP	PA	UNT3	CC1	184.0	167.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
61267	Springdale Energy LLC	55710	Allegheny Energy Units 3 4 & 5	IPP Non-CHP	PA	UNT4	CC1	184.0	167.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
61267	Springdale Energy LLC	55710	Allegheny Energy Units 3 4 & 5	IPP Non-CHP	PA	UNT5	CC1	188.0	175.0	182.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	PJM	16
807	Arkansas Electric Coop Corp	55714	Magnet Cove	Electric Utility	AR	GT1	MC1	242.0	208.1	227.5	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	MISO	14
807	Arkansas Electric Coop Corp	55714	Magnet Cove	Electric Utility	AR	ST1	MC1	262.0	225.3	246.3	Natural Gas Fired Combined Cycle	NG	CA	7	2005	Operating	MISO	14
807	Arkansas Electric Coop Corp	55714	Magnet Cove	Electric Utility	AR	GT2	MC1	242.0	208.1	227.5	Natural Gas Fired Combined Cycle	NG	CT	1	2006	Operating	MISO	13
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	1GT1	CC1	198.9	181.0	200.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	PJM	16
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	1GT2	CC1	198.9	183.0	201.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	PJM	16
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	1ST	CC1	317.1	316.0	311.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	PJM	16
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	2GT1	CC2	198.9	185.0	201.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	2GT2	CC2	198.9	186.0	201.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
59924	Dynegy Hanging Rock Energy Facility	55736	Hanging Rock Energy Facility	IPP Non-CHP	OH	2ST	CC2	317.1	314.0	312.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	PJM	16
2860	Los Esteros Critical Energy Facility LLC	55748	Los Esteros Critical Energy Center	IPP Non-CHP	CA	CTG1	CC1	45.0	45.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	CISO	16
2860	Los Esteros Critical Energy Facility LLC	55748	Los Esteros Critical Energy Center	IPP Non-CHP	CA	CTG2	CC1	45.0	45.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	CISO	16

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
2860	Los Esteros Critical Energy Facility LLC	55748	Los Esteros Critical Energy Center	IPP Non-CHP	CA	CTG3	CC1	45.0	45.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	CISO	16
2860	Los Esteros Critical Energy Facility LLC	55748	Los Esteros Critical Energy Center	IPP Non-CHP	CA	CTG4	CC1	45.0	45.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	2	2003	Operating	CISO	16
2860	Los Esteros Critical Energy Facility LLC	55748	Los Esteros Critical Energy Center	IPP Non-CHP	CA	CAG5	CC1	126.1	126.1	126.1	Natural Gas Fired Combined Cycle	NG	CA	8	2013	Operating	CISO	6
6693	Marcus Hook Energy LP	55801	Marcus Hook Energy LP	IPP CHP	PA	CT13	CCG1	188.2	172.0	193.0	Natural Gas Fired Combined Cycle	NG	CT	12	2004	Operating	PJM	15
6693	Marcus Hook Energy LP	55801	Marcus Hook Energy LP	IPP CHP	PA	CT1A	CCG1	188.2	178.7	193.0	Natural Gas Fired Combined Cycle	NG	CT	12	2004	Operating	PJM	15
6693	Marcus Hook Energy LP	55801	Marcus Hook Energy LP	IPP CHP	PA	CTIB	CCG1	188.2	172.0	193.0	Natural Gas Fired Combined Cycle	NG	CT	12	2004	Operating	PJM	15
6693	Marcus Hook Energy LP	55801	Marcus Hook Energy LP	IPP CHP	PA	STG	CCG1	271.5	263.0	268.0	Natural Gas Fired Combined Cycle	NG	CA	12	2004	Operating	PJM	15
56613	Frederickson Power LP	55818	Frederickson Power LP	IPP Non-CHP	WA	FICT	FP1	192.0	164.0	180.0	Natural Gas Fired Combined Cycle	NG	CT	8	2002	Operating	BPAT	17
56613	Frederickson Power LP	55818	Frederickson Power LP	IPP Non-CHP	WA	FIST	FP1	126.3	82.0	85.0	Natural Gas Fired Combined Cycle	NG	CA	8	2002	Operating	BPAT	17
17650	Southern Power Co	55821	Curtis H Stanton Energy Center	IPP Non-CHP	FL	A	G105	203.2	188.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	FPC	16
17650	Southern Power Co	55821	Curtis H Stanton Energy Center	IPP Non-CHP	FL	B	G105	203.2	188.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	10	2003	Operating	FPC	16
17650	Southern Power Co	55821	Curtis H Stanton Energy Center	IPP Non-CHP	FL	C	G105	281.9	281.0	281.0	Natural Gas Fired Combined Cycle	NG	CA	10	2003	Operating	FPC	16
15466	Public Service Co of Colorado	55835	Rocky Mountain Energy Center	Electric Utility	CO	CTG1	RKM0	175.1	145.0	157.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	PSCO	15
15466	Public Service Co of Colorado	55835	Rocky Mountain Energy Center	Electric Utility	CO	CTG2	RKM0	175.1	145.0	157.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	PSCO	15
15466	Public Service Co of Colorado	55835	Rocky Mountain Energy Center	Electric Utility	CO	STG1	RKM0	334.9	290.0	301.0	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	PSCO	15
13407	Nevada Power Co	55841	Silverhawk	Electric Utility	NV	CT1	PB1	197.2	157.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	NEVP	15
13407	Nevada Power Co	55841	Silverhawk	Electric Utility	NV	CT2	PB1	197.2	157.0	170.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	NEVP	15
13407	Nevada Power Co	55841	Silverhawk	Electric Utility	NV	ST1	PB1	270.3	246.0	260.0	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	NEVP	15
9155	Inland Empire Energy Ctr LLC	55853	Inland Empire Energy Center	IPP Non-CHP	CA	1		409.5	345.0	376.0	Natural Gas Fired Combined Cycle	NG	CS	7	2009	Operating	CISO	10
9155	Inland Empire Energy Ctr LLC	55853	Inland Empire Energy Center	IPP Non-CHP	CA	2		409.5	345.0	366.0	Natural Gas Fired Combined Cycle	NG	CS	5	2010	of service	CISO	9
17539	South Carolina Electric&Gas Company	55927	Jasper	Electric Utility	SC	CT1	JASP	198.9	156.0	171.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SCEG	15
17539	South Carolina Electric&Gas Company	55927	Jasper	Electric Utility	SC	CT2	JASP	198.9	164.0	177.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SCEG	15
17539	South Carolina Electric&Gas Company	55927	Jasper	Electric Utility	SC	CT3	JASP	198.9	147.0	174.0	Natural Gas Fired Combined Cycle	NG	CT	5	2004	Operating	SCEG	15
17539	South Carolina Electric&Gas Company	55927	Jasper	Electric Utility	SC	ST1	JASP	405.0	385.0	402.0	Natural Gas Fired Combined Cycle	NG	CA	5	2004	Operating	SCEG	15
7724	AltaGas San Joaquin Energy Inc.	55933	Tracy Combined Cycle Power Plant	IPP Non-CHP	CA	TPP1	CC12	84.4	82.1	87.5	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	CISO	16
7724	AltaGas San Joaquin Energy Inc.	55933	Tracy Combined Cycle Power Plant	IPP Non-CHP	CA	TPP2	CC12	84.4	81.8	87.4	Natural Gas Fired Combined Cycle	NG	CT	4	2003	Operating	CISO	16
7724	AltaGas San Joaquin Energy Inc.	55933	Tracy Combined Cycle Power Plant	IPP Non-CHP	CA	TCC1	CC12	167.3	156.2	167.3	Natural Gas Fired Combined Cycle	NG	CA	7	2012	Operating	CISO	7
19876	Virginia Electric & Power Co	55939	Warren County	Electric Utility	VA	CT01	WC01	297.5	297.5	297.5	Natural Gas Fired Combined Cycle	NG	CT	12	2014	Operating	PJM	5
19876	Virginia Electric & Power Co	55939	Warren County	Electric Utility	VA	CT02	WC01	297.5	297.5	297.5	Natural Gas Fired Combined Cycle	NG	CT	12	2014	Operating	PJM	5
19876	Virginia Electric & Power Co	55939	Warren County	Electric Utility	VA	CT03	WC01	297.5	297.5	297.5	Natural Gas Fired Combined Cycle	NG	CT	12	2014	Operating	PJM	5
19876	Virginia Electric & Power Co	55939	Warren County	Electric Utility	VA	ST01	WC01	579.7	579.7	579.7	Natural Gas Fired Combined Cycle	NG	CA	12	2014	Operating	PJM	5
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	CT6A	G106	203.1	178.5	187.4	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	CT6B	G106	203.1	178.5	187.4	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	CT7A	G107	203.1	183.5	190.5	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	CT7B	G107	203.1	183.5	190.5	Natural Gas Fired Combined Cycle	NG	CT	6	2002	Operating	SOCO	17
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	ST6	G106	213.3	213.0	213.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	SOCO	17
17650	Southern Power Co	55965	Wansley Combined Cycle	IPP Non-CHP	GA	ST7	G107	213.3	213.0	213.0	Natural Gas Fired Combined Cycle	NG	CA	6	2002	Operating	SOCO	17
19558	Homer Electric Assn Inc	55966	Nikiski Co-Generation	Electric Utility	AK	GT1	CC1	40.8	37.9	42.0	Natural Gas Fired Combined Cycle	NG	CT	9	1986	Operating		33
19558	Homer Electric Assn Inc	55966	Nikiski Co-Generation	Electric Utility	AK	ST1	CC1	40.0	40.0	40.0	Natural Gas Fired Combined Cycle	NG	CA	7	2013	Operating		6
16534	Sacramento Municipal Util Dist	55970	Cosumnes	Electric Utility	CA	1	CCC1	190.0	171.0	178.6	Natural Gas Fired Combined Cycle	NG	CA	2	2006	Operating	BANC	13
16534	Sacramento Municipal Util Dist	55970	Cosumnes	Electric Utility	CA	2	CCC1	170.0	166.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	BANC	13
16534	Sacramento Municipal Util Dist	55970	Cosumnes	Electric Utility	CA	3	CCC1	170.0	166.0	178.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	BANC	13
54885	NRG Wholesale Generation LP	55976	Hunterstown Power Plant	IPP Non-CHP	PA	101	CT1	179.0	153.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
54885	NRG Wholesale Generation LP	55976	Hunterstown Power Plant	IPP Non-CHP	PA	201	CT1	179.0	153.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
54885	NRG Wholesale Generation LP	55976	Hunterstown Power Plant	IPP Non-CHP	PA	301	CT1	179.0	153.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	PJM	16
54885	NRG Wholesale Generation LP	55976	Hunterstown Power Plant	IPP Non-CHP	PA	401	CT1	361.0	299.0	315.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	PJM	16
6204	City of Farmington - (NM)	55977	Bluffview	Electric Utility	NM	CTG1	CC1	40.0	31.0	40.0	Natural Gas Fired Combined Cycle	NG	CT	5	2005	Operating	WACM	14
6204	City of Farmington - (NM)	55977	Bluffview	Electric Utility	NM	STG1	CC1	27.0	27.0	27.0	Natural Gas Fired Combined Cycle	NG	CA	5	2005	Operating	WACM	14
16609	San Diego Gas & Electric Co	55985	Palomar Energy	Electric Utility	CA	CTG1	CC1	165.0	170.0	170.5	Natural Gas Fired Combined Cycle	NG	CT	10	2005	Operating	CISO	14
16609	San Diego Gas & Electric Co	55985	Palomar Energy	Electric Utility	CA	CTG2	CC1	165.0	170.0	170.5	Natural Gas Fired Combined Cycle	NG	CT	11	2005	Operating	CISO	14

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
16609	San Diego Gas & Electric Co	55985	Palomar Energy	Electric Utility	CA	STG	CC1	229.0	222.0	229.0	Natural Gas Fired Combined Cycle	NG	CA	1	2006	Operating	CISO	13
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	1	G1	4.9	4.4	5.4	Natural Gas Fired Combined Cycle	NG	CT	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	2	G1	4.9	4.4	5.4	Natural Gas Fired Combined Cycle	NG	CT	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	3	G1	4.9	4.4	5.4	Natural Gas Fired Combined Cycle	NG	CT	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	4	G1	4.9	4.4	5.4	Natural Gas Fired Combined Cycle	NG	CT	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	5	G1	4.9	4.4	5.4	Natural Gas Fired Combined Cycle	NG	CT	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	6	G1	0.8	0.7	0.8	Natural Gas Fired Combined Cycle	NG	CA	2	2001	Operating	PJM	18
58115	DTE Ashtabula, LLC	55990	Ashtabula	IPP CHP	OH	7	G1	0.8	0.7	0.8	Natural Gas Fired Combined Cycle	NG	CA	2	2001	Operating	PJM	18
16655	City of Santa Clara - (CA)	56026	Donald Von Raesfeld Power Plant	Electric Utility	CA	CTG1	DVR1	50.0	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	3	2005	Operating	CISO	14
16655	City of Santa Clara - (CA)	56026	Donald Von Raesfeld Power Plant	Electric Utility	CA	CTG2	DVR1	50.0	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CT	3	2005	Operating	CISO	14
16655	City of Santa Clara - (CA)	56026	Donald Von Raesfeld Power Plant	Electric Utility	CA	STG	DVR1	54.0	47.8	47.8	Natural Gas Fired Combined Cycle	NG	CA	3	2005	Operating	CISO	14
20860	Wisconsin Public Service Corp	56031	Fox Energy Center	Electric Utility	WI	CTG2	CC1	198.9	167.4	200.3	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	MISO	14
20860	Wisconsin Public Service Corp	56031	Fox Energy Center	Electric Utility	WI	STG	CC1	221.0	237.4	238.6	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	MISO	14
20860	Wisconsin Public Service Corp	56031	Fox Energy Center	Electric Utility	WI	CTG1	CC1	198.9	166.3	200.1	Natural Gas Fired Combined Cycle	NG	CT	6	2006	Operating	MISO	13
29116	Colorado Energy Management LLC	56041	Malburg	IPP Non-CHP	CA	M1	MGS	40.0	42.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	10	2005	Operating	CISO	14
29116	Colorado Energy Management LLC	56041	Malburg	IPP Non-CHP	CA	M2	MGS	40.0	42.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	10	2005	Operating	CISO	14
29116	Colorado Energy Management LLC	56041	Malburg	IPP Non-CHP	CA	M3	MGS	50.0	50.0	50.0	Natural Gas Fired Combined Cycle	NG	CA	10	2005	Operating	CISO	14
2507	City of Burbank Water and Power	56046	Magnolia Power Project	Electric Utility	CA	1	CC1	198.9	161.0	165.0	Natural Gas Fired Combined Cycle	NG	CT	9	2005	Operating	LDWP	14
2507	City of Burbank Water and Power	56046	Magnolia Power Project	Electric Utility	CA	2	CC1	188.7	140.0	140.0	Natural Gas Fired Combined Cycle	NG	CA	9	2005	Operating	LDWP	14
19002	CPV Towantic, LLC	56047	CPV Towantic Energy Center	IPP Non-CHP	CT	CTG1	CC1	280.5	233.6	270.7	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	ISNE	1
19002	CPV Towantic, LLC	56047	CPV Towantic Energy Center	IPP Non-CHP	CT	CTG2	CC1	280.5	233.6	270.7	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	ISNE	1
19002	CPV Towantic, LLC	56047	CPV Towantic Energy Center	IPP Non-CHP	CT	STG	CC1	280.5	277.8	280.5	Natural Gas Fired Combined Cycle	NG	CA	5	2018	Operating	ISNE	1
19281	Turlock Irrigation District	56078	Walnut Energy Center	Electric Utility	CA	1	WEC	94.9	84.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	TIDC	13
19281	Turlock Irrigation District	56078	Walnut Energy Center	Electric Utility	CA	2	WEC	94.9	84.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	2	2006	Operating	TIDC	13
19281	Turlock Irrigation District	56078	Walnut Energy Center	Electric Utility	CA	3	WEC	110.8	101.0	101.0	Natural Gas Fired Combined Cycle	NG	CA	2	2006	Operating	TIDC	13
14354	PacifiCorp	56102	Currant Creek	Electric Utility	UT	CT1A	CC1	172.0	135.0	143.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	PACE	14
14354	PacifiCorp	56102	Currant Creek	Electric Utility	UT	CT1B	CC1	172.0	135.0	143.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	PACE	14
14354	PacifiCorp	56102	Currant Creek	Electric Utility	UT	ST1	CC1	305.0	254.0	269.0	Natural Gas Fired Combined Cycle	NG	CA	4	2006	Operating	PACE	13
17650	Southern Power Co	56104	Mankato Energy Center	IPP Non-CHP	MN	CTG2	MKST	210.0	174.0	187.0	Natural Gas Fired Combined Cycle	NG	CT	7	2006	Operating	MISO	13
17650	Southern Power Co	56104	Mankato Energy Center	IPP Non-CHP	MN	STG1	MKST	320.0	156.0	190.0	Natural Gas Fired Combined Cycle	NG	CA	7	2006	Operating	MISO	13
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	10ST	G110	281.9	281.8	281.8	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	SOCO	14
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	11ST	G111	281.9	281.8	281.8	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	SOCO	14
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	C10A	G110	203.2	189.6	196.8	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	SOCO	14
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	C10B	G110	203.2	189.6	196.8	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	SOCO	14
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	C11A	G111	203.2	187.9	197.9	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	SOCO	14
7140	Georgia Power Co	56150	McIntosh Combined Cycle Facility	Electric Utility	GA	C11B	G111	203.2	187.9	198.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	SOCO	14
5338	Dow Chemical Co	56152	Freeport Energy Center	Industrial CHP	TX	CTG1	PLTB	180.0	169.4	188.7	Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	ERCO	12
5338	Dow Chemical Co	56152	Freeport Energy Center	Industrial CHP	TX	STG1	PLTB	80.0	50.0	70.0	Natural Gas Fired Combined Cycle	NG	CA	5	2007	Operating	ERCO	12
12667	Minnesota Municipal Power Agny	56164	Faribault Energy Park	Electric Utility	MN	EU01	G861	212.5	153.0	182.0	Natural Gas Fired Combined Cycle	NG	CT	5	2005	Operating	MISO	14
12667	Minnesota Municipal Power Agny	56164	Faribault Energy Park	Electric Utility	MN	HRSG	G861	122.0	108.0	108.0	Natural Gas Fired Combined Cycle	NG	CA	8	2007	Operating	MISO	12
40575	Utah Associated Mun Power Sys	56177	Nebo Power Station	Electric Utility	UT	GT1	CC1	65.0	65.0	65.0	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PACE	15
40575	Utah Associated Mun Power Sys	56177	Nebo Power Station	Electric Utility	UT	ST1	CC1	75.0	65.0	75.0	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	PACE	15
49837	Pinelawn Power LLC	56188	Pinelawn Power LLC	IPP Non-CHP	NY	CTG	CC1	50.0	47.0	47.0	Natural Gas Fired Combined Cycle	NG	CT	7	2005	Operating	NYIS	14
49837	Pinelawn Power LLC	56188	Pinelawn Power LLC	IPP Non-CHP	NY	STG	CC1	32.0	27.5	30.1	Natural Gas Fired Combined Cycle	NG	CA	10	2005	Operating	NYIS	14
15296	New York Power Authority	56196	500MW CC	Electric Utility	NY	CT01	CC1	170.0	151.3	184.4	Natural Gas Fired Combined Cycle	NG	CT	12	2005	Operating	NYIS	14
15296	New York Power Authority	56196	500MW CC	Electric Utility	NY	CT02	CC1	170.0	151.3	184.4	Natural Gas Fired Combined Cycle	NG	CT	12	2005	Operating	NYIS	14
15248	Portland General Electric Co	56227	Port Westward	Electric Utility	OR	1	CCG1	312.0	256.2	267.9	Natural Gas Fired Combined Cycle	NG	CT	6	2007	Operating	PGE	12
15248	Portland General Electric Co	56227	Port Westward	Electric Utility	OR	2	CCG1	171.0	136.0	138.5	Natural Gas Fired Combined Cycle	NG	CA	6	2007	Operating	PGE	12
49913	University of Arizona	56229	Cogeneration 1	Commercial CHP	AZ	CT1		9.0	8.3	6.6	Natural Gas Fired Combined Cycle	NG	CS	11	2002	Operating	TEPC	17
49949	Kinder Morgan Production Company LP	56233	EG178 Facility	CHP	TX	CT02	CC01	60.5	42.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	ERCO	14

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
49949	Kinder Morgan Production Company LP	56233	EG178 Facility	CHP	TX	CTG1	CC01	60.5	42.0	45.0	Natural Gas Fired Combined Cycle	NG	CT	6	2005	Operating	ERCO	14
49949	Kinder Morgan Production Company LP	56233	EG178 Facility	CHP	TX	STG	CC01	32.9	16.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	6	2005	Operating	ERCO	14
49950	Caithness Long Island, LLC	56234	Caithness Long Island Energy Center	IPP Non-CHP	NY	CT01	CC01	196.2	179.9	232.9	Natural Gas Fired Combined Cycle	NG	CT	8	2009	Operating	NYIS	10
49950	Caithness Long Island, LLC	56234	Caithness Long Island Energy Center	IPP Non-CHP	NY	ST01	CC01	152.7	137.0	153.0	Natural Gas Fired Combined Cycle	NG	CA	8	2009	Operating	NYIS	10
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	CT01	CC1	203.0	169.0	174.0	Natural Gas Fired Combined Cycle	NG	CT	9	2007	Operating	PACE	12
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	CT02	CC1	203.0	169.0	174.0	Natural Gas Fired Combined Cycle	NG	CT	9	2007	Operating	PACE	12
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	ST01	CC1	251.0	209.0	215.0	Natural Gas Fired Combined Cycle	NG	CA	9	2007	Operating	PACE	12
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	CT21	CC2	206.0	178.0	183.2	Natural Gas Fired Combined Cycle	NG	CT	5	2014	Operating	PACE	5
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	CT22	CC2	206.0	178.0	183.2	Natural Gas Fired Combined Cycle	NG	CT	5	2014	Operating	PACE	5
14354	PacifiCorp	56237	Lake Side Power Plant	Electric Utility	UT	ST2	CC2	316.0	273.0	281.0	Natural Gas Fired Combined Cycle	NG	CA	5	2014	Operating	PACE	5
56480	Empire Generating Co LLC	56259	Empire Generating Co LLC	IPP CHP	NY	CT11	CC1	179.0	155.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	9	2010	Operating	NYIS	9
56480	Empire Generating Co LLC	56259	Empire Generating Co LLC	IPP CHP	NY	CT12	CC1	179.0	155.0	190.0	Natural Gas Fired Combined Cycle	NG	CT	9	2010	Operating	NYIS	9
56480	Empire Generating Co LLC	56259	Empire Generating Co LLC	IPP CHP	NY	ST13	CC1	295.7	270.0	295.7	Natural Gas Fired Combined Cycle	NG	CA	9	2010	Operating	NYIS	9
16295	City of Roseville - (CA)	56298	Roseville Energy Park	Electric Utility	CA	0001	A101	42.0	38.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	11	2007	Operating	BANC	12
16295	City of Roseville - (CA)	56298	Roseville Energy Park	Electric Utility	CA	0002	A101	42.0	38.0	42.0	Natural Gas Fired Combined Cycle	NG	CT	11	2007	Operating	BANC	12
16295	City of Roseville - (CA)	56298	Roseville Energy Park	Electric Utility	CA	0003	A101	80.0	75.0	78.0	Natural Gas Fired Combined Cycle	NG	CA	11	2007	Operating	BANC	12
50130	Ashley Energy LLC	56309	Trigen St. Louis	IPP CHP	MO	CT-1	G401	7.8	5.0	7.8	Natural Gas Fired Combined Cycle	NG	CS	7	1999	Operating	MISO	20
50130	Ashley Energy LLC	56309	Trigen St. Louis	IPP CHP	MO	CT-2	G401	7.8	5.0	7.8	Natural Gas Fired Combined Cycle	NG	CS	7	1999	Operating	MISO	20
50130	Ashley Energy LLC	56309	Trigen St. Louis	IPP CHP	MO	ST-3	G401	18.2	18.0	18.0	Natural Gas Fired Combined Cycle	NG	CA	6	2000	Operating	MISO	19
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	CT2A	831	86.5	68.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	CT2B	831	86.5	68.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	CT1A	830	90.6	70.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	ERCO	12
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	CT1B	830	90.6	70.0	84.0	Natural Gas Fired Combined Cycle	NG	CT	5	2007	Operating	ERCO	12
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	ST1	830	98.1	98.1	98.1	Natural Gas Fired Combined Cycle	NG	CA	5	2007	Operating	ERCO	12
56766	CER Quail Run Energy Partners LP	56349	Quail Run Energy Center	IPP Non-CHP	TX	ST2	831	98.1	98.1	98.1	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	ERCO	11
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	CT1A	BLK1	90.0	70.0	79.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	CT1B	BLK1	90.0	62.0	72.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	CT2A	BLK2	90.0	69.0	77.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	CT2B	BLK2	90.0	63.0	73.0	Natural Gas Fired Combined Cycle	NG	CT	5	2002	Operating	ERCO	17
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	ST1	BLK1	105.1	101.0	102.0	Natural Gas Fired Combined Cycle	NG	CA	5	2007	Operating	ERCO	12
56765	CER Colorado Bend Energy Partners LP	56350	Colorado Bend Energy Center	IPP Non-CHP	TX	ST2	BLK2	115.0	103.0	108.0	Natural Gas Fired Combined Cycle	NG	CA	6	2008	Operating	ERCO	11
16088	City of Riverside - (CA)	56356	Clearwater Power Plant	Electric Utility	CA	CT1	CC1	41.0	21.0	21.0	Natural Gas Fired Combined Cycle	NG	CT	3	2005	Operating	CISO	14
16088	City of Riverside - (CA)	56356	Clearwater Power Plant	Electric Utility	CA	ST1	CC1	8.0	7.0	7.0	Natural Gas Fired Combined Cycle	NG	CA	3	2005	Operating	CISO	14
6616	Fort Pierce Utilities Authority	56400	Treasure Coast Energy Center	Electric Utility	FL	CT1	G761	219.6	158.8	188.8	Natural Gas Fired Combined Cycle	NG	CT	5	2008	Operating	FMPP	11
6616	Fort Pierce Utilities Authority	56400	Treasure Coast Energy Center	Electric Utility	FL	ST1	G761	191.8	159.2	163.3	Natural Gas Fired Combined Cycle	NG	CA	5	2008	Operating	FMPP	11
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	1A	WC1	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	8	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	1B	WC1	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	8	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	1C	WC1	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	8	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	1ST	WC1	527.0	523.0	525.0	Natural Gas Fired Combined Cycle	NG	CA	8	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	2A	WC2	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	11	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	2B	WC2	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	11	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	2C	WC2	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	11	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	2ST	WC2	527.0	523.0	525.0	Natural Gas Fired Combined Cycle	NG	CA	11	2009	Operating	FPL	10
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	3A	WC3	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	FPL	8
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	3B	WC3	298.0	244.0	282.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	FPL	8
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	3C	WC3	298.0	232.0	270.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	FPL	8
6452	Florida Power & Light Co	56407	West County Energy Center	Electric Utility	FL	3ST	WC3	527.0	523.0	527.0	Natural Gas Fired Combined Cycle	NG	CA	5	2011	Operating	FPL	8
54874	Lea Power Partners LLC	56458	Hobbs Generating Station	IPP Non-CHP	NM	CHW-T	CC1	7.2	4.3	0.0	Natural Gas Fired Combined Cycle	NG	CT	9	2008	Operating	SWPP	11
54874	Lea Power Partners LLC	56458	Hobbs Generating Station	IPP Non-CHP	NM	GT1	CC1	196.9	156.5	170.6	Natural Gas Fired Combined Cycle	NG	CT	9	2008	Operating	SWPP	11
54874	Lea Power Partners LLC	56458	Hobbs Generating Station	IPP Non-CHP	NM	GT2	CC1	196.9	156.9	169.9	Natural Gas Fired Combined Cycle	NG	CT	9	2008	Operating	SWPP	11

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
54874	Lea Power Partners LLC	56458	Hobbs Generating Station	IPP Non-CHP	NM	ST3	CC1	264.6	244.3	265.9	Natural Gas Fired Combined Cycle	NG	CA	9	2008	Operating	SWPP	11
54890	Russell City Energy Company LLC	56467	Russell City Energy Center	IPP Non-CHP	CA	CTG1	CC1	200.0	185.0	200.0	Natural Gas Fired Combined Cycle	NG	CT	8	2013	Operating	CISO	6
54890	Russell City Energy Company LLC	56467	Russell City Energy Center	IPP Non-CHP	CA	CTG2	CC1	200.0	185.0	200.0	Natural Gas Fired Combined Cycle	NG	CT	8	2013	Operating	CISO	6
54890	Russell City Energy Company LLC	56467	Russell City Energy Center	IPP Non-CHP	CA	STG1	CC1	255.0	245.0	248.0	Natural Gas Fired Combined Cycle	NG	CA	8	2013	Operating	CISO	6
14328	Pacific Gas & Electric Co.	56476	Gateway Generating Station	Electric Utility	CA	A	CC1	203.2	177.0	181.4	Natural Gas Fired Combined Cycle	NG	CT	1	2009	Operating	CISO	10
14328	Pacific Gas & Electric Co.	56476	Gateway Generating Station	Electric Utility	CA	B	CC1	203.2	177.0	181.4	Natural Gas Fired Combined Cycle	NG	CT	1	2009	Operating	CISO	10
14328	Pacific Gas & Electric Co.	56476	Gateway Generating Station	Electric Utility	CA	C	CC1	213.3	209.4	223.0	Natural Gas Fired Combined Cycle	NG	CA	1	2009	Operating	CISO	10
14328	Pacific Gas & Electric Co.	56532	Colusa Generating Station	Electric Utility	CA	A	CC1	181.5	167.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	12	2010	Operating	CISO	9
14328	Pacific Gas & Electric Co.	56532	Colusa Generating Station	Electric Utility	CA	B	CC1	181.5	167.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	12	2010	Operating	CISO	9
14328	Pacific Gas & Electric Co.	56532	Colusa Generating Station	Electric Utility	CA	C	CC1	349.4	306.0	306.0	Natural Gas Fired Combined Cycle	NG	CA	12	2010	Operating	CISO	9
17698	Southwestern Electric Power Co	56565	J Lamar Stall Unit	Electric Utility	LA	6A	CC1	184.0	160.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	SWPP	9
17698	Southwestern Electric Power Co	56565	J Lamar Stall Unit	Electric Utility	LA	6B	CC1	184.0	160.0	184.0	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	SWPP	9
17698	Southwestern Electric Power Co	56565	J Lamar Stall Unit	Electric Utility	LA	6STG	CC1	256.0	187.0	201.0	Natural Gas Fired Combined Cycle	NG	CA	6	2010	Operating	SWPP	9
1307	Basin Electric Power Coop	56610	Deer Creek Station	Electric Utility	SD	01	CCU1	154.0	150.0	150.0	Natural Gas Fired Combined Cycle	NG	CA	8	2012	Operating	SWPP	7
1307	Basin Electric Power Coop	56610	Deer Creek Station	Electric Utility	SD	02	CCU1	170.0	140.0	150.0	Natural Gas Fired Combined Cycle	NG	CT	8	2012	Operating	SWPP	7
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	IPP Non-CHP	CT	U1	CC01	199.0	177.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	ISNE	8
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	IPP Non-CHP	CT	U2	CC01	199.0	177.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	ISNE	8
56020	NRG Cedar Bayou Development Company LLC	56806	Cedar Bayou 4	IPP Non-CHP	TX	4	CBY4	178.5	172.0	185.0	Natural Gas Fired Combined Cycle	NG	CA	6	2009	Operating	ERCO	10
56020	NRG Cedar Bayou Development Company LLC	56806	Cedar Bayou 4	IPP Non-CHP	TX	41	CBY4	178.5	165.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	ERCO	10
56020	NRG Cedar Bayou Development Company LLC	56806	Cedar Bayou 4	IPP Non-CHP	TX	42	CBY4	178.5	165.0	207.0	Natural Gas Fired Combined Cycle	NG	CT	6	2009	Operating	ERCO	10
19876	Virginia Electric & Power Co	56807	Bear Garden	Electric Utility	VA	1A	CC1	145.0	190.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	PJM	8
19876	Virginia Electric & Power Co	56807	Bear Garden	Electric Utility	VA	1B	CC1	152.0	190.0	205.0	Natural Gas Fired Combined Cycle	NG	CT	5	2011	Operating	PJM	8
19876	Virginia Electric & Power Co	56807	Bear Garden	Electric Utility	VA	1C	CC1	262.0	242.0	244.0	Natural Gas Fired Combined Cycle	NG	CA	5	2011	Operating	PJM	8
56031	CPV Maryland LLC	56846	CPV St Charles Energy Center	IPP Non-CHP	MD	GTG1	G601	215.0	205.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	2	2017	Operating	PJM	2
56031	CPV Maryland LLC	56846	CPV St Charles Energy Center	IPP Non-CHP	MD	GTG2	G601	215.0	205.0	215.0	Natural Gas Fired Combined Cycle	NG	CT	2	2017	Operating	PJM	2
56031	CPV Maryland LLC	56846	CPV St Charles Energy Center	IPP Non-CHP	MD	STGEN	G601	316.0	316.0	316.0	Natural Gas Fired Combined Cycle	NG	CA	2	2017	Operating	PJM	2
56204	CPV Valley, LLC	56940	CPV Valley Energy Center	IPP Non-CHP	NY	CTG1	G921	235.0	198.2	223.0	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	NYIS	1
56204	CPV Valley, LLC	56940	CPV Valley Energy Center	IPP Non-CHP	NY	CTG2	G921	235.0	198.2	223.0	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	NYIS	1
56204	CPV Valley, LLC	56940	CPV Valley Energy Center	IPP Non-CHP	NY	STG	G921	300.0	308.7	321.0	Natural Gas Fired Combined Cycle	NG	CA	5	2018	Operating	NYIS	1
56236	West Deptford Energy LLC	56963	West Deptford Energy Station	IPP Non-CHP	NJ	E101	700	225.3	217.3	225.3	Natural Gas Fired Combined Cycle	NG	CT	10	2014	Operating	PJM	5
56236	West Deptford Energy LLC	56963	West Deptford Energy Station	IPP Non-CHP	NJ	E102	700	225.3	215.7	225.3	Natural Gas Fired Combined Cycle	NG	CT	10	2014	Operating	PJM	5
56236	West Deptford Energy LLC	56963	West Deptford Energy Station	IPP Non-CHP	NJ	STG1	700	304.0	305.9	311.0	Natural Gas Fired Combined Cycle	NG	CA	10	2014	Operating	PJM	5
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	4	PB4	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	WACM	7
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	43	PB4	20.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	1	2012	Operating	WACM	7
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	5	PB4	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	WACM	7
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	53	PB5	20.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	1	2012	Operating	WACM	7
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	6	PB5	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	WACM	7
56771	Black Hills Service Company LLC	56998	Pueblo Airport Generating Station	IPP Non-CHP	CO	7	PB5	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	1	2012	Operating	WACM	7
9191	Idaho Power Co	57028	Langley Gulch Power Plant	Electric Utility	ID	GTG	LG1	187.0	176.9	197.1	Natural Gas Fired Combined Cycle	NG	CT	6	2012	Operating	IPCO	7
9191	Idaho Power Co	57028	Langley Gulch Power Plant	Electric Utility	ID	STG	LG1	131.5	122.8	122.8	Natural Gas Fired Combined Cycle	NG	CA	6	2012	Operating	IPCO	7
3522	Chugach Electric Assn Inc	57036	Southcentral Power Project	Electric Utility	AK	1	CC10	48.8	39.8	48.8	Natural Gas Fired Combined Cycle	NG	CT	1	2013	Operating		6
3522	Chugach Electric Assn Inc	57036	Southcentral Power Project	Electric Utility	AK	2	CC10	48.8	39.8	48.8	Natural Gas Fired Combined Cycle	NG	CT	1	2013	Operating		6
3522	Chugach Electric Assn Inc	57036	Southcentral Power Project	Electric Utility	AK	3	CC10	48.8	39.8	48.8	Natural Gas Fired Combined Cycle	NG	CT	1	2013	Operating		6
3522	Chugach Electric Assn Inc	57036	Southcentral Power Project	Electric Utility	AK	4	CC10	57.5	50.3	57.0	Natural Gas Fired Combined Cycle	NG	CA	1	2013	Operating		6
12686	Mississippi Power Co	57037	Ratcliffe	Electric Utility	MS	1A	0001	235.5	680.0	742.0	Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	SOCO	5
12686	Mississippi Power Co	57037	Ratcliffe	Electric Utility	MS	1B	0001	235.5			Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	SOCO	5
12686	Mississippi Power Co	57037	Ratcliffe	Electric Utility	MS	1C	0001	369.0			Natural Gas Fired Combined Cycle	NG	CA	8	2014	Operating	SOCO	5
56427	University of California Irvine	57122	Plant	Commercial CHP	CA	CTG1	CC1	13.5	13.5	13.5	Natural Gas Fired Combined Cycle	NG	CT	7	2007	Operating	CISO	12
56427	University of California Irvine	57122	Plant	Commercial CHP	CA	STG1	CC1	5.5	5.5	5.5	Natural Gas Fired Combined Cycle	NG	CA	7	2007	Operating	CISO	12
56691	Garrison Energy Center LLC	57349	Garrison Energy Center LLC	IPP Non-CHP	DE	CTG1	GEC1	235.0	193.0	200.0	Natural Gas Fired Combined Cycle	NG	CT	6	2015	Operating	PJM	4

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
56691	Garrison Energy Center LLC	57349	Garrison Energy Center LLC	IPP Non-CHP	DE	STG2	GEC1	126.0	123.0	124.0	Natural Gas Fired Combined Cycle	NG	CA	6	2015	Operating	PJM	4
56905	Algonquin Power Sanger LLC	57564	Algonquin Power Sanger LLC	IPP Non-CHP	CA	CTG	CC1	49.0	49.0	49.0	Natural Gas Fired Combined Cycle	NG	CT	12	2007	Operating	CISO	12
56905	Algonquin Power Sanger LLC	57564	Algonquin Power Sanger LLC	IPP Non-CHP	CA	STG2	CC1	12.5	12.5	12.5	Natural Gas Fired Combined Cycle	NG	CA	5	2012	Operating	CISO	7
56918	University of California San Diego	57584	University of California San Diego	Commercial CHP	CA	NT2	CC1	15.0	13.5	13.5	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	CISO	18
56918	University of California San Diego	57584	University of California San Diego	Commercial CHP	CA	ST1	CC1	15.0	13.5	13.5	Natural Gas Fired Combined Cycle	NG	CT	7	2001	Operating	CISO	18
56918	University of California San Diego	57584	University of California San Diego	Commercial CHP	CA	STG	CC1	3.0	3.0	3.0	Natural Gas Fired Combined Cycle	NG	CA	7	2001	Operating	CISO	18
56968	Oregon State University	57653	Oregon State University Energy Center	Commercial CHP	OR	CTG	CC1	5.5	5.2	5.5	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	BPAT	9
56968	Oregon State University	57653	Oregon State University Energy Center	Commercial CHP	OR	STG	CC1	1.0	0.5	1.0	Natural Gas Fired Combined Cycle	NG	CA	6	2010	Operating	BPAT	9
56991	Astoria Energy II LLC	57664	Astoria Energy II	IPP Non-CHP	NY	CT3	CC1	200.0	156.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	NYIS	8
56991	Astoria Energy II LLC	57664	Astoria Energy II	IPP Non-CHP	NY	CT4	CC1	200.0	156.0	188.0	Natural Gas Fired Combined Cycle	NG	CT	7	2011	Operating	NYIS	8
56991	Astoria Energy II LLC	57664	Astoria Energy II	IPP Non-CHP	NY	ST2	CC1	250.0	228.0	236.0	Natural Gas Fired Combined Cycle	NG	CA	7	2011	Operating	NYIS	8
56992	Foxwoods Resort Casino	57666	Foxwoods CoGen	Commercial CHP	CT	CT1	1	6.6	6.0	7.3	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	ISNE	9
56992	Foxwoods Resort Casino	57666	Foxwoods CoGen	Commercial CHP	CT	CT2	1	6.6	6.0	7.3	Natural Gas Fired Combined Cycle	NG	CT	6	2010	Operating	ISNE	9
56992	Foxwoods Resort Casino	57666	Foxwoods CoGen	Commercial CHP	CT	STG1	1	3.0	2.5	0.5	Natural Gas Fired Combined Cycle	NG	CA	7	2016	Operating	ISNE	3
56771	Black Hills Service Company LLC	57703	Cheyenne Prairie Generating Station	Electric Utility	WY	01A	PB1	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	10	2014	Operating	WACM	5
56771	Black Hills Service Company LLC	57703	Cheyenne Prairie Generating Station	Electric Utility	WY	01B	PB1	40.0	37.0	37.0	Natural Gas Fired Combined Cycle	NG	CT	10	2014	Operating	WACM	5
56771	Black Hills Service Company LLC	57703	Cheyenne Prairie Generating Station	Electric Utility	WY	01C	PB1	20.0	20.0	20.0	Natural Gas Fired Combined Cycle	NG	CA	10	2014	Operating	WACM	5
57109	St Joseph Energy Center LLC	57794	St Joseph Energy Center	IPP Non-CHP	IN	CT1	CC01	238.0	229.0	237.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	PJM	1
57109	St Joseph Energy Center LLC	57794	St Joseph Energy Center	IPP Non-CHP	IN	CT2	CC01	238.0	229.0	237.0	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	PJM	1
57109	St Joseph Energy Center LLC	57794	St Joseph Energy Center	IPP Non-CHP	IN	ST1	CC01	260.0	245.0	224.0	Natural Gas Fired Combined Cycle	NG	CA	4	2018	Operating	PJM	1
57166	Woodbridge Energy Center	57839	Woodbridge Energy Center	IPP Non-CHP	NJ	CT001	CC1	240.0	209.8	234.0	Natural Gas Fired Combined Cycle	NG	CT	11	2015	Operating	PJM	4
57166	Woodbridge Energy Center	57839	Woodbridge Energy Center	IPP Non-CHP	NJ	CT002	CC1	240.0	208.1	231.3	Natural Gas Fired Combined Cycle	NG	CT	10	2015	Operating	PJM	4
57166	Woodbridge Energy Center	57839	Woodbridge Energy Center	IPP Non-CHP	NJ	ST001	CC1	315.0	305.0	310.2	Natural Gas Fired Combined Cycle	NG	CA	11	2015	Operating	PJM	4
13584	NRG El Segundo Operations Inc	57901	El Segundo Energy Center LLC	IPP Non-CHP	CA	5	1011	198.0	195.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	8	2013	Operating	CISO	6
13584	NRG El Segundo Operations Inc	57901	El Segundo Energy Center LLC	IPP Non-CHP	CA	6	1011	70.7	60.0	60.0	Natural Gas Fired Combined Cycle	NG	CA	8	2013	Operating	CISO	6
13584	NRG El Segundo Operations Inc	57901	El Segundo Energy Center LLC	IPP Non-CHP	CA	7	2021	198.0	195.0	195.0	Natural Gas Fired Combined Cycle	NG	CT	7	2013	Operating	CISO	6
13584	NRG El Segundo Operations Inc	57901	El Segundo Energy Center LLC	IPP Non-CHP	CA	8	2021	70.7	60.0	60.0	Natural Gas Fired Combined Cycle	NG	CA	7	2013	Operating	CISO	6
57281	University of Cincinnati	57908	Central Utility Plant Cincinnati	Commercial CHP	OH	CTG1	CUP	11.9	12.5	12.5	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
57281	University of Cincinnati	57908	Central Utility Plant Cincinnati	Commercial CHP	OH	CTG2	CUP	11.9	12.5	12.5	Natural Gas Fired Combined Cycle	NG	CT	6	2004	Operating	PJM	15
57281	University of Cincinnati	57908	Central Utility Plant Cincinnati	Commercial CHP	OH	STG	CUP	21.5	21.5	21.5	Natural Gas Fired Combined Cycle	NG	CA	6	2004	Operating	PJM	15
57332	Roquette America	57953	Roquette America	Industrial CHP	IA	GT	CGEN	40.0	38.0	40.0	Natural Gas Fired Combined Cycle	NG	CT	7	2004	Operating	MISO	15
57332	Roquette America	57953	Roquette America	Industrial CHP	IA	HRSG	CGEN	10.0	10.0	10.0	Natural Gas Fired Combined Cycle	NG	CA	7	2004	of service	MISO	15
40613	Northern California Power Agny	57978	Lodi Energy Center	Electric Utility	CA	CT1	CC1	185.0	162.0	181.0	Natural Gas Fired Combined Cycle	NG	CT	11	2012	Operating	CISO	7
40613	Northern California Power Agny	57978	Lodi Energy Center	Electric Utility	CA	ST1	CC1	103.9	95.0	96.0	Natural Gas Fired Combined Cycle	NG	CA	11	2012	Operating	CISO	7
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	CTG-1	TMP1	232.0	211.0	230.0	Natural Gas Fired Combined Cycle	NG	CT	7	2014	Operating	ERCO	5
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	CTG-2	TMP1	232.0	211.0	230.0	Natural Gas Fired Combined Cycle	NG	CT	7	2014	Operating	ERCO	5
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	STG-1	TMP1	339.2	312.0	326.0	Natural Gas Fired Combined Cycle	NG	CA	7	2014	Operating	ERCO	5
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	CTG-3	TMP2	232.0	211.0	230.0	Natural Gas Fired Combined Cycle	NG	CT	5	2015	Operating	ERCO	4
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	CTG-4	TMP2	232.0	211.0	230.0	Natural Gas Fired Combined Cycle	NG	CT	5	2015	Operating	ERCO	4
57377	PPG - O&M Panda Temple Power LLC	58001	Panda Temple Power Station	IPP Non-CHP	TX	STG-2	TMP2	339.2	312.0	326.0	Natural Gas Fired Combined Cycle	NG	CA	5	2015	Operating	ERCO	4
57379	PPG - O&M Panda Sherman Power LLC	58005	Panda Sherman Power Station	IPP Non-CHP	TX	CTG-1	CC1	232.0	204.0	232.0	Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	ERCO	5
57379	PPG - O&M Panda Sherman Power LLC	58005	Panda Sherman Power Station	IPP Non-CHP	TX	CTG-2	CC1	232.0	204.0	232.0	Natural Gas Fired Combined Cycle	NG	CT	8	2014	Operating	ERCO	5
57379	PPG - O&M Panda Sherman Power LLC	58005	Panda Sherman Power Station	IPP Non-CHP	TX	STG-1	CC1	339.2	309.0	331.0	Natural Gas Fired Combined Cycle	NG	CA	8	2014	Operating	ERCO	5
57457	Newark Energy Center, LLC	58079	Newark Energy Center	IPP Non-CHP	NJ	GT-1	CCST	225.0	211.4	231.4	Natural Gas Fired Combined Cycle	NG	CT	9	2015	Operating	PJM	4
57457	Newark Energy Center, LLC	58079	Newark Energy Center	IPP Non-CHP	NJ	GT-2	CCST	225.0	211.3	231.5	Natural Gas Fired Combined Cycle	NG	CT	9	2015	Operating	PJM	4
57457	Newark Energy Center, LLC	58079	Newark Energy Center	IPP Non-CHP	NJ	STG-1	CCST	285.0	285.3	286.9	Natural Gas Fired Combined Cycle	NG	CA	9	2015	Operating	PJM	4
57463	Kimberly-Clark Worldwide Inc	58083	Fullerton Mill CHP	Industrial CHP	CA	GTG1	CC1	19.0	12.0	13.0	Natural Gas Fired Combined Cycle	NG	CT	7	2002	Operating	CISO	17
57463	Kimberly-Clark Worldwide Inc	58083	Fullerton Mill CHP	Industrial CHP	CA	STG1	CC1	2.0	1.0	1.0	Natural Gas Fired Combined Cycle	NG	CA	7	2002	Operating	CISO	17
57464	Kimberly-Clark Corporation	58084	Kimberly Clark-Unit 1,2,3	Industrial CHP	CT	GT100	KCNM	16.1	14.5	16.1	Natural Gas Fired Combined Cycle	NG	CT	4	2008	Operating	ISNE	11
57464	Kimberly-Clark Corporation	58084	Kimberly Clark-Unit 1,2,3	Industrial CHP	CT	GT300	KCNM	4.1	4.1	4.1	Natural Gas Fired Combined Cycle	NG	CA	12	2008	Operating	ISNE	11

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
58113	Texas A&M, Utilities & Energy Services	58151	Central Utility Plant - Texas A&M	Commercial CHP	TX	STG04	UES1	5.0	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CA	12	1956	Operating	ERCO	63
58113	Texas A&M, Utilities & Energy Services	58151	Central Utility Plant - Texas A&M	Commercial CHP	TX	GTG01	UES1	34.1	32.4	34.1	Natural Gas Fired Combined Cycle	NG	CT	8	2011	Operating	ERCO	8
58113	Texas A&M, Utilities & Energy Services	58151	Central Utility Plant - Texas A&M	Commercial CHP	TX	STG02	UES1	11.0	11.0	11.0	Natural Gas Fired Combined Cycle	NG	CA	8	2011	of service	ERCO	8
58130	University of Connecticut	58159	UCONN Cogen Facility	Commercial CHP	CT	CGT1	STG1	6.9	6.4	6.4	Natural Gas Fired Combined Cycle	NG	CT	3	2006	Operating	ISNE	13
58130	University of Connecticut	58159	UCONN Cogen Facility	Commercial CHP	CT	CGT2	STG1	6.9	6.4	6.4	Natural Gas Fired Combined Cycle	NG	CT	3	2006	Operating	ISNE	13
58130	University of Connecticut	58159	UCONN Cogen Facility	Commercial CHP	CT	CGT3	STG1	6.9	6.4	6.4	Natural Gas Fired Combined Cycle	NG	CT	3	2006	Operating	ISNE	13
58106	Western Michigan University	58161	Plant	Commercial CHP	MI	GTG-7	CC1	5.0	4.2	5.6	Natural Gas Fired Combined Cycle	NG	CT	8	1997	Operating	MISO	22
58106	Western Michigan University	58161	Plant	Commercial CHP	MI	GTG-8	CC1	5.0	4.2	5.6	Natural Gas Fired Combined Cycle	NG	CT	8	1997	Operating	MISO	22
58106	Western Michigan University	58161	Plant	Commercial CHP	MI	STG-1	CC1	0.9	0.9	0.9	Natural Gas Fired Combined Cycle	NG	CA	3	1999	Operating	MISO	20
58171	University of California-San Francisco	58198	Parnassus Central Utility Plant	Commercial CHP	CA	GTG1	CC1	4.8	5.2	5.2	Natural Gas Fired Combined Cycle	NG	CT	1	1996	Operating	CISO	23
58171	University of California-San Francisco	58198	Parnassus Central Utility Plant	Commercial CHP	CA	GTG2	CC1	4.8	5.5	5.5	Natural Gas Fired Combined Cycle	NG	CT	1	1996	Operating	CISO	23
58171	University of California-San Francisco	58198	Parnassus Central Utility Plant	Commercial CHP	CA	STG1	CC1	3.8	1.8	1.8	Natural Gas Fired Combined Cycle	NG	CA	1	1996	Operating	CISO	23
58172	NRG Energy Center Phoenix LLC	58199	Arizona State University CHP	Commercial CHP	AZ	G1		9.2	9.2	6.9	Natural Gas Fired Combined Cycle	NG	CS	4	2006	Operating	AZPS	13
58178	GSA Metropolitan Service Center	58207	Central Utility Plant at White Oak	Commercial CHP	MD	G12	CC1	5.0	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CA	2	2014	of service	PJM	5
58178	GSA Metropolitan Service Center	58207	Central Utility Plant at White Oak	Commercial CHP	MD	G7	CC1	7.5	7.5	7.5	Natural Gas Fired Combined Cycle	NG	CT	2	2014	Operating	PJM	5
58178	GSA Metropolitan Service Center	58207	Central Utility Plant at White Oak	Commercial CHP	MD	G8	CC1	7.5	7.5	7.5	Natural Gas Fired Combined Cycle	NG	CT	2	2014	Operating	PJM	5
3046	Duke Energy Progress - (NC)	58215	Lee Combined Cycle Plant	Electric Utility	NC	1A	CC1	180.0	170.0	225.0	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	DUK	7
3046	Duke Energy Progress - (NC)	58215	Lee Combined Cycle Plant	Electric Utility	NC	1B	CC1	180.0	170.0	227.0	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	DUK	7
3046	Duke Energy Progress - (NC)	58215	Lee Combined Cycle Plant	Electric Utility	NC	1C	CC1	180.0	170.0	228.0	Natural Gas Fired Combined Cycle	NG	CT	12	2012	Operating	DUK	7
3046	Duke Energy Progress - (NC)	58215	Lee Combined Cycle Plant	Electric Utility	NC	ST1	CC1	380.0	378.0	379.0	Natural Gas Fired Combined Cycle	NG	CA	12	2012	Operating	DUK	7
9417	Interstate Power and Light Co	58236	Marshalltown Generating Station	Electric Utility	IA	CTG1	MGS1	222.7	211.7	225.4	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	MISO	2
9417	Interstate Power and Light Co	58236	Marshalltown Generating Station	Electric Utility	IA	CTG2	MGS1	222.7	211.8	225.4	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	MISO	2
9417	Interstate Power and Light Co	58236	Marshalltown Generating Station	Electric Utility	IA	STG1	MGS1	260.5	230.1	233.1	Natural Gas Fired Combined Cycle	NG	CA	4	2017	Operating	MISO	2
19876	Virginia Electric & Power Co	58260	Brunswick County Power Station	Electric Utility	VA	CT01	BC01	297.5	263.9	283.3	Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	PJM	3
19876	Virginia Electric & Power Co	58260	Brunswick County Power Station	Electric Utility	VA	CT02	BC01	297.5	263.9	283.3	Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	PJM	3
19876	Virginia Electric & Power Co	58260	Brunswick County Power Station	Electric Utility	VA	CT03	BC01	297.5	263.9	283.3	Natural Gas Fired Combined Cycle	NG	CT	4	2016	Operating	PJM	3
19876	Virginia Electric & Power Co	58260	Brunswick County Power Station	Electric Utility	VA	ST01	BC01	579.7	579.4	616.3	Natural Gas Fired Combined Cycle	NG	CA	4	2016	Operating	PJM	3
58417	Panda Liberty O&M LLC	58420	Panda Liberty Generation Plant	IPP Non-CHP	PA	GEN1		435.0	378.0	425.0	Natural Gas Fired Combined Cycle	NG	CS	6	2016	Operating	PJM	3
58417	Panda Liberty O&M LLC	58420	Panda Liberty Generation Plant	IPP Non-CHP	PA	GEN2		435.0	378.0	425.0	Natural Gas Fired Combined Cycle	NG	CS	7	2016	Operating	PJM	3
58421	Panda Patriot O&M LLC	58426	Panda Patriot Generation Plant	IPP Non-CHP	PA	GEN1		435.0	382.5	425.0	Natural Gas Fired Combined Cycle	NG	CS	7	2016	Operating	PJM	3
58421	Panda Patriot O&M LLC	58426	Panda Patriot Generation Plant	IPP Non-CHP	PA	GEN2		435.0	382.5	425.0	Natural Gas Fired Combined Cycle	NG	CS	7	2016	Operating	PJM	3
56155	Lansing Board of Water and Light	58427	Lansing BWL REO Town Plant	Electric Utility	MI	CTG1	CC1	42.0	31.0	43.6	Natural Gas Fired Combined Cycle	NG	CT	7	2013	Operating	MISO	6
56155	Lansing Board of Water and Light	58427	Lansing BWL REO Town Plant	Electric Utility	MI	CTG2	CC1	42.0	31.0	43.6	Natural Gas Fired Combined Cycle	NG	CT	7	2013	Operating	MISO	6
56155	Lansing Board of Water and Light	58427	Lansing BWL REO Town Plant	Electric Utility	MI	ST	CC1	14.0	12.9	13.0	Natural Gas Fired Combined Cycle	NG	CA	7	2013	Operating	MISO	6
26253	Louisiana Energy & Power Authority	58478	LEPA Unit No. 1	Electric Utility	LA	LEPA1	LEPA	57.0	48.0	48.0	Natural Gas Fired Combined Cycle	NG	CT	6	2016	Operating	MISO	3
26253	Louisiana Energy & Power Authority	58478	LEPA Unit No. 1	Electric Utility	LA	LEPA2	LEPA	17.1	16.0	16.0	Natural Gas Fired Combined Cycle	NG	CA	6	2016	Operating	MISO	3
15248	Portland General Electric Co	58503	Carty Generating Station	Electric Utility	OR	GEN1	CCG1	300.0	246.7	279.0	Natural Gas Fired Combined Cycle	NG	CT	7	2016	Operating	PGE	3
15248	Portland General Electric Co	58503	Carty Generating Station	Electric Utility	OR	GEN2	CCG1	200.0	166.3	188.0	Natural Gas Fired Combined Cycle	NG	CA	7	2016	Operating	PGE	3
16572	Salt River Project	58557	Mesquite Generating Station Block 1	Electric Utility	AZ	GT1	BLK1	185.3	153.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SRP	16
16572	Salt River Project	58557	Mesquite Generating Station Block 1	Electric Utility	AZ	GT2	BLK1	185.3	153.0	162.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	SRP	16
16572	Salt River Project	58557	Mesquite Generating Station Block 1	Electric Utility	AZ	ST1	BLK1	321.0	289.0	300.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	SRP	16
3046	Duke Energy Progress - (NC)	58697	L V Sutton Combined Cycle	Electric Utility	NC	CA1	1	288.0	266.0	271.0	Natural Gas Fired Combined Cycle	NG	CA	11	2013	Operating	CPLE	6
3046	Duke Energy Progress - (NC)	58697	L V Sutton Combined Cycle	Electric Utility	NC	CT1	1	221.0	170.0	224.0	Natural Gas Fired Combined Cycle	NG	CT	11	2013	Operating	CPLE	6
3046	Duke Energy Progress - (NC)	58697	L V Sutton Combined Cycle	Electric Utility	NC	CT2	1	221.0	171.0	224.0	Natural Gas Fired Combined Cycle	NG	CT	11	2013	Operating	CPLE	6
58848	Green Energy Partners LLC	59004	Stonewall	IPP Non-CHP	VA	GEN1	STNL	237.0	220.0	224.0	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	PJM	2
58848	Green Energy Partners LLC	59004	Stonewall	IPP Non-CHP	VA	GEN2	STNL	237.0	220.0	224.0	Natural Gas Fired Combined Cycle	NG	CT	4	2017	Operating	PJM	2
58848	Green Energy Partners LLC	59004	Stonewall	IPP Non-CHP	VA	GEN3	STNL	338.0	326.0	322.0	Natural Gas Fired Combined Cycle	NG	CA	4	2017	Operating	PJM	2
8723	City of Holland	59093	Holland Energy Park	Electric Utility	MI	10	1012	53.1	43.1	53.1	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	MISO	2
8723	City of Holland	59093	Holland Energy Park	Electric Utility	MI	11	1012	53.1	43.1	53.1	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	MISO	2
8723	City of Holland	59093	Holland Energy Park	Electric Utility	MI	12	1012	43.2	40.9	42.9	Natural Gas Fired Combined Cycle	NG	CA	6	2017	Operating	MISO	2

Entity ID	Entity Name	Plant ID	Plant Name	Sector	Plant State	Generator ID	Unit Code	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Technology	Energy Source Code	Prime Mover Code	Operating Month	Operating Year	Status	Balancing Authority Code	Current AGE
40229	Old Dominion Electric Coop	59220	Wildcat Point Generation Facility	Electric Utility	MD	CT1	CC1	310.3	310.3	310.3	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	PJM	1
40229	Old Dominion Electric Coop	59220	Wildcat Point Generation Facility	Electric Utility	MD	CT2	CC1	310.3	310.3	310.3	Natural Gas Fired Combined Cycle	NG	CT	4	2018	Operating	PJM	1
40229	Old Dominion Electric Coop	59220	Wildcat Point Generation Facility	Electric Utility	MD	ST1	CC1	493.0	493.0	493.0	Natural Gas Fired Combined Cycle	NG	CA	4	2018	Operating	PJM	1
49913	University of Arizona	59233	Cogeneration 2	Commercial CHP	AZ	CT2		6.0	5.0	5.0	Natural Gas Fired Combined Cycle	NG	CS	11	2002	Operating	TEPC	17
59123	NTE Carolinas, LLC	59325	Kings Mountain Energy Center	IPP Non-CHP	NC	KMEC1		310.2	259.0	305.0	Natural Gas Fired Combined Cycle	NG	CT	8	2018	Operating	DUK	1
59123	NTE Carolinas, LLC	59325	Kings Mountain Energy Center	IPP Non-CHP	NC	KMEC2		233.7	227.0	208.0	Natural Gas Fired Combined Cycle	NG	CA	8	2018	Operating	DUK	1
59124	NTE Ohio LLC	59326	Middletown Energy Center	IPP Non-CHP	OH	MEC1	MCC1	310.2	257.0	305.0	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	PJM	1
59124	NTE Ohio LLC	59326	Middletown Energy Center	IPP Non-CHP	OH	MEC2	MCC1	233.7	227.0	198.0	Natural Gas Fired Combined Cycle	NG	CA	5	2018	Operating	PJM	1
60459	CXA Sundevil Power I	59338	Gila River Power Block 1	IPP Non-CHP	AZ	CTG1	PB1	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	GRMA	16
60459	CXA Sundevil Power I	59338	Gila River Power Block 1	IPP Non-CHP	AZ	CTG2	PB1	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	7	2003	Operating	GRMA	16
60459	CXA Sundevil Power I	59338	Gila River Power Block 1	IPP Non-CHP	AZ	ST9	PB1	271.0	223.0	227.0	Natural Gas Fired Combined Cycle	NG	CA	5	2003	Operating	GRMA	16
59534	Oregon Clean Energy Center	59764	Oregon Clean Energy Center	IPP Non-CHP	OH	CTG11	CC1	328.0	256.5	313.6	Natural Gas Fired Combined Cycle	NG	CT	7	2017	Operating	PJM	2
59534	Oregon Clean Energy Center	59764	Oregon Clean Energy Center	IPP Non-CHP	OH	CTG12	CC1	328.0	256.5	313.6	Natural Gas Fired Combined Cycle	NG	CT	7	2017	Operating	PJM	2
59534	Oregon Clean Energy Center	59764	Oregon Clean Energy Center	IPP Non-CHP	OH	STG10	CC1	404.0	334.6	336.2	Natural Gas Fired Combined Cycle	NG	CA	7	2017	Operating	PJM	2
59541	Carroll County Energy LLC	59773	Carroll County Energy	IPP Non-CHP	OH	CGT1	CCE1	235.5	197.3	208.3	Natural Gas Fired Combined Cycle	NG	CT	12	2017	Operating	PJM	2
59541	Carroll County Energy LLC	59773	Carroll County Energy	IPP Non-CHP	OH	CGT2	CCE1	235.5	197.3	208.3	Natural Gas Fired Combined Cycle	NG	CT	12	2017	Operating	PJM	2
59541	Carroll County Energy LLC	59773	Carroll County Energy	IPP Non-CHP	OH	SGT1	CCE1	361.3	288.0	303.8	Natural Gas Fired Combined Cycle	NG	CA	12	2017	Operating	PJM	2
24211	Tucson Electric Power Co	59784	Gila River Power Block 3	Electric Utility	AZ	CTG5	BL03	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	GRMA	16
24211	Tucson Electric Power Co	59784	Gila River Power Block 3	Electric Utility	AZ	CTG6	BL03	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	GRMA	16
24211	Tucson Electric Power Co	59784	Gila River Power Block 3	Electric Utility	AZ	ST11	BL03	271.0	223.0	227.0	Natural Gas Fired Combined Cycle	NG	CA	6	2003	Operating	GRMA	16
6035	Exelon Power	59812	Wolf Hollow II	IPP Non-CHP	TX	CGT4	BLK2	360.0	314.1	335.0	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	ERCO	2
6035	Exelon Power	59812	Wolf Hollow II	IPP Non-CHP	TX	CGT5	BLK2	360.0	317.9	335.0	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	ERCO	2
6035	Exelon Power	59812	Wolf Hollow II	IPP Non-CHP	TX	STG6	BLK2	511.2	432.0	460.0	Natural Gas Fired Combined Cycle	NG	CA	6	2017	Operating	ERCO	2
59675	Moxie Freedom LLC	59906	Moxie Freedom Generation Plant	IPP Non-CHP	PA	GEN1		529.0	490.0	521.0	Natural Gas Fired Combined Cycle	NG	CS	8	2018	Operating	PJM	1
59675	Moxie Freedom LLC	59906	Moxie Freedom Generation Plant	IPP Non-CHP	PA	GEN2		529.0	490.0	521.0	Natural Gas Fired Combined Cycle	NG	CS	9	2018	Operating	PJM	1
6035	Exelon Power	60122	Colorado Bend II	IPP Non-CHP	TX	CT7	BLK3	360.9	313.2	350.0	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	ERCO	2
6035	Exelon Power	60122	Colorado Bend II	IPP Non-CHP	TX	CT8	BLK3	360.9	313.2	350.0	Natural Gas Fired Combined Cycle	NG	CT	6	2017	Operating	ERCO	2
6035	Exelon Power	60122	Colorado Bend II	IPP Non-CHP	TX	STG9	BLK3	508.5	461.4	498.0	Natural Gas Fired Combined Cycle	NG	CA	6	2017	Operating	ERCO	2
60100	PSEG Keys Energy Center, LLC	60302	Keys Energy Center	IPP Non-CHP	MD	10	CC1	359.6	327.0	327.0	Natural Gas Fired Combined Cycle	NG	CA	7	2018	Operating	PJM	1
60100	PSEG Keys Energy Center, LLC	60302	Keys Energy Center	IPP Non-CHP	MD	11	CC1	235.5	214.0	214.0	Natural Gas Fired Combined Cycle	NG	CT	7	2018	Operating	PJM	1
60100	PSEG Keys Energy Center, LLC	60302	Keys Energy Center	IPP Non-CHP	MD	12	CC1	235.5	214.0	214.0	Natural Gas Fired Combined Cycle	NG	CT	7	2018	Operating	PJM	1
49893	Invenergy Services LLC	60357	Lackawanna Energy Center	IPP Non-CHP	PA	GEN1		555.0	465.0	493.0	Natural Gas Fired Combined Cycle	NG	CS	3	2018	Operating	PJM	1
49893	Invenergy Services LLC	60357	Lackawanna Energy Center	IPP Non-CHP	PA	GEN2		555.0	465.0	493.0	Natural Gas Fired Combined Cycle	NG	CS	10	2018	Operating	PJM	1
60162	Panda Hummel Station LLC	60368	Panda Hummel Station LLC	IPP Non-CHP	PA	CTG1		244.8	226.3	240.8	Natural Gas Fired Combined Cycle	NG	CT	6	2018	Operating	PJM	1
60162	Panda Hummel Station LLC	60368	Panda Hummel Station LLC	IPP Non-CHP	PA	CTG2		244.8	226.3	240.8	Natural Gas Fired Combined Cycle	NG	CT	6	2018	Operating	PJM	1
60162	Panda Hummel Station LLC	60368	Panda Hummel Station LLC	IPP Non-CHP	PA	CTG3		244.8	226.3	240.8	Natural Gas Fired Combined Cycle	NG	CT	6	2018	Operating	PJM	1
60162	Panda Hummel Station LLC	60368	Panda Hummel Station LLC	IPP Non-CHP	PA	STG		460.0	417.6	405.3	Natural Gas Fired Combined Cycle	NG	CA	6	2018	Operating	PJM	1
60170	Clean Energy Future-Lordstown, LLC	60376	Clean Energy Future-Lordstown, LLC	IPP Non-CHP	OH	CTG1		311.0	263.0	304.0	Natural Gas Fired Combined Cycle	NG	CT	10	2018	Operating	PJM	1
60170	Clean Energy Future-Lordstown, LLC	60376	Clean Energy Future-Lordstown, LLC	IPP Non-CHP	OH	CTG2		311.0	263.0	304.0	Natural Gas Fired Combined Cycle	NG	CT	10	2018	Operating	PJM	1
60170	Clean Energy Future-Lordstown, LLC	60376	Clean Energy Future-Lordstown, LLC	IPP Non-CHP	OH	STG1		340.0	324.0	332.0	Natural Gas Fired Combined Cycle	NG	CA	10	2018	Operating	PJM	1
60460	CXA Sundevil Power II	60768	Gila River Power Block 2	IPP Non-CHP	AZ	CTG3	PB2	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	GRMA	16
60460	CXA Sundevil Power II	60768	Gila River Power Block 2	IPP Non-CHP	AZ	CTG4	PB2	174.0	146.0	163.0	Natural Gas Fired Combined Cycle	NG	CT	6	2003	Operating	GRMA	16
60460	CXA Sundevil Power II	60768	Gila River Power Block 2	IPP Non-CHP	AZ	ST10	PB2	271.0	223.0	227.0	Natural Gas Fired Combined Cycle	NG	CA	7	2003	Operating	GRMA	16
59928	Footprint Salem Harbor Development LP	60903	Salem Harbor Station NGCC	IPP Non-CHP	MA	1	0001	158.4	147.5	105.9	Natural Gas Fired Combined Cycle	NG	CA	5	2018	Operating	ISNE	1
59928	Footprint Salem Harbor Development LP	60903	Salem Harbor Station NGCC	IPP Non-CHP	MA	2	0002	158.4	147.5	105.9	Natural Gas Fired Combined Cycle	NG	CA	5	2018	Operating	ISNE	1
59928	Footprint Salem Harbor Development LP	60903	Salem Harbor Station NGCC	IPP Non-CHP	MA	3	0001	240.7	217.5	237.9	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	ISNE	1
59928	Footprint Salem Harbor Development LP	60903	Salem Harbor Station NGCC	IPP Non-CHP	MA	4	0002	240.7	217.5	237.9	Natural Gas Fired Combined Cycle	NG	CT	5	2018	Operating	ISNE	1

ELECTRIC POWER RESEARCH INSTITUTE

Strategies for Maintaining Fossil Assets Designated for Retirement

2012 TECHNICAL REPORT

Strategies for Maintaining Fossil Assets Designated for Retirement

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Abstract

New economic and regulatory conditions have changed the viability of continuing to operate certain fossil-fuel generating assets. Several interconnected inputs contribute to a decision that determines whether a unit will continue to operate or be placed into retirement and, ultimately, be decommissioned. These inputs can include unit efficiency, ability to meet emissions and waste regulations, necessary plant modifications, aging critical equipment, changing load demands, unit economics, and a host of other factors. It is becoming more prevalent throughout the industry to retire many of these fossil-fuel generating assets. When this decision is made, the strategy for maintaining that unit will change significantly.

This report investigates best practices for maintaining fossil-fuel generating assets after a retirement date has been designated. Specific emphasis is placed on guidelines for ensuring that these assets remain safe and reliable during this transition phase. This report draws on the knowledge gained by European experiences with performing plant closures based on the legislation passed to date. It is intended to provide a high-level framework for considerations that must be taken into account after an asset has been designated for retirement.

Keywords
Asset retirement
Change management
Fossil-fired power plants
Maintenance strategies
Strategic maintenance
Tactical maintenance

Abbreviations and Acronyms

BI	business interruption
CCTV	closed-circuit television
CMMS	computerized maintenance management system
EPRI	Electrical Power Research institute
EU	European Union
FFS	fitness for service
FOR	forced outage rate
FMECA	failure mode effects and criticality analysis
GWe	gigawatt electric
GWth	gigawatt thermal
HP	high pressure
HSE	health, safety, and environment
IP	intermediate pressure
KPI	key performance indicator
LCPD	Large Combustion Plant Directive
LP	low pressure
NDT	nondestructive testing
O&M	operations and maintenance
RCM	reliability-centered maintenance
ROL	reorder level
ROQ	reorder quantity
PM	preventive maintenance

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Section 1: Introduction

Background

In the evolving landscape of electric power generation, new economic and regulatory conditions have changed the viability of continuing to operate certain fossil-fuel generating assets. Several interconnected inputs contribute to a decision that determines whether a unit will continue to operate or be placed into retirement and, ultimately, decommissioned. These inputs can include unit efficiency, ability to meet emissions and waste regulations, necessary plant modifications, aging critical equipment, changing load demands, unit economics, and a host of other factors. It is becoming more prevalent throughout the industry to retire many of these fossil-fuel generating assets. When this decision is made, the strategy for maintaining that unit will change significantly.

Before this decision, most plant maintenance strategies implicitly function under a premise of almost indefinite plant operation. Preventive maintenance (PM) activities take place at intervals that are intended to minimize the rate of failures as much as economically possible, investments are made in the asset to promote long-term reliable operation, and resources are committed to that unit. When the decision to retire a unit is made, this strategy changes. Long-term investments are no longer made, resources are not as available, staff begins a phasing-out process, and PM activities take on a new dynamic. Despite this, units are still expected to remain safe and reliable.

Changing Landscape of Electric Power Generation

As climate change awareness continues to be a growing facet of modern society, greater emphasis is being placed on actions taken to address concerns regarding this issue. Legislators and regulatory agencies are making this an increasing element of new policy, and legislation concerning emissions regulations either has already been passed or is on the horizon. Companies are also taking proactive steps to become more environmentally conscious and reduce their carbon footprint.

This movement has had, and will continue to have, a profound effect on the electric power generation industry. As of December 2011, several power generators in the United States have announced significant levels of fossil-fuel generation capacity retirement and/or retrofitting. Some examples include the following:

- Exelon, 933 MW_e by 2011
- Southern Company (Georgia Power), 658 MW_e by 2013
- American Electric Power, 6000 MW_e by 2014
- Duke Energy, 3200 MW_e by 2015
- Tennessee Valley Authority, 2700 MW_e by 2017
- CPS Energy, 932 MW_e by 2018
- Progress Energy, 2400 MW_e by 2020

Similarly, states within the European Union (EU) have created legislation that introduces mandatory closure dates for generating assets that are not compliant with new emission regulations. Specifically, in 2001, the EU passed Directive 2001/80/EC, commonly referred to as the *Large Combustion Plant Directive (LCPD)* [1]. This landmark legislation introduced specific emissions limitations for the atmospheric pollutants sulfur dioxide, nitrogen oxides, and dust. Included in this legislation is a mandate requiring generating assets that do not intend to comply with these regulations to opt out. Opting out, in the case of the LCPD, automatically established an asset retirement period beginning January 1, 2008, and concluding after 20,000 operating hours or December 31, 2015, whichever came first [1].

In 2010, the EU further advanced their regulations on plant emissions by replacing the LCPD and other related legislation with Directive 2010/75/EU, commonly referred to as the *Industrial Emissions Directive* [2]. Among other things, this piece of legislation reduces acceptable emissions limitations to levels lower than those required by the LCPD and similar regulations. It also offers an option to opt out, referred to as the *Life Time Derogation Plan*, which requires plant operators to declare by January 1, 2014, whether they intend to comply with new standards. If they do not intend to comply, the asset retirement period begins January 1, 2016, and concludes after 17,500 operating hours or December 31, 2023, whichever comes first [2].

This has had a significant impact on the European electric power generation landscape. It is estimated that 205 plants opted out of the 2001 LCPD legislation, electing retirement by no later than December 31, 2015. This represents approximately 130 GW_{th} of generating capacity. Assuming conservative efficiency estimations on these units (20% to 25% total plant efficiency or 13,500 to 17,500 BTU/kWh heat rates), that represents approximately 35 GW_e of generating capacity. The United Kingdom alone stands to retire an estimated 35 GW_{th} (or approximately 12 GW_e) [3, 4].

Objective

This report investigates best practices for maintaining fossil-fuel generating assets after a retirement date has been designated. Specific emphasis is placed on guidelines for ensuring that these assets remain safe and reliable during this transition phase. This report draws on the knowledge gained by European experiences with performing plant closures based on the legislation passed to date. It is intended to provide a high-level framework for considerations that must be taken into account after an asset has been designated for retirement.

Approach

The approach to conducting this study was to first identify a knowledge source having experience with situations in which fossil-fueled assets have been assigned a retirement date and are intended to operate safely and reliably until that date. Based on the circumstances brought on by European legislation, it was deemed appropriate to identify an organization that has extensive experience dealing with the European fleets since the ratification of the LCPD legislation.

Second, it was necessary to determine the scope and depth of this research. Several inputs and elements are involved in the strategies for maintaining fossil assets designated for retirement. Entire volumes of literature could be created for any one of these individual inputs or elements. It was decided that the current research would provide a baseline structure for how these elements fit together. Further research could then be tailored to address any one of these elements in greater detail, as it applies to this baseline structure.

Finally, given the knowledge base and level of detail, an organizational structure for this report was laid out. This report is intended to address the key stakeholders, their roles and responsibilities, and major factors that are immediately present after the official decision has been made to retire a fossil asset on a specified future date, including the following:

- Management
- Strategic maintenance (engineering)
- Tactical maintenance (operations and maintenance)
- Safety and environmental impacts
- Finance and other impacts

These subjects are covered in more detail in the following sections

Section 2: Management and Culture

Managing Uncertainty

When the plant is formally designated for retirement, the official announcement will probably be a confirmation of widely held and long-existing rumors. Regardless of any preconceptions or expectations, the position and outlook for the plant and all those involved becomes different following this announcement. The decision gives a certainty that everything will change as the plant moves along the path to closure.

When closure becomes a real prospect, the approach to operating and maintaining the plant and managing the associated risks will change. Operational parameters will be flexed in response to the change in customer requirements, and the associated maintenance regimes will have to adapt, often on short notice, to support the asset and its operation. Staff will become unsure of their roles, questioning how what they do aligns with the new objectives and what constitutes good performance. There is a period of uncertainty, during which the organization moves from formal to truly flexible and adaptive, that must be managed.

There might be tendencies to loosen the controls, lower the standards, and slow the pace of progress, given that the plant will now close. However, the level of risk associated with roles and responsibilities becomes more difficult, not easier. This cannot be a glide path to closure. These circumstances require more management attention to risk and focus on detail, not less.

The manager's task is to extract remaining value from the asset.

With an end point in sight, the manager will strive to take the value from the plant asset before its closure. Conceptually, the approach will be to move along the path from *use* of the asset in the routine performance of business to *utilization* (that is, a renewed focus on its efficient and effective use) and ultimately to *exploitation*, in which every practicable advantage can be taken to extract remnant value from the asset before it closes.

Figure 2-1
Taking value from the asset

Safety is the number one priority, and its management is consistent with commercial objectives.

The business emphasis is to balance the risks and rewards of plant operations in the new commercial environment. However, it is essential that safety remains the number one priority. The plant manager must ensure that there is no compromise on safety in an environment in which staff are motivated to "sweat" the asset. Although the decision-making process might change and more commercial risk is considered, there can be no half measures or shortcuts taken with safety. Failure in the area of safety will have far-reaching effects across the business, impacting people, plant, and profits—and probably in that order.

Safety is the priority, and the plant manager must continually emphasize that point, reiterating that a plant managed well for safety is managed well for business. There can be no conflict between safety and commercial responsibilities. The clarity of arrangements required to maintain safety standards on site must be replicated in the commercial arena and the linkage should be made whenever possible—for example, when determining contract terms and conditions, operational parameters, and inspection regimes.

In addition, the plant must ensure continued adherence to environmental conditions, and there can be no unauthorized relaxation of operational standards.

Protect the integrity of the asset, the company, and the people.

The challenge for leaders and managers is to maintain the business, the standards of performance, and continuing compliance during the period before formal closure, in an environment in which business certainties diminish. The objective is to deliver full value as a business while protecting the appropriate level of asset integrity during the diminishing years of plant life and protecting the integrity of the company and its people in the long term.

These circumstances require a change process in which people act differently to improve the business. The manager must consider a full range of aspects including plant requirements and the need for continuing compliance as well as the breadth of stakeholder interests in the business. Much has been written in this area with respect to human behavioral aspects of the process. An approach is considered later, based on the work of John Kotter, who considered how leaders can best undertake this process and implement successful change [5].

Developing Strategies and Formulating Plans

Power plant life can be a function of the status of the assets themselves or, more likely, can be determined in response to shifts in the energy markets that mean it can no longer be competitive. The challenge during these times is to develop an overall strategy that guides delivery of the company's requirements during a time in which everything changes.

The power plant strategy can be determined only in conjunction with that of the owner. However, the first reference for consistency must be to the prevailing policy statements in each key area of the business—asset management; personnel; commercial and finance; and health, safety, and environment (HSE). Strategies and plans must reflect those positions and will be subject to change over time as events arise. The need for flexibility in approach should be seen in the objectives agreed to with the management team and staff.

A structured approach shows the links in policy, strategy, and plans that are required to produce a practicable performance framework.

Operating regimes, plant parameters, and load factors will require changes, and cash flows into and out of the business will fluctuate accordingly. In such circumstances, it can seem difficult to contemplate any plan that could work. However, the situation requires a structured approach that clearly shows the links between policy, strategy, plans, and budgets and incorporates visions, objectives, and targets.

Figure 2-2
Establishing the performance framework

Visions and policies allow the manager to convey intentions, providing a high-level statement of expectations, principles, and approach. Subsequent objectives and strategy explain what is to be achieved to fulfill that business vision and to comply with policy. The strategy provides the link between the vision and the plan by giving direction and guidance to enable specific plans to be developed. Plans identify the various tasks that must be implemented to deliver the strategic objectives, showing the shows resources, time scales, and responsibilities. This is, at first, a top-down approach, but it will be developed by using feedback after the initial implementation.

Strategy and objectives should define what is to be delivered and, to some extent, when; the plans will determine how it is to be done and by whom. The resources required will be accounted for in a financial plan, with responsibility for arranging resources and making it happen detailed in the local budget.

The only reason to produce these documents is to use them actively. They must be seen, recognized, understood, and used as reference points in the day-to-day running of the plant. After they are established, they provide a framework that allows the manager to monitor, review, improve, and deliver performance.

For every plan, there should be a clear statement of work to be undertaken—for example, purchase of new equipment, maintenance of specific assets, or the level of generation for the period (see Figure 2-3).

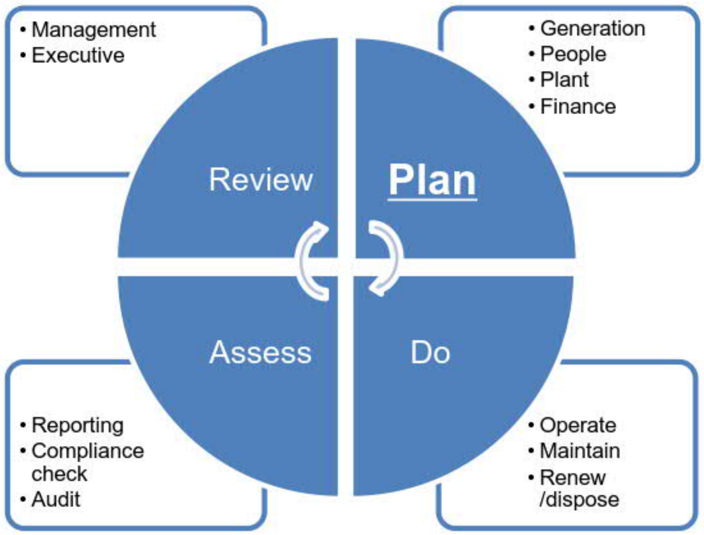

Figure 2-3
The planning cycle

Enablers and controls support the implementation of any plan.

The manager needs a range of enablers and controls that will support both the implementation of the plan and the subsequent assessment and review (see Table 2-1).

Table 2-1
Enablers and controls

Enablers and Controls
Structure, authority, and responsibilities
Management of change process
Management of documentation and information
Training, awareness, and competence
Risk management process

Individual plans are considered in the following subsections.

Communications

During times of significant change, it is essential that those affected have a clear understanding of the facts. Misinformation and rumors serve to confuse, distract, and delay. The manager must implement a systematic process of communications with stakeholders. The initial concern will be the timing of the closure, and misinformation usually errs on the side of pessimism. A coordinated communications plan is required to ensure that consistent messages are received and understood. This will include details of the content and its style of delivery, key contacts, and schedules. This formal plan to deliver the messages must be supplemented by an even more extensive exercise in which leaders across the site create frequent, informal opportunities for face-to-face contact with people in the workplace to explain the message and check understanding.

People

Only people, what they do, and how they do it can make the difference.

The physical assets designated for closure cannot change. The plant manager cannot do it alone, and the only element that can make the difference is the people. The manager must alter the way in which the organization approaches the need for change and responds to the challenges it presents. Although the manager has the technical tools of strategy, planning, and systematic process to support change, the fundamental requirement is to change people's behavior. What people do and how they respond are the keys to success during this period.

In some respects, this is exactly the wrong time to attempt to encourage renewed change, when staff are becoming more conscious of the potential for redundancies and the demise of what has now become their plant. This is a difficult time for all concerned, and the plant manager must be sensitive to their concerns.

In many respects, however, this is an opportunity to make real change that enhances the business and those associated with it. One of the objectives during this period is to protect the integrity of the company and the people. This period of change provides the opportunity to open a new phase in which the old ways of working can change, and people can develop their skills and competencies in the short term with a view to longer-term career progression either elsewhere in the company or with another employer.

The impending plant retirement means that staff will individually consider their long-term future and, depending on their personal circumstances, some might decide that it is in their best interest to leave the business. Experience shows that the most able and those with most potential find it easier to leave first. Conversely, there is unlikely to be an influx of similarly competent staff eager to join a business in the later stage of life.

Therefore, it is essential that management has a strategy and plan for human resources that provides the sustainable skills, qualifications, and experience required to support the asset until closure. Managers should consider the following:

How to retain key competencies to end of life.

- Implement a communication plan to build trust with staff, including formal and informal means
- Confirm exit arrangements as soon as possible (redundancy and pension conditions)
- Develop staff flexibility and multi-skilling; review the training plan, giving the company and staff access to enhanced skills
- Reassure staff with key competencies or potential of their future in the company beyond the life of the asset
- Identify access to other staff and services from both inside and outside the company to replace early leavers
- Use the period as a development opportunity for personnel
- Manage closure bonuses and retainers for staff

In many closure situations, the staff leave the plant proud to have completed the job, having developed personally from the experience and being confident that the competencies they have attained will give them an advantage when seeking other employment. Furthermore, people understand the commercial drivers that caused the plant's inevitable demise and appreciate the employer's efforts in looking after the workforce.

The plant manager's role is to facilitate the process, protecting the company's reputation and integrity as a good employer.

Stakeholders

Identify all stakeholders and take them with you.

In addition to the company and the staff, a range of other parties have vested interests in the power plant and much to gain or lose from its retirement. The plant manager must ensure that these groups are kept aware of the process and remain supportive.

Contractors and suppliers, in particular, will see the potential for a reduction in earnings, and the plant manager must take steps to keep them informed of significant developments and to provide confidence that the plant will be a good customer.

The regulatory authorities—especially environmental—will take an active interest in a power plant that is nearing the end of life, when it is anticipated that the plant will be starved of resources; take more operational risk; and, as emissions constraints tighten, operate nearer to the agreed limits of performance.

Local communities have an interest in the plant that will increase as they contemplate the removal of a potential nuisance or the demise of a potential employer and generator of local cash. The plant manager's role is to facilitate the process, protecting the company's reputation and integrity as a good neighbor.

Asset Management

Decide how the plant will be maintained, mindful of post-closure options.

An asset management strategy establishes a direction for the management of assets, applying the policy and helping to deliver the company strategic plan. It ensures that work on physical assets helps to deliver the company plan in an optimal way, and it requires a high-level asset management plan that shows the connection between the policy and the individual asset plans and objectives. It is important that the asset plan sets priorities and optimizes cost, risk, and performance.

The asset plan should consider options and scenarios for the plant after closure. Decisions made during the preretirement phase have impacts after closure, and it is important that, when possible, opportunities be identified to create further value for the company. Such options might include preservation of the site infrastructure to facilitate replanting, potential mothballing, transfer of individual assets to other locations, or simply considering the ultimate disposal of the site in a compliant state to obtain the best price.

Operations Planning

Consider relaxing operating conditions to preserve life while flexing plant parameters to enhance value.

Plants designated for retirement usually experience decreasing load factors and utilization as they become less economic. Rather than targeting high availability at all times, the focus is on high price periods and increasing the plant flexibility to ensure that it can respond quickly to opportunities in the market to enhance value. Operating parameters are flexed to shorten synchronization times and vary output responsively, providing customers with the power they need at the best price. Managers should also consider the scope to relax plant operating conditions to preserve plant life and retain the ability to respond quickly.

As long as marginal costs are being covered by the power price, all income contributes toward the fixed cost burden of the plant.

The focus for the preretirement phase is to rebalance the risk and reward of operations to obtain increased value from the plant. Objectives will change, and the drive for high availability and efficiency might be subordinate to being available and sufficiently flexible to capture high price periods in the market to maximize the cash flows for the business.

Staff and information flows must be able to support the new regime.

As capacity factors fall, the plant moves to two shifts, increasing the requirement for starts. As running is further reduced, the number of starts will ultimately fall. The manager should review arrangements to ensure that work patterns, competencies, and information flows are in place to ensure that staff can respond to the new regime, delivering few deviations from the required load profile and minimizing the risk of plant trips.

Compliance

Risk increases, so the compliance process must be refreshed.

The plant has entered the last phase of its life, but as circumstances become more uncertain, the risk profile increases, and there is more need to demonstrate compliance. Generally, this is viewed as continuing to meet external limits and corporate rules. In fact, it is much wider than that, and the manager must first ensure that the organization has implemented its own compliance framework covering the key risks and controls across the business. Second, the manager should ensure that staff operate within the framework. Finally, the manager must be able to demonstrate that level of compliance. In brief, (1) say what you are going to do, (2) do it, and (3) show that you have done it.

Although it important that the site culture changes and adapts to the new regime and commercial conditions, it is essential that staff operate within well-understood limits. Standards cannot be allowed to fall, and there should be increased rigor in the application of the procedural framework to protect the business, the plant, and, most importantly, the personnel.

Finance

Understand the variances in a variable business.

The finance plan accounts for the future inputs and outputs of the business in monetary terms, but there is now more uncertainty. It is more difficult to anticipate the profile of volumes and prices. However, there must be a baseline from which outcomes can be measured and understood. The manager will move toward the use of flexed budgets that reflect the changes in production and allow analysis of the variances that he or she can control and influence.

Focus on cash—reduce fixed costs.

Power plants tend to have a high proportion of fixed costs, and steps must be taken to either reduce them or convert those to variable costs, so that costs are incurred only when supporting plant operation. That might entail renegotiation and restructuring of existing term contracts and incentives.

Focus on cash— reduce project costs.

With reducing load factors, the plant will find it difficult to justify further capital investment. Clear guidance must be given to engineers to define the payback period and hurdle rate for investment appraisals. The manager must, however, be aware of the opportunities available or the risks that could be mitigated with relatively low-value investments.

Large cash expenditure schemes for procuring new assets or for major refurbishment will come under more scrutiny. In addition, steps should be taken to review the frequency, duration, and work content of major plant overhauls to optimize availability and reliability and to minimize the value locked into the plant at closure.

Focus on cash— reduce working capital.

As the plant approaches end of life, working capital in the form of fuel stocks and the inventory of spares must be managed carefully to balance the risk of business interruption during plant life with the potential for costs of disposal of redundant stock at the time of closure.

The overriding objective becomes to generate cash in the short term as the manager seeks to take value from the plant with reducing investment, even for the medium term.

Resource Management

People

Assess staff competencies and plan to sustain them to closure.

Power plants and their staff tend to age in tandem. When plant retirement is announced, the younger staff will tend to seek opportunities for the longer term elsewhere. The challenge for the manager is to ensure that the plant has sufficient resources to operate and maintain the plant safely and reliably until closure. This requires a systematic approach to establish competencies and sound leadership to ensure motivation until the end (see Figure 2-4).

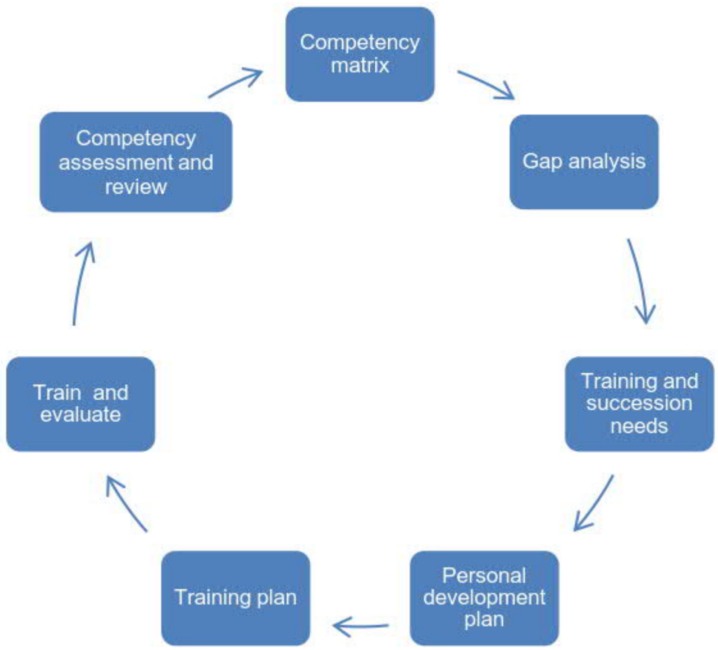

Figure 2-4
Maintaining staff competency

The first step is to establish the competencies, the number of staff, and the work patterns required to sustain the plant, given the operating regime and anticipated changes. This is undertaken in all functions.

Second, map the existing staff and competencies to the requirements and gaps identified either now or in the future, anticipating retirements and resignations. When gaps exist, there are options to train existing personnel, to recruit staff from outside, or to contract for the service with a known supplier or agency. These options should be defined, and a course of action should be determined.

From this analysis, training needs for individuals can be ascertained for the site. These requirements can be introduced into personal development plans between supervisors and staff, and an overall training plan can be developed for the site, detailing timing and resource requirements. At this stage, the manager should consider the commitment being made to training, the benefits for the staff after closure, and the reputation of the company as a caring employer in the community.

Materials and Services

Ensure that service providers are available, and use stock holdings to mitigate the risk of business interruption.

The new operating regime gives different imperatives, and it might be acceptable to take a higher risk of breakdown to avoid incurring costs of materials and services. Supply chain strategies must respond accordingly, providing new options for managers seeking to secure external resources while preserving cash in the business.

A procurement plan is required, showing the major contract services, detailing key dates and commitments, and aligning to the financial plan and budgets. Staff must work closely with suppliers to ensure that they are informed of the plant life profile and that they can position their business accordingly, so that both parties benefit.

Inventory of spares must be optimized, and holdings should be related to the risk of failure and potential lead times. Opportunities exist for alternative arrangements that mitigate business loss in the event of plant failures; for example, just-in-time deliveries, bonded and consignment stocking, or strategic spares sharing agreements with similar plants inside or outside the company.

Sourcing fuel at the right time, quality, and cost becomes more difficult as generation fluctuates in response to changing demand profiles. This requires close coordination between traders, operators, procurement, and suppliers to ensure the continuity of supplies. Anticipated generation profiles and fuel requirements must be available, continually refreshed, and communicated in response to changes in demand. The operator might be prepared to pay a contractual premium for contract flexibility that allows deliveries to be brought forward or deferred. Similarly, the supplier might be prepared to offer cost reductions if the supplier can use the site to balance a mismatch between supply and demand; for example, delivering fuel on a consignment stocking basis.

Avoid isolated fuel stocks.

It is expensive to dispose of any fuel remaining on site at closure, and stock levels require careful management in the face of fluctuating levels of generation to optimize the cost of finance and stock management and the risk to generation. In response to environmental constraints, plants might hold different qualities of fuel separately for subsequent blending to meet the emission limits at a lower cost. Care must be taken to ensure that out-of-specification fuel does not become isolated, unable to be blended, and rendered useless for the plant.

Section 3: Strategic Maintenance (Engineering)

Strategy Overview

Although the normal engineering strategy for a fossil-fired power plant is designed to maintain the asset in a condition suitable for delivering high availability and efficiency over a nominal 25-year asset life, the engineering strategy for maintaining an asset designated for retirement can be quite different.

The need to maintain the plant in a sustainable condition over a long period is no longer a core requirement; therefore, the levels of investment might be reduced. This can affect plant availability and efficiency, especially toward the end of the retirement period.

For complex installations such as fossil-fired power plants, it is common to have a defined written policy for asset management. The policy defines the assets concerned, with an overview of the means of managing, inspecting, and maintaining them over the remaining life of the power plant. As a generic document, it deals pragmatically with risk categories (HSE, business, and company reputation), recognizing that all activities carry some risk and that the objective is to manage the asset retirement in a safe, reliable manner.

Engineering strategy changes emphasis from time-based to condition-based maintenance.

To assist in delivering the optimum operation of the plant during the retirement period, the engineering strategy must change emphasis from the traditional, time-based maintenance cycle to a more condition-based inspection cycle, to reflect the reduced level of investment.

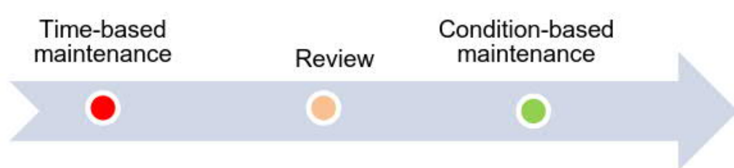

Figure 3-1
Moving from time-based to condition-based maintenance

Before retiring the time-based maintenance approach, careful consideration should be given to the potential end-of-life failure mechanisms and the consequential effects in the areas of HSE, business, and company reputation.

Plant history should be used to provide important information on the expected service life of individual components and the design life of systems with life-limiting failure mechanisms. For mechanical components, the typical failure mechanisms are aging, creep, fatigue, corrosion, and erosion. For electrical instrumentation and control components, typical failure mechanisms are aging and obsolescence.

To assist with decision making, a number of assessment processes can be adopted, such as fitness-for-service (FFS) assessments, also known as *engineering critical assessment*. An FFS assessment is a reevaluation of an item of equipment for further service, taking into account its age and condition. The assessment of FFS and remnant life can be made at any stage after the type, scale, and rate of deterioration mechanisms have been identified and considered.

Using the plant history records, FFS assessments, and local site knowledge, it is possible to establish the main life-limiting failure mechanisms and estimate the service life for the majority of components and systems.

To understand the effect of component failure and the consequential impact in the areas of HSE, business, and reputation, a risk-based scoring methodology can be adopted.

Although the methodology for risk assessments can vary among generating companies, most of them are based on the probability of an event occurring and the impact on the business if it did occur. The risk score produced is a combination of the assessed probability and the impact.

The risk assessment process should be used to determine the need for all future maintenance, with a view to cancelling all but essential work and managing the asset to retirement using the condition-based inspection approach.

The only exception to this condition-based inspection approach is for statutory HSE work, in which a time-based maintenance routine is required to maintain compliance.

Assessment Techniques

Fitness for service embraces other processes.

Several assessment techniques are available, each with a specific style and application that provide information regarding the condition of a component. Typical examples are failure mode effects and criticality analysis (FMECA) and reliability-centered maintenance (RCM).

FMECA is a process that initially identifies the failure mode of a system or component and then conducts a criticality analysis that is used to chart the probability of failure modes against the severity of their consequences.

RCM is an engineering framework that enables the definition of a complete maintenance regime. It regards maintenance as the means to determine the plant output parameters specified in the asset management plan.

The FMECA process is conducted first; it identifies the failure mode and criticality of a component. The second step of the analysis is to apply the RCM logic, which helps to determine the appropriate maintenance regime, plan, and tasks to address the identified modes of failure (see Figure 3-2).

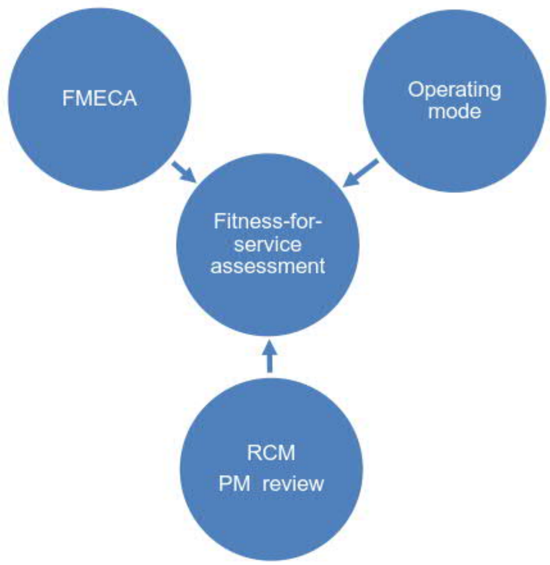

Figure 3-2
Overview of assessment techniques

An FFS assessment incorporates the output from a failure mode analysis and combines the criticality assessment of the component failure with other parameters such as safety, environment, and business interruption to determine the appropriate maintenance tasks of PM routines to maintain the plant in accordance with the asset management plan.

When no FMECA data exist, the owner should consider using groups of personnel with knowledge and experience of the operation and maintenance of the asset to determine those items that are critical for continued operations and required for compliance. This approach would also avoid any perception that the task is overly complex, encouraging staff to buy into the process to effect the changes and create "quick wins."

Fitness-for-Service Assessments

Establish the status and integrity of primary components.

FFS assessment is a reevaluation of the integrity of an item of equipment for further service, taking into account damage and deviation from design basis. The assessment of FFS and remnant life can be made at any stage after the type, scale, and rate of deterioration mechanisms have been identified (see Figure 3-3).

Figure 3-3
Options for conducting fitness-for-service assessments

During the design or before damage has been detected in service, it is necessary to identify the likelihood of damage and its subsequent deterioration, using, for example, calculation of fatigue mechanisms, nondestructive testing (NDT) reporting levels, existing test data, or experience. When damage is detected in service, the actual scale of damage as measured from NDT can be used. The rate of damage accumulation can be estimated from measurements repeated over a period of time, but being mindful that historic trends are not always a good indication of future behavior. At all stages, it is possible to carry out an FFS assessment to determine whether the equipment is safe in its current condition and what its predicted lifetime would be given that further damage might occur, as well as to define a suitable inspection and monitoring program.

If an FFS assessment has been conducted in the past, it is important to consider whether the results are still valid. It might be that the procedure used previously has been revised or superseded, and the same assessments conducted to current standards might give different results. Furthermore, materials properties can change over time due to creep and high- or low-cycle thermal fatigue.

FFS assessments are not considered suitable for control and instrumentation equipment or computer-based software systems, for which the primary deterioration mechanism is obsolescence. Figure 3-4 illustrates a typical FFS assessment process.

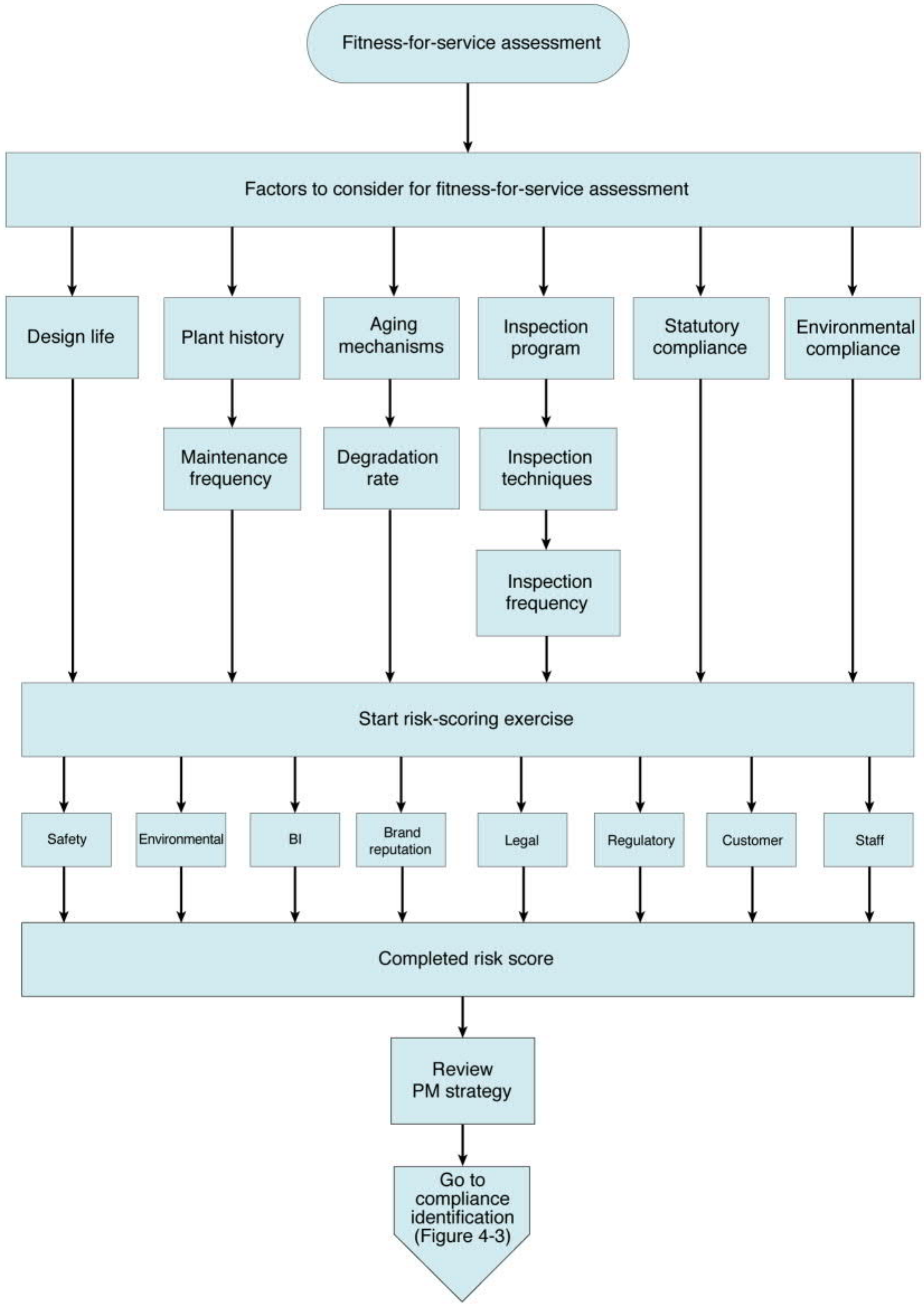

Figure 3-4
Fitness-for-service assessment flowchart

Factors to Consider for Fitness-for-Service Assessments

Design Life

Design life is affected by operational conditions.

The design life for the complete power station is usually specified in the original building contract. Typical design lives of fossil-fuel plants are in the range of 25 years or 200,000 operating hours, but many can be extended to more than 40 years with increased investment. Many individual component parts have significantly shorter design lives.

The actual life of an individual component or system is usually governed by design and operating conditions. Although the proposed life of individual components or systems can be given at the design stage, based on detailed calculations and material properties, the operational conditions can be subject to large variations over the lifetime of the component. Typical variations are temperature, pressure, stops and starts (thermal cycling), vibration, and ambient conditions.

Accurate prediction of the life of a component, therefore, requires reference to the design life, operating conditions, routine maintenance, and results of condition-based inspections.

Plant History

Plant history informs the plant status process.

Plant history should be used as a reference source for determining expected service and design life of systems with life-limiting aging mechanisms. Plant history information is usually retained in the station's maintenance management system. It contains design and manufacturing information and should also include design drawings, material and test certificates, welding and NDT specifications and reports, installation and commissioning tests, and quality assurance documents. It should also include a historical record of modifications, maintenance, replacement parts, and inspection reports (see Figure 3-5).

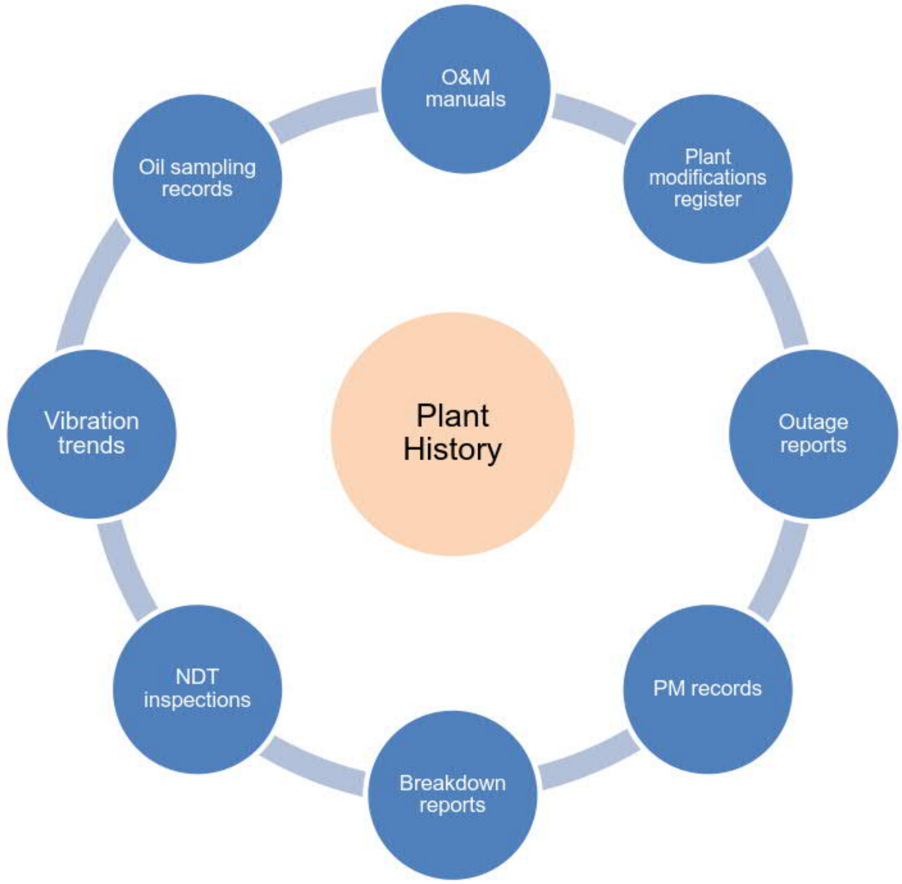

Figure 3-5
Sources of plant history information

With up-to-date records, it is possible to correlate information to build a register of the component integrity and expected future service life. This information should be used in conjunction with an FFS assessment to ensure that the correct maintenance strategy is selected.

Aging Mechanisms

A wide variety of aging mechanisms must be considered to define the optimal engineering strategy (see Figure 3-6).

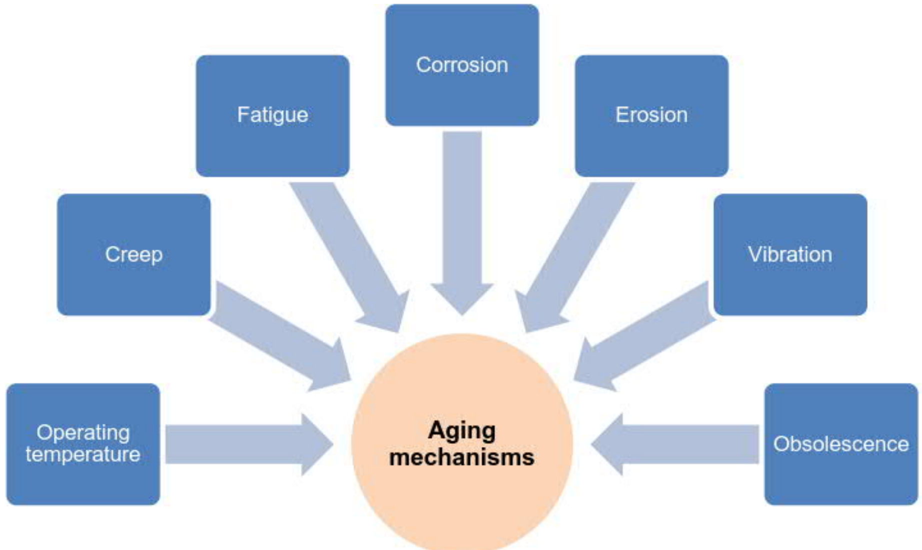

Figure 3-6
Types of aging mechanisms

Operating Temperature

Identify small deviations that have large impacts on plant life

The most common mechanism that has a significant effect on aging or the design life of a component is the operating temperature. The combustion chambers of large coal-, oil-, biomass-, or gas-fired plants operate in excess of 1832° (1000°C0, and the materials chosen in these environments operate on the limit of their mechanical properties. At these temperatures, even a relatively small increase in operating temperature, such as +50°F (+10°C), can significantly reduce the life of a component.

Steam circuits and hot gas path components also operate at elevated temperatures, and internal cooling and thermal barrier coatings are sometimes required to prevent the component from overheating.

High-temperature components are subject to conditions that mean that safe operating limits must take into account the time or the frequency of operating events. Components operating above 752°F (400°C) will be subject to creep, and components experiencing thermal transients will be subject to thermal fatigue. Ultimately, these phenomena, individually or in combination, can cause the failure of a component operating at high temperature (see Table 3-1).

Table 3-1
Components operating at high temperatures

Coal, Oil, or Biomass	Gas
High-pressure (HP) and intermediate-pressure (IP) drums, headers, and manifolds HP and IP cylinders, blades, and vanes High-temperature fasteners High-temperature valves Main steam pipework Steam chests Superheater and reheater tubes	Combustion chamber tiles Combustor cans High-temperature fasteners High-temperature valves HP and IP cylinders, blades, and vanes HP and IP drums, headers, and manifolds HP turbine blades and vanes Main steam pipework Steam chests Superheater and reheater tubes

Creep

Creep can be defined as plastic flow under a constant stress for a prolonged period of time; it generally becomes significant at temperatures above 752˚F (400°C). The creep behavior shown by a material is a function of the applied stress, the temperature, and the degree of alloying. Alloying conditions generally enhance the creep rupture strength of the base material; consequently, the higher alloying steels are used where applied stress and/or operating temperature are greatest.

Creep failures are associated with the thermally activated diffusion of micro-voids to grain boundaries in the material, where they coalesce to form cavities and intergranular fissures, ultimately leading to failure. Before this stage becomes evident, plain carbon and low-alloy steels operating above the thermal threshold for creep are subject to progressive microstructural transformation. This is a time- and temperature-dependent transformation; the component's age and operating history can be used to estimate the remaining creep life of components.

Fatigue

Fatigue is the premature fracture of metals under repeatedly applied low stresses such as bending, torsion, tension, or compression. Many materials can withstand an indefinite number of stress cycles, provided that the applied stress is below a limiting stress known as the *endurance limit*. However, the endurance limit can be affected by a corrosive environment or mechanical design features that encourage local stress concentrations.

Corrosion

Corrosion is the chemical removal of material from the surface of a component, such as boiler tubes, and where chemicals are used in a process plant or on equipment located external to buildings that are exposed directly to the environment.

Erosion

Erosion mechanisms include abrasion, normally associated with milling and transportation of fossil fuels into the boiler furnace and the byproducts of combustion, namely fly ash and furnace bottom ash.

Vibration

For fossil-fuel plants, the main sources of high cycle vibration are normally associated with the out-of-balance rotation of components such as turbines, generators, pumps, motors, and fans. Other sources of vibration are generated from the mass flow of combustion and steam systems, which can create low-cycle vibrations to casings, pipework, and associated components.

Thermal Cycling

Regular thermal cycling of fossil-fueled power plants is also known to reduce the design life of some components. The temperature change from cold to hot conditions is less critical for thin-walled components.

Obsolescence

Obsolescence—not necessarily damage—impacts electrical instrumentation and control components.

Obsolescence is associated with computer software and instrumentation systems in which advances in technology replace the existing component or in which the service or spare parts required to repair a component has been discontinued.

When aging damage is detected, a range of options are available. These options can range from scrapping the equipment or removing the damage, with or without a repair, to conducting an FFS and remnant life assessment and living safely with the damage, possibly by derating or more regular monitoring. Aging damage must be assessed, considering the potential for growth in service, but repairs are necessary only when margins are low or the data for an FFS assessment are uncertain.

Degradation Rate

Many components are reaching the upturn in the bathtub curve.

The equipment in fossil-fired power plants is exposed to conditions of stress and environment that, by design, will ultimately degrade from its original condition. Damage will accumulate until the equipment reaches a state in which it is judged to be no longer fit for service. Unless it is repaired or derated, the equipment can be said to have reached the end of its life. As damage accumulates, failures become increasingly probable; if the equipment is not withdrawn from service, breakdown of some kind will eventually occur (see Figure 3-7).

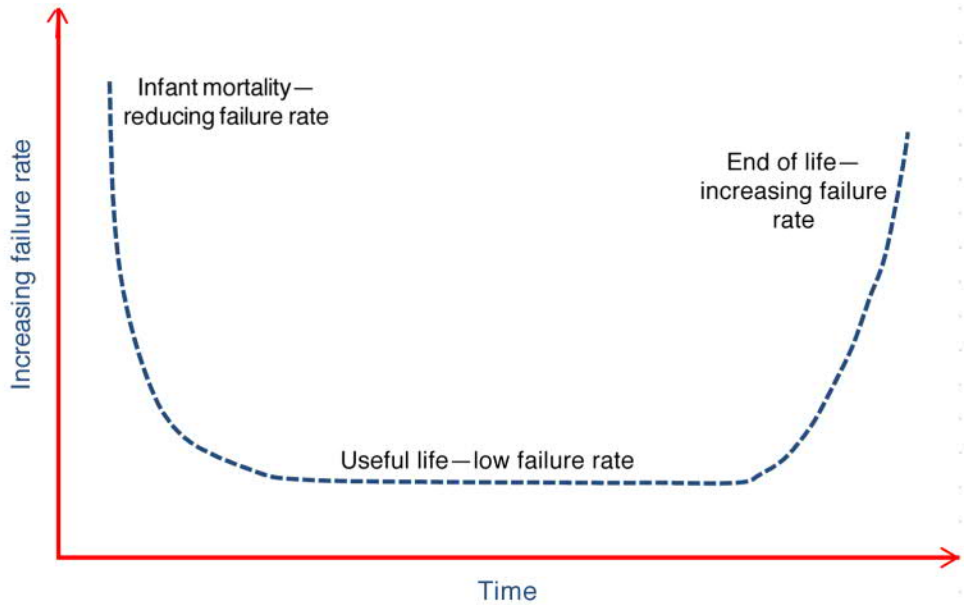

Figure 3-7
Bathtub curve, showing hypothetical failure rate versus time

The type of equipment and characteristics of duty can significantly influence the life of a component. It is not unusual for machines with moving parts to degrade rapidly and to have limited tolerance to damage and deviations from the design conditions, in terms of human error or variations in process conditions. Static equipment such as pressure vessels and pipework tends to have much greater tolerance; under benign conditions, it can remain in service for many years.

Typically, the accumulated damage and degradation rate—and, therefore, the probability that an individual component will fail—increases with time. However, this probability can be reduced by appropriate inspection, maintenance, and repair of the damaged area. The risk of failure can then oscillate between maximum and minimum risk levels, with maintenance inspection and repair becoming more frequent later in life.

Electrical control and instrumentation systems and equipment can be affected by the same degradation mechanisms as mechanical equipment, such as corrosion, erosion and fatigue, and so on. However, they can also be subject to more specific mechanisms, such as impact damage or surface abrasion, overheating, burn damage, blockage, fouling, or poisoning.

Inspection Program

To assist in monitoring fossil assets designated for retirement, it is common to adopt an inspection program for all main components.

This should be based on an initial assessment of component life followed by condition monitoring of the component at routine intervals to establish the condition of the component and its suitability for continued operation.

Inspection Techniques

Establish the inspection technique, moving from time-based to risk-based, but only when possible and allowable.

Examination, inspection, and NDT are important parts of managing equipment; they provide condition information necessary to confirm compliance within design limits or to assess fitness for service. For pressure systems and some other types of equipment, a periodic examination of inspections and other tests is a statutory requirement. Although other equipment and machinery might be exempt from regulations, the same principles of appropriate examination apply.

Inspection affects production; it is usually labor intensive, and it can, therefore, incur significant costs. For these reasons, equipment should be inspected only as necessary, and inspections should be designed to inspect in particular locations for specific conditions, measurements, defects, and flaws.

Risk-based inspection, possibly based on a failure mode and effects analysis, or at least specialist knowledge and experience, can be a good and recognized policy. When the information required to support risk-based inspection is not available, a more general inspection can be used to establish or confirm changes to the baseline condition. Schemes of examination should adapt to the age and condition of equipment and to the knowledge of its deterioration.

For pressure systems, a competent person is required to produce written schemes or to certify that existing written schemes are suitable. In general, the inspection policy must identify the approach to inspection planning and implementation and the provision of NDT services.

Most inspection policies will include visual inspection of internal and/or external surfaces. NDT will complement visual inspection for the detection of flaws that might be invisible to the naked eye. NDT can confirm and quantify expected deterioration mechanisms; when used at appropriate intervals, it provides a means for condition monitoring.

For large electrical components, the inspection techniques normally include on-line partial discharge testing, an off-line visual assessment of rotor bar insulating materials and slot wedges, and a number of high-voltage electrical tests to detect insulation breakdown between the stator core laminations. High-powered ring flux (or loop) and low-powered electromagnetic core imperfection detection tests are the primary methods used by maintenance personnel for turbo and hydro generators and large motors.

For electrical transformers that are normally not accessible for internal inspection, it is typical to take oil samples from the main tank and outlet bushings (if oil filled) to monitor any signs of dissolved gases. The presence of increasing amounts of dissolved gases is normally a sign of electrical activity within the transformer insulation; if not managed correctly, it can lead to premature failure.

Table 3-2 lists typical inspection techniques for fossil-fueled assets.

Table 3-2
Inspection techniques for fossil assets

	Inspection	Technique
Boilers	Sling rod supports Tube thickness for corrosion/erosion Header material, creep NDT of tube, header welds Boiler stop valve, body, and seats High-temperature fasteners External pipework supports Insulation	Visual Ultrasound Spark/replica test Dye pen/radiography Dye pen Calculation/elongation Visual Thermography
Unfired heat-recovery steam generators	Sling rod supports Tube fretting of support plates Header material, creep NDT of tube, header welds External pipework supports High-temperature fasteners Insulation Exhaust duct cracking	Visual Ultrasound Spark/replica test Dye pen/radiography Visual Elongation Thermography Visual/dye pen
Gas turbines	Compressor rotor, blades, and diaphragms Combustion chambers & burners Rotor, discs, diaphragms, blades, and vanes High-temperature fasteners Vibration Bearings (white metal) Lubrication oil	Dye pen Borescope/visual Dye pen Calculation/elongation On-line monitoring Ultrasound Sample/test

Table 3-2 (continued)
Inspection techniques for fossil assets

	Inspection	Technique
Steam turbines	Steam control valves, body, and seats HP, IP, low-pressure (LP) rotors, external/internal HP, IP, LP rotors, fixed and moving blades High-temperature fasteners Vibration Bearings (white metal) Lubrication oil	Dye pen Dye pen/ultrasound Dye pen Calculation/elongation On-line monitoring Ultrasound Sample/test
Generators	Shaft and end bells Windings Vibration Bearings (white metal) Lubrication oil	Dye pen On-line partial discharge On-line monitoring Ultrasound Sampling/test
Pumps	Shafts and discs Vibration Bearings (white metal) Lubrication oil	Dye pen Hand-held monitoring Ultrasound Sampling/test
Fans	Shafts and runners Vibration Bearings (white metal) Lubrication oil	Hand-held monitoring Ultrasound Sampling/test
Motors	Vibration Bearings (white metal) Lubrication oil	Hand-held monitoring Ultrasound Sampling/test
Transformers	Insulating oil	On-line gas monitors Sample/dissolved gas analysis test

Inspection Frequencies

Inspection frequency should be risk-based, when possible and allowable.

Several factors influence the period between inspections. Typically, for fossil assets, the statutory requirement to inspect the pressure systems is the primary factor in establishing the inspection period. The inspection requirements of gas turbines can also be specified in equivalent operating hours or factored fired starts.

The inspection periods of other plant items, such as steam turbines, cooling water systems, feedwater systems, and electrical equipment, are normally aligned with those of the pressure systems or gas turbines.

Having accepted that, some essential inspections and maintenance work are still required at routine intervals on assets designated for retirement. The main strategy is to minimize the work content and duration of these outages to enable the plant to meet its statutory, safety, and environmental standards with a reducing investment profile.

For asset management, it might be helpful to consider an item of equipment as having four stages in its life, each having certain characteristics and a different management, inspection, and maintenance strategy, as follows (see Figure 3-8):

- Stage 1, post-commissioning
- Stage 2, maturity
- Stage 3, aging
- Stage 4, terminal

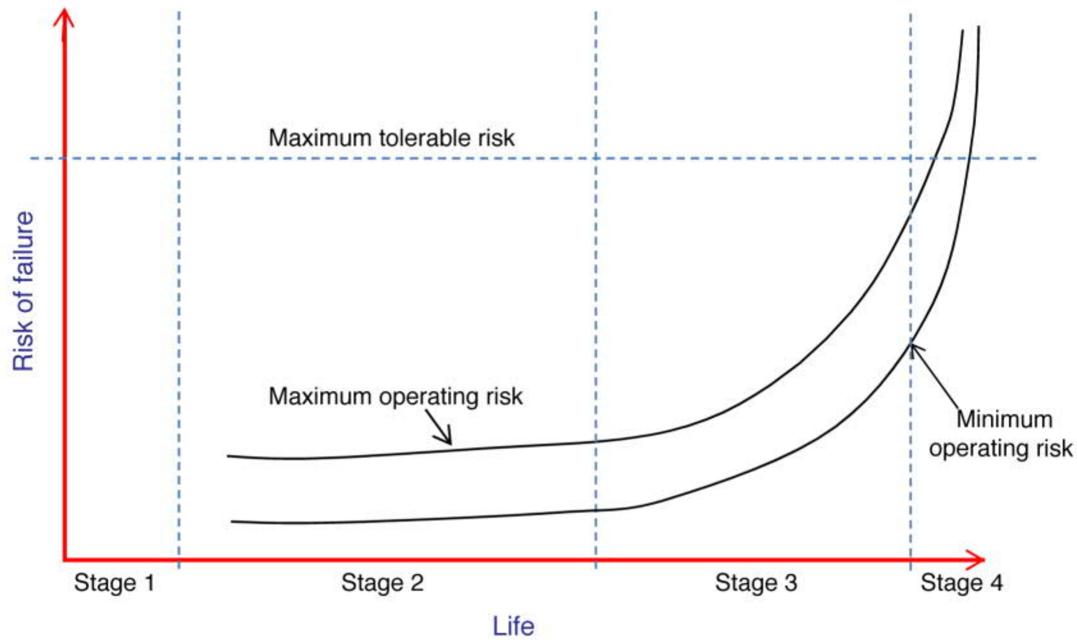

Figure 3-8
Stages of increasing risk of component failure over its life

The four stages relate to the amount of accumulated damage, the rate of degradation, and the design margins before FFS is compromised. These stages can correlate to the age of the equipment, and it would be normal for equipment to move progressively from stage 1 to stage 4 as it gets older, but this is not necessarily always the case. Some stages might not apply to some types of equipment. There are no fixed periods or clear demarcations between the stages, and it is a matter of judgment from the particular circumstances at which stage the equipment lies and the best management strategy.

Stage 1, Post-Commissioning, and Stage 2, Maturity

For fossil assets designated for retirement, it is assumed that stages 1 and 2 have been completed.

Stage 3, Aging

By this stage, the equipment has accumulated some damage, and the rate of degradation is increasing. Signs of damage and other indicators of aging are starting to appear. It becomes more important to determine quantitatively the extent and rate of damage and to make an estimate of remnant life. A more proactive approach to equipment management, inspection, and NDT is required. Design margins might be eroded, and the emphasis shifts toward FFS and remnant life assessment of specific, damaged areas.

Lack of knowledge can be a problem and can advance equipment into stage 3. Secondhand equipment is assumed to be immediately in stage 3, unless there are sufficient historical evidence and records to demonstrate a lower risk.

Stage 4, Terminal

As accumulated damage to equipment become increasingly severe, it becomes clear that the equipment will ultimately have to be repaired, refurbished, decommissioned, or replaced. The rate of degradation has become increasingly rapid and is not easy to predict. In this final, terminal stage of the equipment's life, the main emphasis is on guaranteeing adequate safety between examinations while keeping the equipment in service as long as possible. Stage 4 can be managed by more use of on-line monitoring of the damaged areas, or by more frequent NDT to monitor the sizes of flaws until they reach the maximum tolerable size, or by repairing unacceptable flaws.

A reduction of the severity of the duty—for example, reducing the pressure rating of the equipment—might be another option to maximize its usefulness before decommissioning. However, by stage 4, no guarantees can be made about future service life beyond the next examination.

Maintaining Statutory Compliance

Explore the possibility of deferring and reducing the scope of statutory inspections based on the operations profile.

Regardless of the time period before asset retirement, the engineering strategy must maintain strict compliance with all statutory, safety, and environmental standards applicable to the host country of the power plant. The strategy to be adopted must, therefore, maintain the periodic inspection of plant condition and testing and calibration of safety and environmental systems to the minimum work requirement.

Typical examples of work include routine inspection of pressure systems; routine testing of safety valves and fire detection and prevention equipment; and calibration of plant safety and control equipment to ensure that the plant will protect itself and, in extreme cases, shut down in a controlled manner. Environmental monitoring equipment should also be inspected and calibrated regularly to maintain the equipment within the specified accuracy for environmental compliance and reporting.

Although some of this work can be completed with the plant in service, the larger inspections are normally performed with the plant out of service. Traditionally, these inspections are conducted at planned periods that usually correspond with off-peak periods of low energy demand and electricity prices. However, with a low load factor, these inspections can be scheduled to suit the individual needs of the power plant or, for large utility companies, to harmonize with the inspection requirements of multiple generating units. The only essential requirement is for the inspections, testing, and calibrations to be maintained within the period specified by statutory or company standards. The following items can be challenged to reduce work scope and costs:

- Boiler tube investment
- Turbine blade replacement
- Outage duration (reduces time-based contractor site establishment)

Conversely, the following items should be preserved at the right cost:

- Inspection for continued compliance with statutory pressure regulations and insurance requirements
- HSE provisions

Insurance

As part of the asset management strategy, organizations will usually protect their businesses with insurance. Typically, an engineering insurance package for a piece of industrial equipment includes coverage for losses as a result of sudden and unforeseen damage, which would include breakdown, explosion, and collapse of the insured property.

Insurance policies do not generally cover the repair and rectification of damage due to progressive deterioration. When damage leads to sudden breakdown, such as a leak or more catastrophic failure, the insurance indemnity might depend on whether the damage was sudden and unforeseen or naturally resulting from ordinary work use and the way in which the equipment was being managed.

It is a normal condition of insurance policies that the insured must take all reasonable precautions to safeguard the insured property against loss or damage. They must maintain it in an efficient condition and take all reasonable steps to ensure that all government and other regulations relating to the operation and use of the insured property are observed. Under these circumstances, most aging mechanisms arising naturally from ordinary work use and exposure should be foreseeable.

The aging effects on a plant increase the risk of failure, plant damage, and subsequent business interruption. However, insurance premiums can be challenged if the cost of lost business decreases as the plant approaches retirement and generates at lower loads.

Risk-Based Scoring Methodology

Although there are many types of risk-based scoring systems in use in fossil-fired power plants throughout the world, the majority use a common basis for scoring the probability of occurrence of an event and the impact that the event would have if it actually happened. The score for each event can be obtained by selecting the most appropriate value from Tables 3-3 through 3-5.

Probability Rating

The probability rating seeks to measure the probability of the event taking place on a scale of 1 to 5 (see Table 3-3). It is affected not only by the nature of the event but also by the number of relevant plant items that could be affected.

Table 3-3
Risk score—probability rating

Probability Rating	Probability of Event
1	Unlikely. Remote possibility. Likelihood once in 50 years.
2	Possible, but not very likely. Likelihood once in station's life (30 years).
3	Quite possible. Likelihood once in 10 years.
4	Probable. More than likely. Likelihood once in 4 years.
5	Almost certain. Likelihood once in 2 years.

Impact Rating

The impact rating can be scored against a number of criteria, the most common being safety, environmental, and business interruption, but other criteria, such as brand/reputation, legal, regulatory, customers, and employees can be used. For each criterion, the impact score can be obtained by selecting the most appropriate value from Table 3-4.

Table 3-4
Risk score—impact rating

Criteria	1	2	3	4	5
Safety	Near miss	Minor	Important	Significant	Major/fundamental
Environment	Potential	Minor	Important	Significant	Major/fundamental (catastrophic)
Costs	<$200,000	$200,000–$2,000,000	$2,000,000–$10,000,000	$10,000,000–$20,000,000	>$20,000,000
Brand/Reputation	Limited	Regular	Regular	Major	Sustained
Legal	Limited	Limited	Vulnerability	Legal vulnerability	Legal vulnerability
Regulatory	General	Regulatory	Regulatory	Regulatory	Formal
Customers	Limited	Short-term	Significant	Significant	Significant
Employees	Local	Limited	Significant	Major	Critical

The score for each column of the table is a measure of the impact that the event would have if it actually happened. This has been called the *risk profile*. The scores in each subject area are then combined to give a final score (see Table 3-5).

Table 3-5
Risk scoring matrix

Probability Rating	Impact Rating				
	5	4	3	2	1
5	25	20	15	10	5
4	20	16	12	8	4
3	15	12	9	6	3
2	10	8	6	4	2
1	5	4	3	2	1

Example Risk Assessment

The following example shows how to calculate a risk score for the in-service failure of a generator transformer. The probability of failure is the same, regardless of the risk category. For an aging asset due for retirement, a probability score of 3 reflects the likelihood of failure within the next 10 years of operation. The impact scores, however, vary depending on the risk category, as follows:

- **Safety.** Risk of injury to people classified as minor, impact score 2.
- **Environment**. Risk of incident classified as potential, impact score 1.
- **Costs.** Uninsured losses classified as between $2 million and $10 million, impact score 3.

Costs should reflect the purchase of a new transformer (estimated at \$6 million) with a two-year lead time to manufacture and a loss of income (business interruption) for the unit of \$10,000 per day. There are also costs to remove the old transformer and refit the new transformer, estimated at \$400,000. The total cost estimate is as follows:

\$6 million + \$7.3 million (730 days × \$10,000) + \$400,000 = \$13.7 million

Table 3-6
Example risk score

	Description	Probability	Impact	Category		
				Safety	Environment	Cost
1	Generator transformer failure	3	4	6	3	12

When using the risk scores as part of FFS assessments, it is common to take forward the highest score in the assessment process but to take into consideration the other scores as supporting information.

Single Points of Failure

For fossil-fired power plants, a *single point failure* means a component for which no backup or redundancy exists and the failure of which will disable the entire unit.

Strategic Spares

On fossil assets designated for retirement, any strategic spares held on site can help mitigate the effect of an item failing in service, causing the unit to be out of service for a significant period of time. Items that are normally included as strategic spares are those that would cause a single point of failure of a unit; for example, a generator rotor or generator transformer. Strategic spares are usually high-value items with long delivery times from the manufacturers. For fossil assets designated for retirement, an in-service failure of one of these components could cause the premature retirement of a unit if a strategic spare is not available.

Donor Spares

On multiple-unit sites, if the power plant has already commenced the retirement of a unit, it can be the source of donor spares. If the units are of an identical design, a donor spare can be used in the same way as a strategic spare to help mitigate the premature retirement of a unit.

Section 4: Tactical Maintenance (Operations and Maintenance)

It is likely that a plant designated for retirement will have passed the design life expectancy and experienced a range of maintenance strategies and practices. It now requires a strategy that combines the experience of managing an aging plant and a new approach to maintenance.

Ideally the residual value of the asset at closure should be minimized, ending safe operation just before a need to incur expenditure on costly items of plant and equipment. Typically, this point is represented on the bathtub curve at the end of useful life but before wear-out begins.

Operations and maintenance teams must engage in a process to both assess the current status and determine the optimum PM strategy for the retirement period. Thereafter, a cycle of review takes place to refresh the strategy and review its impact on specific business objectives. Figure 4-1 highlights the key stages of this process.

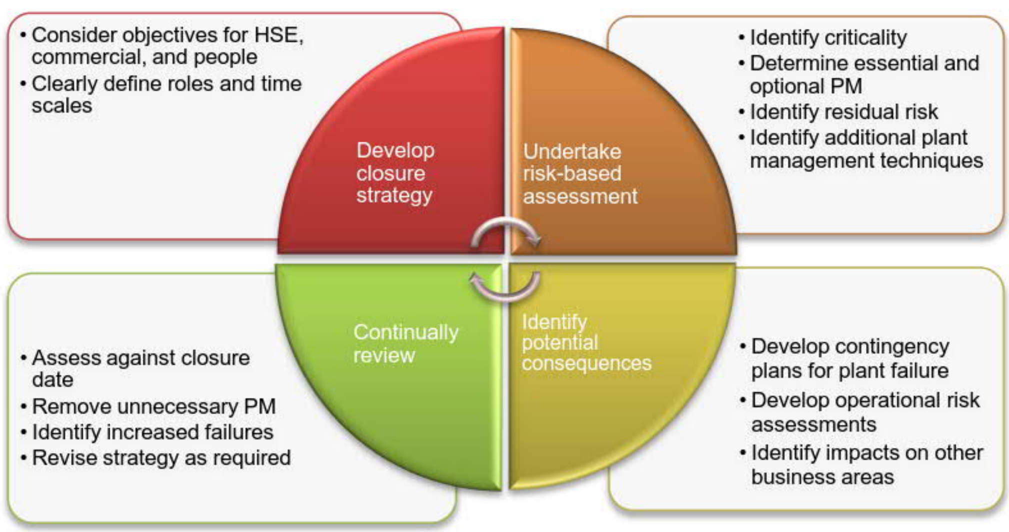

Figure 4-1
Process for changing the preventive maintenance strategy during the retirement period

Developing the Preventive Maintenance Strategy

The first priority of the PM strategy is to support the business and its established strategic objectives, particularly as it applies to commercial, HSE, and people.

Figure 4-2
Relationship of the preventive maintenance strategy to the business

The aim is to develop a PM strategy for the retirement period that supports achieving the range of business performance targets at minimum cost, while managing risk. For example, environmental performance can be delivered only if associated equipment continues to be systematically maintained and calibrated so that staff can operate the plant compliantly.

The maintenance strategy can be determined by reference to four key aspects—requirement, regime, intervention, and timing (see Table 4-1).

Table 4-1
The approach to maintenance

Requirement		Regime		Intervention		Timing
Essential (compliance or critical)		Preventive (time based)		Invasive		On load
Discretionary (performance or noncritical)	and	Predictive (condition based)	and	Noninvasive	and	Off load
Not required		Breakdown (run to failure)				

Essential and Discretionary Preventive Maintenance

It is important to differentiate between requirements for statutory compliance and for plant performance. PM can be categorized as follows:

- Essential
- Discretionary
- Not required

Essential (compliance) PM maintains the operating licenses.

Essential PM is that maintenance which is required for statutory compliance and, for example, to deliver the HSE objectives. It is common practice to allocate the highest priority to compliance-related PM; as a result, many routines remain in place for the entire operational period. Table 4-2 lists some of the key statutory compliance PM activities and indicates cases in which these activities require invasive techniques.

Table 4-2
Examples of key statutory compliance preventive maintenance

Systems, Plant, and Equipment	Invasive (Yes/No)	Requirement		
		Pressure Regulation	Health and Safety	Environmental
Pressure relief valves	No	X	X	
Emission management control	Both			X
Water systems	Both		X	X
Oil or water detection	Both			X
Fire and smoke detection	No		X	
Fire barriers	No		X	
Lifts and lifting equipment	No		X	
Access and egress	No		X	
Structures	No		X	
Mobile plant	No		X	
Safety-critical devices	No		X	

All PM strategies can be reviewed, and even compliance-based PM can be modified by challenging the content, duration, and frequency to optimize cost and risk.

Performance PM supports commercial performance.

Discretionary PM ranges from those elements of work that safeguard the operation and control of the plant at proscribed standards to those targeting improved performance. Table 4-3 provides examples of key plant performance PM activities, including important instrumentation and control work.

Table 4-3
Key preventive maintenance activities related to plant performance

Systems, Plant, and Equipment	Invasive (Yes / No)
Transmitter/analyzer calibration	Both
Tapping point blowdown	Both
Lubrication	No
Switchgear cleaning and testing	Both
Filter changeover and cleaning	Both

Managers and staff must commit time and effort to determine the appropriate solution for each plant item and consider proprietary software packages that use an RCM approach to assess criticality of systems and components to establish a risk-based interval and PM technique.

Figure 4-3 illustrates the path of questioning required to establish whether the PM is essential (compliance) or discretionary (performance). When possible, a criticality assessment should be completed to ensure that the correct risk-based conclusions are derived.

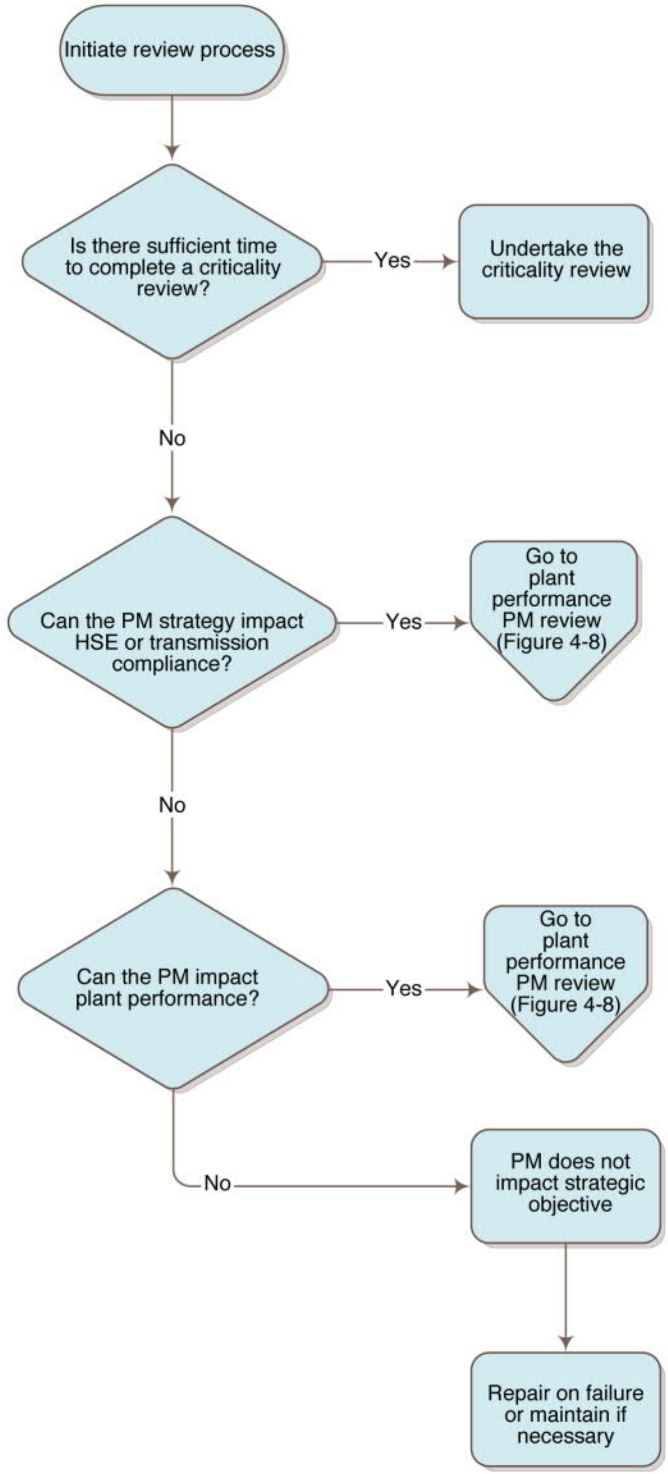

Figure 4-3
Compliance identification flowchart

Criticality Assessment

An FMECA approach can be used for each asset or asset system with the probability and impact of failure scored against safety, environment, and commercial factors and ranked using the highest or combined score of all three business aspects. From the criticality rating, it is possible to assign the appropriate maintenance tasks to an item, as follows:

- Predictive—vibration monitoring
- Noninvasive preventive—oil change
- Invasive preventive—disassembly to check wear or plant renewal

The criticality assessment requires the involvement of groups of personnel with the knowledge and experience of the operation and maintenance of the asset. It can take considerable time to determine the appropriate PM. It is unlikely that a criticality review will be appropriate for all assets at this stage of a plant lifecycle.

A less onerous approach would be to complete the assessment for the assets initially identified as compliance-related to implement the changes quickly and at lowest cost. This approach would also avoid any perception that the task is overly complex, encouraging staff to buy into the process to effect the changes and create "quick wins."

When it is determined that an asset required to ensure a certain level of plant performance does not warrant a full criticality review, an alternative route should be used to determine the appropriate PM strategy to deliver the business objectives (see Figure 4-4).

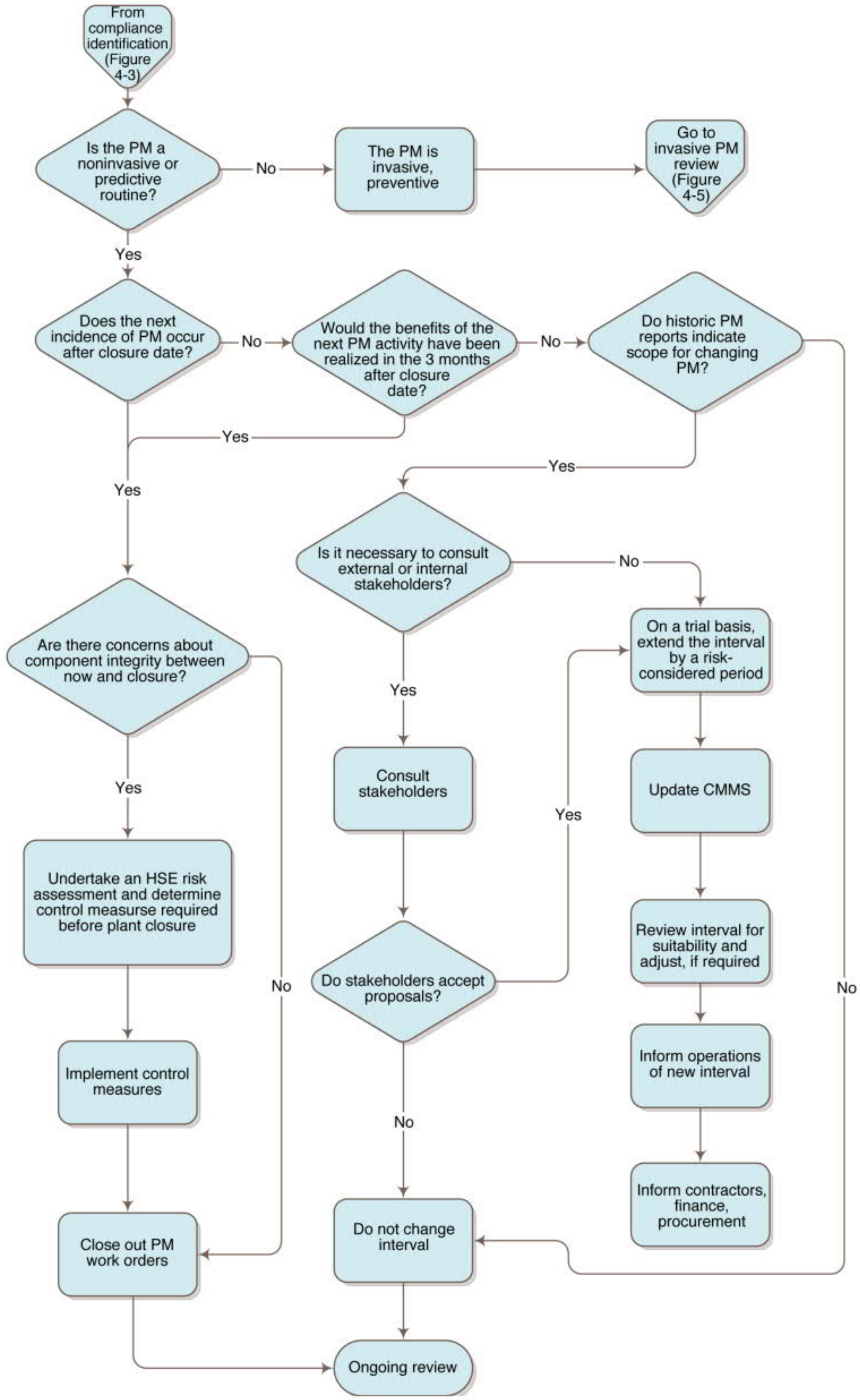

Figure 4-4
Noninvasive preventive maintenance review flowchart

An alternative process might consider the following:

- Seeking staff experience and opinion regarding the optimum interval and type of PM task
- Reviewing historic PM data for the as-found condition at the last inspection
- Reviewing failure rates

An aggressive PM strategy might consider doing nothing—running to failure and repairing, This can be a high-risk strategy with potential to impact the achievement of the business objectives. This approach would not be recommended for compliance-related PM due to the risk; for example, an environmental or safety incident with subsequent impact on the immediate business and ultimate plant life.

For a plant running to retirement, the strategic review of PM will take into account the commercial objectives and consider each of the following:

- Criticality reviews
- Experience-led proposals
- The consequences of adopting a run-to-failure strategy

It might be necessary to increase inspections and predictive analysis; for example, using condition-based maintenance. The opportunity could be taken to avoid an invasive strip-down of a pump, replacing it with a series of new vibration monitoring inspections. However, increasing the operating life of a pump and its components through vibration analysis carries a greater risk of in-service failure and a potential unplanned outage. This risk is minimized by creating a well-structured, understood, and informed condition-based maintenance strategy.

Figure 4-5 illustrates some of the fundamental requirements of a condition-based maintenance strategy. It is clear that commitment is required from the management and plant teams to make condition-based maintenance a successful element to the PM strategy.

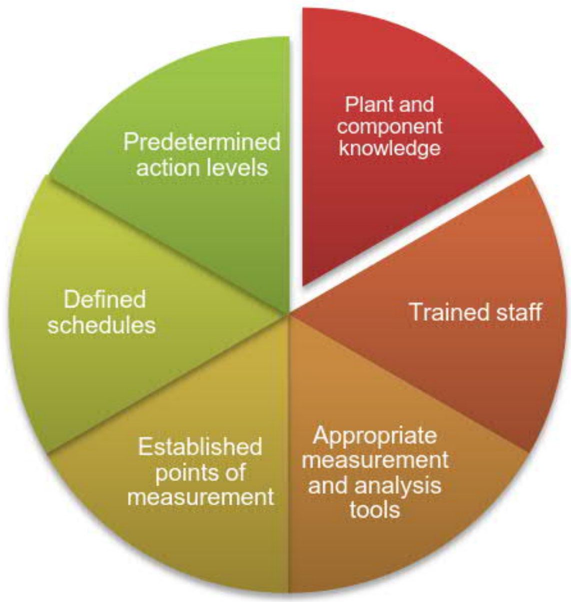

Figure 4-5
Fundamental elements of a condition-based maintenance strategy

Figure 4-6 illustrates the decision process for identifying whether a condition-based maintenance strategy can replace an invasive plant overhaul.

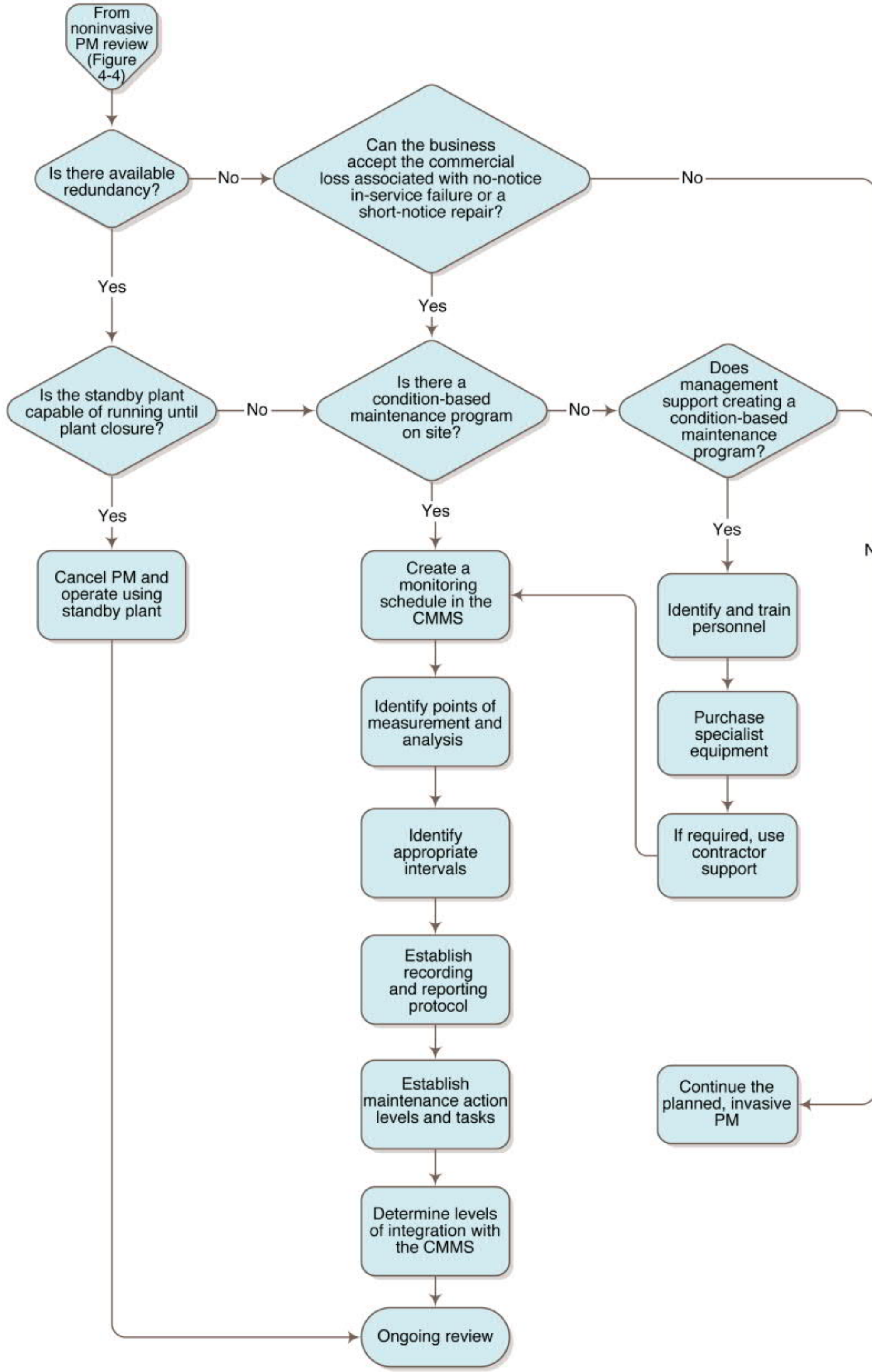

Figure 4-6
Invasive preventive maintenance review flowchart

Removal of Preventive Maintenance with Post-Retirement Impact

Figure 4-6 shows that the risk-based assessment can lead to the removal of PM from the schedule. Initial and obvious candidates are those PM activities that fall beyond the retirement date, including major overhaul of plant and equipment and routine PM activities. However, PM with effective dates before the retirement date can also be removed from the program in certain circumstances, including the following:

- The PM interval is greater than the retirement period.
- The PM interval is marginally less than the retirement period.
- The PM interval is considerably less than the retirement period and the plant or equipment is not a single point of failure.
- Systems with at least dual redundancy are used, such as pumping and filter systems.
- The PM interval is considerably less than the retirement period and the plant or equipment is a single point of failure.

These circumstances require at least one contingency measure, such as the following:

- Redrafting the insurance schedule to extend the interval between inspections.
- Completing an operational risk assessment.
- Obtaining organizational acceptance of limited or reduced plant flexibility.

Plant and equipment for which this can be applied include pipe and pressure systems; structures such as tanks, vessels, and buildings; access and egress; vents, stacks, and towers.

It will be possible to incrementally remove PM from the schedule as the retirement date approaches. To minimize expenditure, the schedule should be reviewed systematically, using the decision map.

Consequences of Minimizing Preventive Maintenance

The outcome of reassessing the PM strategies will result in the following actions:

- Adopting a schedule with extended inspection intervals
- Replacing a planned invasive inspection with a noninvasive type
- Completely removing PM when plant operating hours permits

The consequences associated with the plant include the increased risk of component failure, plant shutdown, or a safety or environmental event. In addition, there can be impacts in the processes within operations and procurement, inventory management, and contract support.

The scale of the impact depends on the nature of the modifications made to the original PM. If original schedules were too frequent and the as-found condition gave no cause for concern, there is likely to be only a marginal increase in risk. If there was evidence of plant stress and a history of failure, diminishing the maintenance regime and the nature of intervention will increase the risk of in-service failure and business losses.

Figure 4-7 illustrates the generic consequences on plant operation from a reducing PM strategy. Adapting the format of a cause and effect, fishbone diagram, Figure 4-7 enables analysis of the actual effect on the asset and potential consequences of the strategy change. The clear identification of risk helps the manager to establish mitigation measures that protect the asset and the overall business performance.

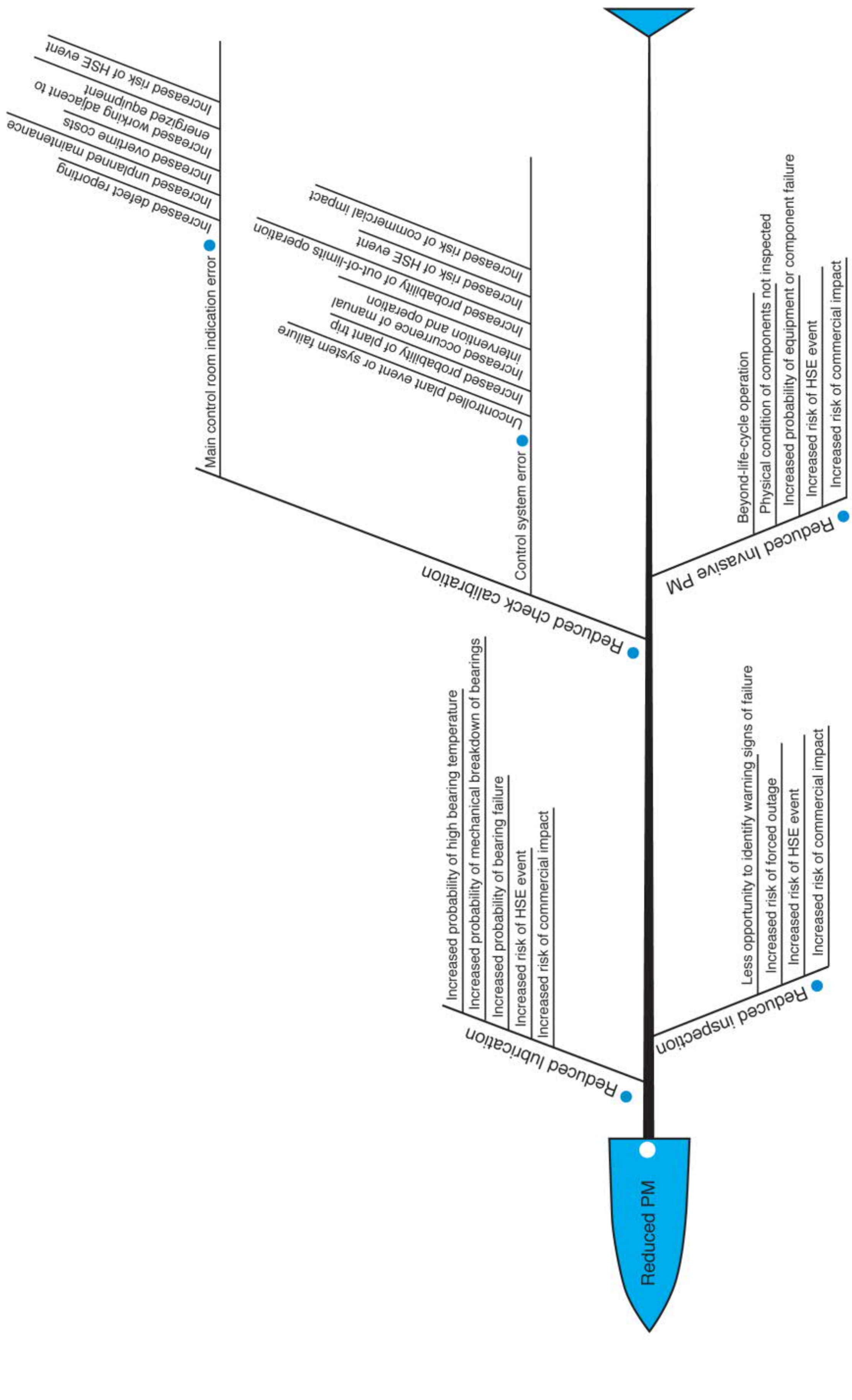

Figure 4-7
Action and consequences of reduced preventive maintenance

Figure 4-8 illustrates the process for identifying the potential PM that can impact the commercial performance of the asset. In the example of the cancelled feed pump overhaul, it is important to support the decision with a number of countermeasures, not just vibration analysis.

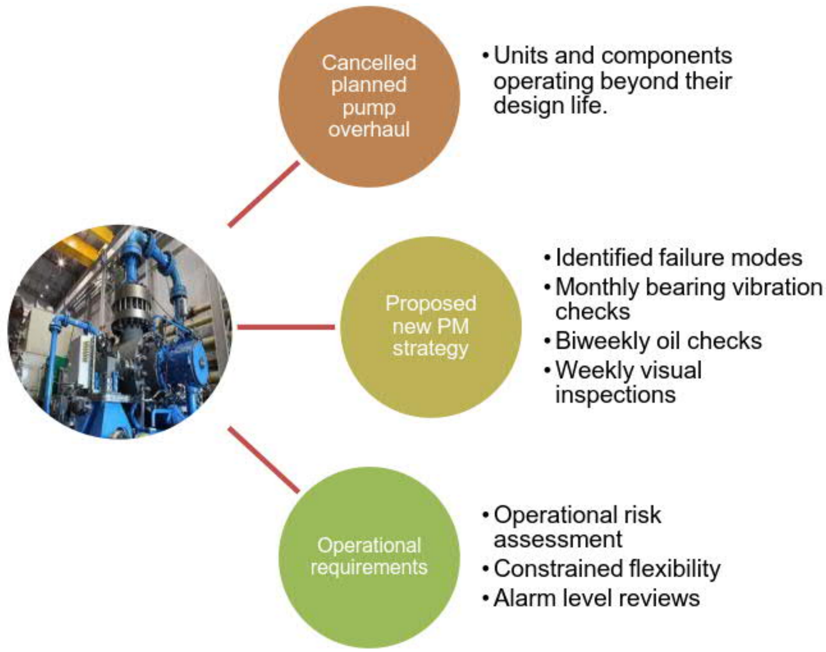

Figure 4-8
Plant performance preventive maintenance review flowchart

Figure 4-9 illustrates how the consequences of reducing PM can be mitigated for a pumping unit. The new strategy is likely to include actions from the operations and maintenance teams. Typically, the operations team can assist in increasing visual inspections or operating the feed pump to an agreed-upon set of plant parameters as defined through a standing operating instruction.

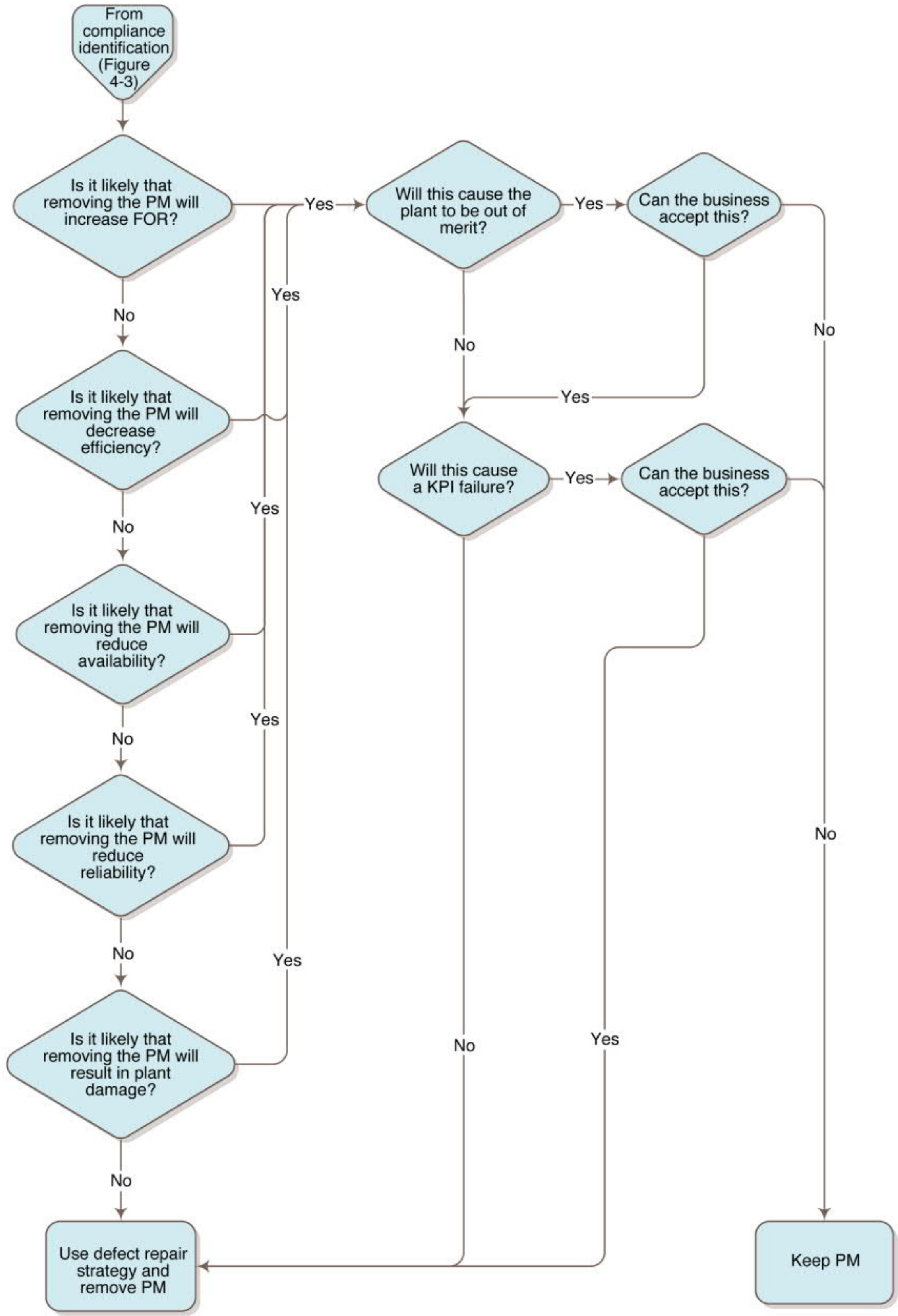

Figure 4-9
Risk mitigation for a cancelled boiler feed pump overhaul

Operating Plant and Equipment with Known Component Failures

It is not uncommon that a plant might be required to run with components having known defects or failures. Although these situations are not ideal, if they are managed well and safely, they avoid the business impact of a planned overhaul either completely or by providing planning time to arrange parts, contractors, and a commercially favorable window for the repair.

Conducting an operational risk assessment for this period is fundamental both to the decision to be able to run and how the plant will be operated thereafter. The operational risk assessment will result in a set of identified hazards and control mitigation measures and will be supported by standing instructions for the control room operators. Figure 4-10 identifies some of the control measures that maintenance and operations personnel are likely to take. A good operational risk assessment should give the plant teams confidence that the proposed operating regime for a failing plant is credible and will not result in a compliance-related event.

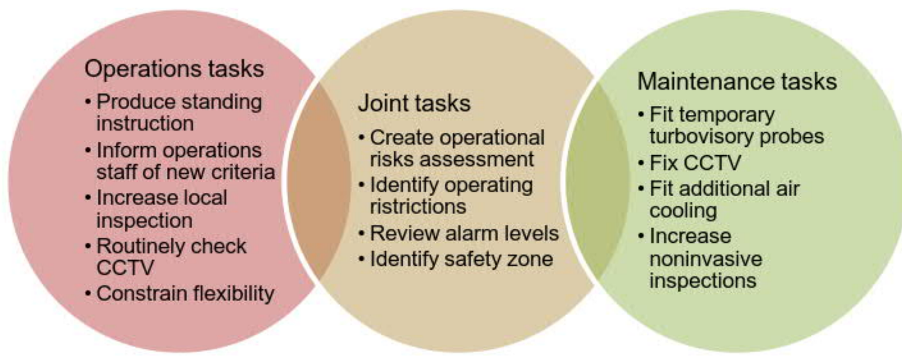

Figure 4-10
Typical operational risk assessment control activities

The Role of a Computerized Maintenance Management System

A computerized maintenance management system (CMMS) is at the core of the process described in the previous subsection. Figure 4-11 shows some of the information held in the CMMS and gives an indication of the level of detail that must be reviewed and updated through the process.

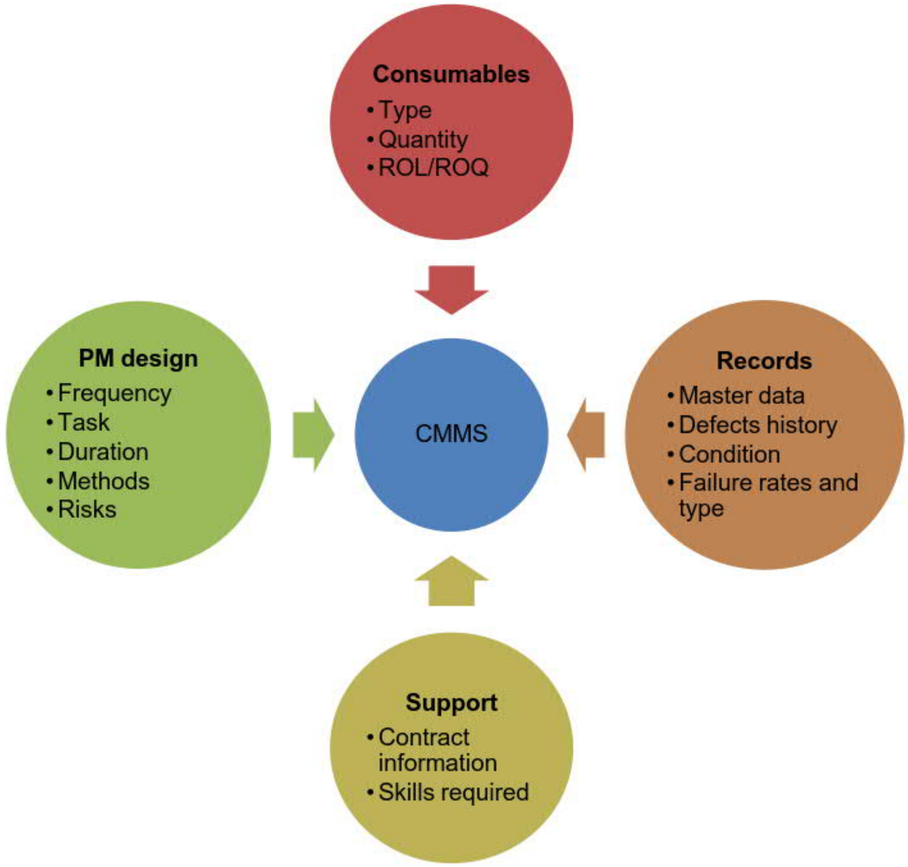

Figure 4-11
Aspects of the computerized maintenance management system data

Completing a single PM review requires a competent and experienced team member together with an experienced CMMS user/engineer. Information in the CMMS will provide the initial position for the assessments and will also retain the results. It is important that the original information be archived rather than deleted to enable a return to the original condition after a major change of plant strategy in case the new strategy should prove unsuccessful.

The importance of the CMMS and the quality of data stored within it must be maintained. Failure to accurately update the CMMS with the revised strategy and subsequent plant information will result in its poor execution as well as unknown and unexpected consequences.

Procurement and Inventory Management

Diminishing the PM regime will require changes in the supply chain that provides the personnel and materials that support the routines and meet the plant needs. New reorder levels and quantities can be set to align with the new PM strategy for consumables such as oil and grease, gaskets, gland packing, bearings, and mechanical fixings. Other key contracts must be reviewed and, in some cases, cancelled; for example, if a major overhaul of the plant is to be deferred or cancelled. Conversely, external support might be needed; for example, on-line continuous vibration monitoring that is managed by a third party.

Maintaining Performance and Continual Review

It is essential that the process of managing maintenance includes monitoring the new strategy and how it is reflected in plant performance. Indicators such as increased running defects, equipment failure rates, and forced outage rates can determine the need for review and revision of an enhanced PM strategy.

It is important to consider worsening indicators in relation to their impact on business objectives and performance. The measure must be based on the likelihood of under-performing against the objectives, and failure rates should be analyzed as individual events and a collective chain of events to predict and preempt poor performance and take corrective action through the PM strategy.

If failure rates do not increase, it might be possible to again extend the interval between PM activities, thus reducing expenditure further. As the retirement date approaches, there will be an increasing amount of PM activity that will not contribute to any aspect of performance, and it should be systematically removed.

The cycle of "plan, do, assess, review" must be maintained through the last phase of asset life to ensure that the plant is operated safely and reliably and to derive the best value for the company.

Section 5: Safety and Environmental Impacts

Compliance

HSE compliance becomes essential in the retirement phase. First, a major incident could induce the owner to bring forward plant closure in efforts to stem potential costs. Second, the restatement of and adherence to recognized standards mitigates risks across the site as managers reiterate the performance and expectations. Behavioral safety is particularly relevant in ensuring that the mindset on site does not relax.

Housekeeping, for example, can be used as a leading indicator of compliance. In addition to minimizing the risk of a safety or environmental incident, a clean and tidy site sends a message and establishes a culture of care and pride in the job for those working in all areas of the plant.

Health and Safety Performance

For assets due for retirement, safety must remain the number one priority. At a time when budgets are being cut, the plant manager must ensure that there is no compromise on safety. Although the decision-making process might change and more commercial risk might be considered, there can be no half measures or shortcuts taken with safety. Failure in the area of safety will have far-reaching effects across the business, impacting people, plant, and profits.

Safety is the priority and the plant manager must continually emphasize the point, reiterating that a plant managed well for safety is managed well for business. There can be no conflict between safety and commercial responsibilities. The clarity of arrangements required to maintain safety standards on site must be replicated in the commercial arena, and the linkage should be made wherever possible—such as when determining contract terms and conditions, operational parameters, and inspection regimes.

A safety assessment is included in all FFS assessments to ensure that a change in PM frequency or removal of a PM has no adverse effects on safety. In some cases in which plant investment has been cancelled that might increase the risk of a component failure, additional condition monitoring inspection might be required. The frequency of inspections should be selected to minimize the risk of failure between inspections.

PM routines for the calibration of safety equipment or the testing of safety-critical systems must be maintained, along with statutory requirements for inspection of pressure systems.

Managers must pay attention to the following aspects of safety to reduce the risk to people, plant and profits:

- **Behavioral.** Beliefs, attitudes, and behavior.
- **Asset.** Maintenance of plant integrity to provide a safe working environment.
- **Functional.** Securing safe plant operations and methods of work.

Section 4 described how the critical success factors of the business shape the PM strategy and how the HSE business aspects are a significant element of the critical success factors. More specifically, Table 4-2 listed typical systems, plant, and equipment that belong to the family of statutory compliance PM.

The derivation of appropriate operations and maintenance strategies for the plant and equipment are directly affected by the need to achieve statutory compliance and ensure that the asset maintains its operating license to extract maximum asset value during the retirement period.

Environmental Performance

The asset's environmental impact statement and risk assessments document the site activities that are most likely to impact the environment. The information in this section is the starting point to ensure that compliance is achieved.

All emissions to air, water, and land will be controlled and monitored by equipment that requires routine maintenance. The failure of this equipment (or the process associated with this equipment) can result in noncompliant operation. Table 5-1 lists the major components of typical environmental protection systems. The emission points and associated devices should ideally undergo a criticality review for the derivation of a new strategy. If this is not possible, the review processes illustrated in Figures 4-3, 4-4, 4-6, and 4-8 should be used.

Table 5-1
Typical environmental protection systems

Point of Impact and Emission	Devices	Automatic Detection	Secondary Control Action
Air Sulfur dioxide, carbon monoxide, carbon dioxide, nitrogen oxides, and particulates	Selective catalytic reduction, selective noncatalytic reduction, flue gas desulfurization, precipitators	Maximum continuous rating alarm and equipment trip	Procedures Internal audit
Water Oil, pH, volatile organic compounds	Oil separators, neutralizing tanks, pits and pumps, bunds and drains	Maximum continuous rating alarm and equipment trip	Procedures Internal audit
Land Oil, chemicals	Drains, bunds, storage	None	Procedures Internal audit

Section 6: Finance and Other Impacts

Market-Driven Operating Regime Changes

Power plants operate under differing commercial arrangements, but those exposed to a liberalized market have already seen significant changes. Plant life is no longer determined by technical issues of plant integrity but increasingly by commercial imperatives.

Plants that are party to long-term power and fuel purchase agreements can be sheltered from external competition for longer. However, a merchant plant operates within a free market and, at the extreme, earns its income solely from trading its generation in the short-term spot market. To protect it from fluctuations in price, it enters into contracts with varying degrees of complexity, seeking to mitigate risk and enhance earnings.

In general, the decision to generate is made when the potential income exceeds the short run marginal cost of generation—primarily the fuel component. A power plant becomes more marginal as its thermal efficiency, fuel cost, or plant flexibility deteriorates relative to the competition. Operating regimes will move away from high-capacity factors toward two-shift operation.

The owner must decide whether to retain assets capable of high-capacity factors or to accept the change and position the plant accordingly.

To generate cash and earn, at a minimum, a contribution toward the fixed cost base, the plant will target the peaks and shoulders of the demand curve, where it can maximize the earnings for its given cost of generation. In addition the acceptable level of threat to availability increases, and risk-based decisions can be made using a range of techniques to establish the appropriate maintenance and operation regimes.

For plants moving toward the margin and under notice of retirement, the critical success factor moves from availability toward reliability—that is, being available when required (income exceeds marginal cost). Targets are based more on commercial availability and measures that indicate reliability, such as failed starts, failure to meet notice to synchronization times, and deviations from nominated profiles.

Changes to operating regimes mean that flexibility and reliability become the key attributes. Managers can take the opportunity to revisit many existing arrangements in relation to maintenance support, service provision, and staff work patterns challenging the fixed cost base and considering arrangements such as supplier alliances, outsourcing, and shared service arrangements.

Supporting Operations

All business functions should be seen to support operations and the focus on meeting customer requirements to drive value (see Figure 6-1).

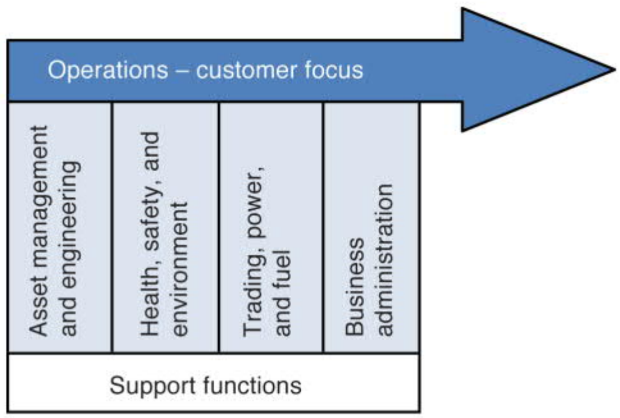

Figure 6-1
All functions support operations

Maintenance regimes are aligned to the operational requirements, and there can be opportunities to undertake work at low price periods. For those plants operating within a fleet, the risk of breakdown can be mitigated in part by its colleagues providing replacement generation. Some fleet players will instigate a process of internal transfer pricing to reflect the commerciality of that event to incentivize plant staff to deliver reliability. However for independent plants, the position is less comfortable, and real cash is lost.

Risk Process and What-If Scenarios

Experience indicates that although a plant can be designated for retirement, the end date often proves flexible. Plants might have to operate under these conditions of uncertainty for prolonged periods before the formal notice of closure is issued to staff and the authorities. In these circumstances, the manager must ensure that beneficial options are not ruled out for the final operational phase of the plant and the post-closure options for the site.

The operational phase might actually require a more arduous regime over a prolonged period as the company takes value from the plant. Experience shows that with minimal investment, careful management, and avoidance of major breakdowns, operating lives can be extended well beyond that initially anticipated.

After closure, there is value to be won or lost. The following options should remain viable until they are definitely not required:

- Sell operational site
- Replant or repower the asset
- Transfer or sell key components (lift-and-shift option)
- Demolish and scrap to minimum standard required
- Remediate site to greenfield status

People and Culture

Plan for Change

There will be a need for an analytical plan of actions and resource requirements translated into financial terms within operational budgets, but first, there should be a plan for change. This is fundamentally different in nature, less formulaic, and aimed at bringing about a more flexible and adaptive approach that becomes embedded in the culture of the power plant and can be seen in the actions of all those involved. If *culture* is described as "what happens when nobody is watching," this is likely to be a significant step; it cannot be underestimated, sidelined, or ignored.

People's thinking can be influenced by providing them with analysis showing that change is required. However, they will actually respond to a vision that helps them see and feel the reality of the need for change. The implication is that the manager must become a leader who actively tells the story, initiates (but not necessarily leads) the process, and demonstrates the new behaviors needed to implement change. The appeal is not to the head but to the heart.

An eight-stage approach to successful change [5] has been used in many instances, including power plants (see Figure 6-2).

Action	Behavior
Urgency	• People talk about need for change
Guiding team	• Powerful team built and working
Vision	• Team builds the vision for change
Buy in	• Behaviors start to change
Empower	• People feel able to act on vision
Early wins	• Vision seen as being fulfilled
Do not let up	• More and more changes are seen
Make it stick	• Winning behavior continues

Figure 6-2
An eight-stage approach to successful change

The eight stages are described as follows:

1. **Increase urgency.** Power plant cultures tend to be inherently conservative and often, with experienced staff, complacency must be overcome. Identified opinion formers (not just managers and supervisors) should be targeted with tangible, practical examples of the need for change and, particularly, with examples from others that show how it contrasts to the outside world. Do not diminish the urgency by producing the more formal management vision statements and strategy.

   Action: Show why there must be change, addressing the "what is in it for me?" question that shows staff the benefits and the consequences of the status quo.

2. **Build a guiding team.** The team will consist of the right people who see the opportunity to make things different and who are drawn into the process showing enthusiasm and commitment. It need not and will not be the management team and staff representatives but will take a slice across the business at different levels. The group cannot avoid confronting situations of complacency and incompetence, and the first priority is to establish trust between the members who might not have worked with each other in the past or be accustomed to this type of arrangement.

   Action: Identify the right people, support the team, and guide the process, as there will be confrontation—at times, with senior staff.

3. **Get the vision right.** This is not about planning process or budgeting detail but about "painting a picture" and "telling the story." This more subjective approach requires a different mindset than that generally seen within an organization that traditionally focuses on engineering, numbers, and system controls. The visions must be simple and able to be communicated quickly and coherently to everyone. There is no requirement for detailed budgets or over-analysis, but there must be a clear high-level plan showing how quickly the changes are to be introduced.

   Action: Encourage development of a vision in simple terms that everyone can understand and relate to.

4. **Communicate for buy-in.** The vision must be shared and not just relayed down. It should be accessible for everyone. This requires an active process in which staff are engaged with the picture and story, and the presenter must be able to respond credibly to the inevitable questions and challenges. It is essential that the message is not delivered cold, and the feelings of the staff should be understood beforehand to ensure that the presentation addresses their concerns. Consistent messages must be delivered, but personalized by the presenter to make it relevant for that audience. Similarly, standard supporting information and questions and answer briefings should be available to ensure that responses are quick, pertinent, and consistent.

   People hear the words, but communication requires that they listen and understand the material. Checking that understanding by talking with staff informally in their workplace some days afterward allows the guiding team to confirm reaction, follow up on issues, and establish the perhaps novel practice of being seen to ask, listen to, and act on staff views.

   When the vision is out, those involved must act accordingly. It is easy to engender cynicism by being seen to not "walk the talk."

   Action: Demonstrate personal buy-in to the vision by ensuring personal adherence to the new way and making opportunities to talk about it with anyone in the workforce.

5. **Empower action.** This does not entail simply giving staff new roles and authorities; it is more about removing barriers to change. In some cases, it can be accomplished by providing better information that identifies the need and route for change in their area, by providing feedback to people on their performance and actions from someone other than their usual line manager, or even by changing the approach of the constraining supervisor who might be personally feeling threatened by the change.

   Action: Facilitate the process by encouraging (or sanctioning, if necessary) the removal of barriers.

6. **Create short-term wins.** On the principle that success breeds success, it is essential that early wins are publicized to build a momentum, both to reassure and encourage those making the efforts and to show those who are more resistant that change is already bringing results. Create opportunities to actively talk about these visible, meaningful, and clear results with staff without waiting for formal occasions. Early wins are often inexpensive and easily produced, but they are significant in their impact in demonstrating that change is underway. There is no virtue in waiting for the big win.

   Action: Recognize and be seen to recognize the short-term wins to encourage the next series of more significant challenges.

7. **Do not let up.** It is tempting to be convinced that the early wins demonstrate the success required, but they are merely the beginning. As the process develops, it is essential that the plant manager maintains the urgency to encourage further change and to tackle the bigger challenges that constrain the organization. As this stage progresses, systems are reviewed, and bureaucracy and politics are challenged as part of the process of implementing new and better ways of working.

   Action: Refresh the need for urgency and encourage the challenge within the organization. Managers must be able to make connections between the different areas and activities that together show that wholesale change is underway in the business and that staff input is making the difference.

8. **Make it stick.** For the change to be sustained, there must be a cultural shift, or the organization will drift back to where it was. The new way of doing things must be recognized, accepted, subjected to peer review, and must become systematic. One method is to reward and recruit those behaviors that epitomize the culture change so that they become the norm. Significantly, the culture is established toward the end of the change process when the new way of working is seen to succeed and the norm is recognized and systematically applied.

   Action: Ensure that documented systems are updated and that the new culture is rewarded. The new way of working is maintained, and the culture change continues.

Section 7: References

1. *Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the Limitation of Emissions of Certain Pollutants into the Air from Large Combustion Plants*. Available from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2001:309:0001:0001:EN:PDF.

2. *Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on Industrial Emissions (Integrated Pollution Prevention and Control)*. Available from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010: 334:0017:0119:EN:PDF.

3. *Continued Operation of 'Opted-Out' Large Combustion Plants Under the IED*. Parsons Brinckerhoff, West Yorkshire, UK. 2011.

4. *Future Prospects for Large Combustion Plants*. Parsons Brinckerhoff, Newcastle-Upon-Tyne, UK. 2011.

5. John P. Kotter and Dan S. Cohen. *The Heart of Change*. Harvard Business School Press, Boston, MA. 2002.

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BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	)	
ENTERGY NEW ORLEANS, LLC	)	
FOR A CHANGE IN ELECTRIC AND	)	
GAS RATES PURSUANT TO COUNCIL	)	**DOCKET NO. UD-18-07**
RESOLUTIONS R-15-194 AND R-17-504	)	
AND FOR RELATED RELIEF	)	

REBUTTAL TESTIMONY

OF

RORY L. ROBERTS

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

PUBLIC VERSION

MARCH 2019

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND PURPOSE

A. Name and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rory L. Roberts. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, LLC ("ESL") as Director, Regulatory Tax Accounting.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am filing this Rebuttal Testimony on behalf of Entergy New Orleans, LLC ("ENO" or the "Company") before the Council of the City of New Orleans (the "Council").

Q4. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. A summary of my education and work experience is included as Exhibit RLR-1.

Q5. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for the Federal and State income tax reporting and tax accounting data for Entergy Corporation and its regulated subsidiaries, including ENO. This includes the preparation of tax accounting and related tax data used in making regulatory filings and the preparation and filing of tax accounting testimony.

Q6. HAVE YOU TESTIFIED BEFORE THE RETAIL REGULATORS OF ENTERGY CORPORATION'S REGULATED SUBSIDIARIES?

A. Yes. For example, I filed testimony on behalf of ENO in the 2008 Rate Case before the Council.

B. Purpose of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the income tax related recommendations from the Advisors and Crescent City Power Users Group ("CCPUG"). Their recommendations concern the Company's proposed inclusion of net operating loss ("NOL") accumulated deferred income taxes ("ADIT") related to liberalized depreciation in rate base, exclusion from rate base of the liberalized depreciation ADIT associated with the meters that will be retired as a result of the Advanced Metering Infrastructure ("AMI") project, and exclusion from rate base of ADIT subject to FASB Interpretation No. 48 ("FIN 48").

Q8. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Below is a summary of my conclusions. Instances in which I have not addressed another party's income tax-related position should not be construed as agreement with that position.

- With income tax normalization, timing differences for when items of expense and revenue are included in cost of service versus when included on the income tax return do not change the amount of income tax expense reflected in customers' rates, despite the Advisors' assertions to the contrary. Customers' rates reflect the same amount of income tax expense because the deferred income tax expense for normalized items is offset dollar for dollar by an increase or reduction in the current income tax expense.

- Proper ratemaking is to include the NOL ADIT asset related to tax depreciation in rate base because the credit ADIT for tax depreciation is included in rate base. Accelerated tax depreciation gave rise to tax deductions that created credit ADIT in Account 282 that is included in rate base. But, ENO has not utilized all of its accelerated tax depreciation deductions to produce cost-free capital, and, therefore, the unused tax depreciation deductions have also given rise to an NOL ADIT asset. As such, an offset to the credit ADIT in rate base through the inclusion of the NOL ADIT asset in rate base is necessary to measure correctly the amount of cost-free capital created. In other words, both the credit ADIT and the NOL ADIT asset must be netted together to measure the amount of cost-free capital available to ENO.
- The Internal Revenues Service ("IRS") normalization rules make it clear that the amount of a utility's NOL ADIT asset that is attributable to income tax depreciation must be included in rate base. Private letter rulings explain that the NOL ADIT asset must be included in rate base to reduce the credit ADIT by the amount for which no cost-free capital was received. To do otherwise is a normalization violation, and the penalty for ENO would be that it could no longer use accelerated tax depreciation on its income tax return, which would harm customers.

- The Advisors' proposal to credit or decrease deferred income tax expense by $9,402,024 is a normalization violation because it ignores the offsetting $9,402,024 that was included in current tax expense. The Advisors' proposal is nothing more than flow-through accounting and creates a normalization violation when applied to accelerated tax depreciation.
- The normalization rules require consistency between the inclusion of assets in rate base and the inclusion of the related ADIT liability in rate base. The Advisors' proposal to include the ADIT liability related to the stranded AMI assets in rate base while excluding the stranded AMI assets from rate base is a potential normalization violation.
- The FIN 48 amounts represent amounts associated with aggressive tax positions that the Company and its auditors expect ENO to ultimately lose and not produce cost-free capital. In fact, ENO pays interest expense on uncertain tax positions, which interest expense is not recovered from customers. Accordingly, the FIN 48 amounts should be excluded from rate base.

II. INCOME TAX NORMALIZATION

Q9. WHY DO YOU DISCUSS INCOME TAX NORMALIZATION IN GENERAL IN YOUR REBUTTAL TESTIMONY?

A. Advisors witness James M. Proctor provides a discussion of income tax normalization suggesting that income tax normalization, which the Council[1] as well as the Federal

[1] Resolution dated August 23, 1956.

Energy Regulatory Commission ("FERC")[2] requires ENO to use, is a burden to customers, when it is not.

Q10. WHAT IS INCOME TAX NORMALIZATION?

A. Income tax normalization is the calculation of the income tax expense included in cost of service using the items of income and expense included in cost of service. This results in customers paying income tax expense based on the cost to provide them service regardless of the payments made to the taxing authorities.

Q11. WHAT HAPPENS WHEN AN ITEM OF INCOME OR EXPENSE IS TREATED DIFFERENTLY ON THE INCOME TAX RETURN THAN IN COST OF SERVICE?

A. The difference is reflected as a debit or credit to deferred income tax expense and results in credit or debit ADIT.

Q12. PLEASE PROVIDE AN EXAMPLE OF INCOME TAX NORMALIZATION IN THE RATEMAKING CONTEXT.

A. Assume Utility has revenue of $1,000 and an expenditure of $800, $700 of which is included in cost of service this year. Also, assume the income tax rate is 21%. Assume in Example One that $700 of the expenditure is deductible on the income tax return in the same year it's included in cost of service. In Example Two, assume that all of the expenditure is deductible on the income tax return in a future year. In Example Three,

[2] Uniform System of Accounts, General Instruction 18.

assume all of the expenditure is deductible on the income tax return in this year. The income tax impacts would be as follows:

		Example One	Example Two	Example Three
1	Regulatory/Tax Revenues	$1,000	$1,000	$1,000
2	Regulatory expense	$700	$700	$700
3	Regulatory Pre-Tax Income (Line 1- Line 2)	$300	$300	$300
4	Tax Deduction Less/(More) Than Regulatory Expense (Timing Difference)	$0	$700	$(100)
5	Tax Return Taxable Income (Line 3 plus Line 4)	$300	$1000	$200
6	Current Income tax expense (Amount payable to IRS on current tax return) (Line 5 times 21%)	$63	$210	$42
7	Deferred Income Tax Expense (credit) (-Line 4 times 21%)	$0	$(147)	$21
8	Income tax expense included in cost of service (Line 6 + Line 7)	$63	$63	$63

Q13. IN ALL THREE EXAMPLES DOES THE CUSTOMER PAY THE SAME AMOUNT OF INCOME TAX EXPENSE?

A. Yes. Using income tax normalization results in the income tax expense included in cost of service being the same in all three examples. These examples show that timing differences for when items of expense and revenue are included in cost of service versus when included on the income tax return do not change the amount of income tax expense paid by customers in rates.

Q14. DOES MR. PROCTOR ACKNOWLEDGE THAT TIMING DIFFERENCES FOR WHEN ITEMS OF EXPENSE AND REVENUE ARE INCLUDED IN COST OF SERVICE VERSUS WHEN INCLUDED ON THE INCOME TAX RETURN DO NOT CHANGE THE AMOUNT OF INCOME TAX EXPENSE PAID BY CUSTOMERS?

A. No.

Q15. PLEASE DEFINE THE TERMS CURRENT INCOME TAX EXPENSE AND DEFERRED INCOME TAX EXPENSE AS USED IN THE ABOVE EXAMPLES.

A. Current income tax expense is the amount that should be paid to (or received from) the taxing authorities in the current period attributable to economic activity in the current period. Deferred income tax expense is the amount that should be paid to (or received from) the taxing authorities in the future attributable to economic activity in the current period.

Q16. DO YOU AGREE WITH MR. PROCTOR THAT DEFERRED INCOME TAX EXPENSE IS A NON-CASH ITEM?

A. No. I think Mr. Proctor's characterization of deferred income tax expense is misleading. Deferred income tax expense does reflect a payment of cash, but the payment will occur in the future.

Q17. WHAT IS THE AMOUNT OF ADIT CREATED IN THE EXAMPLES?

A. In Example One, no ADIT is created because the items of revenue and expense are included on the tax return in the same year. Example Two results in an ADIT asset of

$147. Example Three results in an ADIT liability of $21. The amount of ADIT is different in each of the examples, but the customer paid in rates the same amount in each of the examples.

Q18. DO YOU AGREE WITH MR. PROCTOR'S ANALOGY THAT ADIT IS LIKE A COST-FREE LOAN FROM RATEPAYERS?[3]

A. No. My examples show that the income tax expense paid by customers in normalized ratemaking does not change as the result of timing differences and the recording of deferred income taxes. Since customers pay the same amount in rates regardless of the amount of deferred income taxes, the ADIT is not like a loan from customers.

Q19. WHY WITH INCOME TAX NORMALIZATION DO CUSTOMERS PAY THE SAME AMOUNT OF INCOME TAXES REGARDLESS OF THE AMOUNT DEFERRED INCOME TAXES?

A. The customer pays the same amount because the deferred income tax expense for normalized items is offset dollar for dollar by a reduction in the current income tax expense. See Example Three, lines six and seven. The same is true for credits to deferred income tax expense. The credit on line seven of Example Two is offset by an increase in current income tax expense on line six of Example Two.

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[3] Direct Testimony of James M. Proctor, February 1, 2019, page 75 of 88, lines 1 through 9.

Q20. WHAT IS THE SOURCE OF THE ADIT?

A. Credit balance ADIT is in effect a cost-free loan from the government. It is the tax payments to the government that increase or decrease as ENO has timing differences that create ADIT and not customer payments. In Example Two, the source of the cash to pay the income taxes was ENO, not customers. Therefore, debit ADIT can be viewed as either provided by ENO or as an offset to the cost-free loan from the government.

Q21. WHAT ITEMS DO INCREASE OR DECREASE THE INCOME TAX EXPENSE PAID BY CUSTOMERS?

A. The items that affect the amount of income tax expense paid by customers in the computation of revenue requirement are the equity return on investment, permanent items, flow-through income tax accounting, net-of-tax accounting, and changes in income tax rates.

III. NOL ADIT IN RATE BASE

Q22. WHAT IS NOL ADIT?

A. When a company has more income tax deductions than taxable income, the excess of the income tax deductions over taxable income is called a net operating loss (NOL). Because the company has received no income tax benefit for the deductions giving rise to the NOL, the company is allowed to deduct the NOL on future income tax returns. On ENO's books the NOL is recorded as an asset in the ADIT accounts.

Q23. IS THE NORMALIZED INCOME TAX ACCOUNTING FOR NOL ADIT ANY DIFFERENT FROM EXAMPLE TWO?

A. No. The recording of the NOL ADIT does not affect the amount of income tax expense paid by customers.

Q24. IS ENO INCLUDING ALL OF THE NOL ADIT IN RATE BASE?

A. No. ENO is only including the NOL ADIT attributable to accelerated income tax depreciation in rate base.

Q25. WHY SHOULD NOL ADIT RELATED TO TAX DEPRECIATION BE INCLUDED IN RATE BASE?

A. First it is proper ratemaking; second, to not do so is a normalization violation.

Q26. PLEASE EXPLAIN WHY IT IS PROPER RATEMAKING TO INCLUDE IN RATE BASE THE NOL ADIT ASSET RELATED TO TAX DEPRECIATION.

A. Accelerated tax depreciation gave rise to tax deductions that created credit ADIT in Account 282 that is included in rate base. ENO has not utilized all of its accelerated tax depreciation deductions. Therefore, a portion of ENO's tax depreciation has also given rise to an NOL ADIT asset. Proper rate making is to include the NOL ADIT asset related to tax depreciation in rate base because the credit ADIT for tax depreciation is included in rate base. Stated another way, credit ADIT is included as an offset to rate base because ENO has been able to delay the payment for taxes through accelerated tax depreciation deductions. But, when ENO is in a net operating loss position, no cost-free capital is created because there were no tax payments to delay. As such, an offset to the credit ADIT in rate base through the inclusion of the NOL ADIT asset in rate base is necessary to measure correctly the amount of cost-free capital created. In other words, both the credit ADIT and the NOL ADIT asset must be netted together to measure the amount of cost-free capital available to ENO.

Q27. DO YOU AGREE WITH MR. PROCTOR THAT THE NOL ADIT ASSET BALANCE SHOULD NOT BE INCLUDED IN RATE BASE BECAUSE IT IS A NON-CASH EVENT?

A. No. Mr. Proctor fails to recognize that the NOL ADIT asset balance attributable to accelerated tax depreciation deductions measures the amount of credit ADIT that has not produced cost-free capital.

Q28. PLEASE EXPLAIN THE BASIS FOR YOUR OPINION THAT EXCLUDING THE NOL ADIT ASSET RELATED TO TAX DEPRECIATION WOULD VIOLATE THE INCOME TAX NORMALIZATION RULES.

A. Internal Revenue Code Section Regulation Section 1.167(1)-1(h)(1)(iii) makes it clear that the amount of a utility's NOL ADIT asset that is attributable to income tax depreciation must be included in rate base. Attached as Exhibit RLR-2 are two IRS private letter rulings, PLR Nos. 201438003 and PLR 201548017, that explain in detail the income tax normalization rules that require the inclusion in rate base of NOL ADIT attributable to accelerated tax depreciation. Those private letter rulings explain that the NOL ADIT asset must be included in rate base to reduce the credit ADIT by the amount for which no cost-free capital was received. To do otherwise is a normalization violation because credit ADIT attributable to accelerated tax depreciation deductions would offset rate base for which no cost-free capital was received.

Q29. WERE THESE PRIVATE LETTER RULINGS PROVIDED TO THE ADVISORS IN DISCOVERY?

A. Yes. The Company provided the private letter rulings to the Advisors in response to Advisors 1-31.

Q30. WHAT IS THE CONSEQUENCE OF A VIOLATION OF THE INCOME TAX NORMALIZATION RULES?

A. As I explained earlier, the penalty for ENO would be that it could no longer use accelerated tax depreciation on its income tax return. This would result in significantly lower ADIT balances at ENO and an increase in costs to customers because of the resulting increase in rate base.

Q31. DOES MR. PROCTOR OR OTHER ADVISORS WITNESSES ADDRESS THE PRIVATE LETTER RULINGS SUPPLIED IN DISCOVERY?

A. No, they do not.

Q32. WHAT DOES MR. PROCTOR RECOMMEND IF THE NOL ADIT ATTRIBUTABLE TO TAX DEPRECIATION IS INCLUDED IN RATE BASE?

A. Mr. Proctor recommends a decrease in deferred income tax expense by the amount of the NOL ADIT.

Q33. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. The Company does not. First, this proposed adjustment represents a departure from the Council's longstanding practice of normalizing income taxes for ratemaking purposes. Second, it is a potential normalization violation.

Q34. HOW DOES THE PROPOSAL DEPART FROM NORMALIZING INCOME TAXES FOR RATEMAKING PURPOSES?

A. As I showed in my examples above, the creation of an ADIT asset or liability does not affect the amount of income tax expense paid by customers in rates. Therefore, Mr. Proctor's recommendation is inappropriate and unsupportable.

When the ADIT liability balance for accelerated tax depreciation deductions was recorded, the debit to deferred income tax expense was offset by a credit in current income tax expense. There was no increase to cost of service. See Example Three for an illustration of how normalizing income taxes for ratemaking works for this item. The Advisor's proposal to remove the debit to deferred tax expense without removing the offsetting credit amount in current income tax expense is a departure from normalizing income tax expense in ratemaking.

Likewise, the Advisor's proposal does not follow with the concept of the inclusion of deferred taxes in rate base. As I explained earlier, the NOL ADIT represents accelerated tax depreciation deductions for which no cost-free capital has yet to be received. The only issue before the Council is whether ENO's rate base is appropriately stated with or without the NOL ADIT.

Q35. WHEN SHOULD RATE BASE BE CALCULATED WITHOUT THE NOL ADIT?

A. In the future when the Company uses the NOL, the NOL ADIT will be reversed on the Company's books because the Company will have received cost-free capital from its accelerated tax depreciation deductions. At that time, the customers will benefit from a reduced rate base due to the associated ADIT liability.

Q36. IN YOUR OPINION IS THE ADVISOR'S PROPOSAL TO CREDIT DEFERRED TAX EXPENSE BY THE $9,402,024 A NORMALIZATION VIOLATION?

A. Yes. The normalization rules require consistency between tax expense, depreciation expense, ADIT, and rate base.[4] The Advisors' proposal to credit or decrease deferred income tax expense by $9,402,024 is a normalization violation because it ignores the offsetting $9,402,024 that was included in current tax expense.[5] The Advisors proposal is nothing more than flow-through accounting. Flow-through accounting creates a normalization violation when applied to accelerated tax depreciation.

[4] Internal Revenue Code §168(i)(9)(B).

[5] See Example Three.

IV. ADIT FOR STRANDED AMI ASSETS

Q37. DO YOU AGREE WITH ADVISORS WITNESS BYRON S. WATSON'S RECOMMENDATION TO INCLUDE IN RATE BASE THE ADIT FOR AMI STRANDED PLANT EVEN THOUGH THE AMI STRANDED PLANT IS NOT IN RATE BASE?

A. No. The ADIT liability for stranded AMI assets, such as meters, is primarily related to accelerated tax depreciation deductions. This ADIT liability is subject to the income tax normalization rules, which I discussed earlier in my testimony. The normalization rules require consistency between the inclusion of these assets or the corresponding regulatory asset in rate base and the inclusion of the related ADIT liability in rate base. In my opinion, Mr. Watson's proposal to include the ADIT liability related to the stranded AMI assets in rate base while excluding the stranded AMI assets or corresponding regulatory asset from rate base is a potential normalization violation.

Q38. COULD A NORMALIZATION VIOLATION FOR JUST A FEW OF ENO'S REGULATED ASSETS RESULT IN THE LOSS OF ACCELERATED TAX DEPRECIATION FOR ALL OF ENO'S ASSETS?

A. Yes. A utility that does not comply with the normalization rules loses the ability to claim accelerated tax depreciation on its income tax return. The penalty for not complying with the normalization rules is severe. The loss of accelerated tax depreciation affects all future tax depreciation of the utility, not just the tax depreciation for the assets with the normalization violation.

Q39. DO YOU AGREE WITH MR. WATSON THAT ENO HAS COST-FREE CAPITAL FROM THE ADIT RELATED TO THE STRANDED AMI ASSETS?

A. Yes. However, Mr. Watson ignores that ENO also has a capital cost related to the stranded AMI assets that is even greater than the cost-free capital represented by the related ADIT liability. The correct treatment for this ADIT liability is to exclude it from rate base because the related stranded AMI asset or corresponding regulatory asset is excluded from rate base. To do otherwise is a potential normalization violation. As explained by ENO witness Joshua B. Thomas, this required treatment informed the Company's interpretation of the Agreement in Principle in Docket No. UD-16-04.

V. FIN 48 ADIT

Q40. WHAT IS FIN 48?

A. FIN 48 is a financial accounting pronouncement that establishes rules for identifying uncertain tax positions taken by tax payers, measuring the portion of tax deduction benefits that are likely to be forfeited, and reflecting that fact on their financial statements. An uncertain tax position occurs when a tax payer takes an aggressive tax deduction on its tax return to lower its tax liability. FIN 48 is now incorporated in ASC 740-10.

Q41. HOW IS FIN 48 IMPLICATED IN THIS PROCEEDING?

A. ENO has removed from its rate base the portion of various ADIT liabilities that is unlikely to produce cost-free capital due to the aggressive tax position taken by ENO in its filings with Federal and State tax authorities. The Company and its auditors have determined that those tax deductions are so unlikely to be realized that they must be disclosed for financial reporting. Historically, the Company has generally not prevailed on tax benefits subject to the reporting requirements of FIN 48.

Moreover, ENO has consistently removed these amounts subject to FIN 48 from rate base in past rate cases and formula rate plan proceedings. The Advisors and CCPUG, however, do not agree with their removal from rate base.

Q42. WHY DOES THE COMPANY TAKE AGGRESSIVE TAX POSITIONS?

A. Because both customers and the company can benefit from savings on taxes. Although the customer does not receive the immediate benefit of the full aggressive tax deduction due to the exclusion of amounts from rate base, the customer does receive the immediate benefit in rate base of the portion of the aggressive tax position in excess of the FIN 48 portion, that is, the portion that is likely to produce cost-free capital.

Q43. [redacted]

A. [redacted]

Q44. HOW DO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES REQUIRE THE COMPANY TO RECORD UNCERTAIN TAX LIABILITY AMOUNTS?

A. Generally Accepted Accounting Principles require that the "likely" portion of the aggressive tax position be recorded as a deferred tax liability. Generally Accepted Accounting Principles require the remaining "unlikely" portion of the federal tax benefit to be recorded as a liability. However, in May of 2007, the FERC issued its pronouncement requiring that the "unlikely" portion of the aggressive tax position also be recorded in a deferred tax account. Thus, the Company records both the "likely" and the "unlikely" portions in deferred tax accounts.

Q45. WHAT DOES THE FEDERAL TAX LIABILITY ASSOCIATED WITH AGGRESSIVE TAX POSITIONS AT TEST YEAR END REPRESENT?

A. The FIN 48 amounts represent amounts associated with aggressive tax positions that the Company and its auditors expect ENO to ultimately lose. This means that ENO and its auditors expect ENO to pay the FIN 48 amounts to the Federal and State taxing authorities with interest. As a result, these amounts do not represent cost-free capital to the Company

Q46. WHY IS THE QUESTION OF WHETHER THE ITEMS AT ISSUE WILL RESULT IN COST-FREE CAPITAL TO THE COMPANY IMPORTANT?

A. The question is important because ADIT liabilities that are not expected to produce cost-free capital should not be included in the calculation of ENO's rate base.

Q47. HAS THE COMPANY ACCRUED INTEREST ON ITS UNCERTAIN TAX POSITIONS?

A. Yes, the Company has accrued interest on uncertain tax positions in FERC Account 237191.

Q48. DOES THE COMPANY PAY INTEREST ON TAX UNDERPAYMENTS ASSOCIATED WITH UNCERTAIN TAX POSITIONS THAT IT DOES NOT PREVAIL ON?

A. Yes, the Company will have to pay interest on all amounts of tax underpayments paid to the federal government.

Q49. HAVE THESE INTEREST AMOUNTS BEEN INCLUDED IN THE COST OF SERVICE STUDIES TO BE RECOVERED FROM CUSTOMERS?

A. No, they have not been included.

Q50. DOES MR. PROCTOR ACKNOWLEDGE THAT ENO PAYS INTEREST ON TAX UNDERPAYMENTS ASSOCIATED WITH UNCERTAIN TAX POSITIONS AND DOES NOT RECOVER SUCH INTEREST EXPENSE FROM CUSTOMERS?

A. No. He claims that the aggressive tax positions produce cost-free capital when, in fact, they do not.

Q51. WHAT IS THE BEST WAY TO ENCOURAGE THE COMPANY TO TAKE UNCERTAIN TAX POSITIONS?

A. The best way to encourage the company to take aggressive tax positions is to treat the Company fairly in the regulatory process by not including FIN 48 liabilities as an offset to rate base as if they did produce cost-free capital, when indeed they did not.

Q52. MR. KOLLEN ARGUES THAT IF CUSTOMERS BEAR THE INTEREST EXPENSE ASSOCIATED WITH UNCERTAIN TAX POSITIONS, THEN THE FIN 48 AMOUNTS SHOULD BE INCLUDED IN RATE BASE. DO YOU AGREE?

A. No, that would not be fair. No one expects the aggressive tax positions to produce cost-free capital.

Q53. [redacted]

A. [redacted]

Q54. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

RORY L. ROBERTS,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

RORY L. ROBERTS

Sworn to and

Subscribed Before Me

This 18 Day of March, 2019.

NOTARY PUBLIC
Edward R. Wicker, Jr., LA# 27138
Commission expires at death

Rory L. Roberts
Educational Background and Professional Experience

Education

Southwest Baptist University September, 1979 to May, 1983
Bolivar, Mo. 65613

BS, Majors in Accounting and Business Administration

Summa Cum Laude

3rd in class of 194

Certified Public Accountant
Awarded Gold Medal for achieving the highest score of Missouri candidates on the November 1983 Uniform CPA Examination.

Elijah Watt Sells Award from the American Institute of CPAs in "recognition of performance with high distinction in submitting papers of outstanding merit for the Uniform CPA examination November 1983". The award was given to 117 candidates out of the 72,695 taking this exam.

Professional Affiliations
American Institute of Certified Public Accountants

Arkansas Society of Certified Public Accountants

Professional Experience
Entergy Services, Inc. February, 1993 to Present

New Orleans, LA

Director, Regulatory Tax Accounting	2014 – Present
Director, Income Tax	September 2008 – 2013
Director, Income Tax Accounting and Compliance	March 2003 – August 2008
Manager, Domestic Income Tax	2000 to 2003
Tax Advisor	1998 to 2000
Senior Staff Tax Analyst	1997 to 1998
Senior Lead Tax Accountant	1993 to 1997

Arkansas Power & Light Company October, 1987 to January, 1993

Little Rock, AR

Progressed from Staff Accountant II to Senior Accountant while working in Taxes & Special Studies and in Regulatory Accounting & Taxes.

Charles Cole Co., CPAs March, 1984 to October, 1987

North Little Rock, AR

Progressed from staff to supervisory level while performing duties in audit, tax and management advisory services.

ENTERGY NEW ORLEANS, LLC.
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the First Set of Data Requests
of Requesting Party: Advisors to the Council
of the City of New Orleans

Question No.: Advisors 1-31 Part No.: Addendum:

Question:

Please refer to the Revised Direct Testimony of Joshua B. Thomas, the answer to Question Q99 at page 73, which says “This ratemaking approach is required by the IRS in order to comply with tax normalization rules.” Please provide a copy of each IRS rule and a copy of each PLR related to this statement.

Response:

Please see the attached.

Private Letter Rulings

Private Letter Ruling 201438003, 09/19/2014, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: 201438003

Release Date: 9/19/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-104157-14

Date:

June 12, 2014

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 24, 2014, and additional submission dated May 19, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying electricity in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A and Commission B with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year C. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year D.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission A, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission A further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission A also held that to the extent tax normalization rules require recording the NOL to rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission A is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account

balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201548017, 11/27/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryforward-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated natural gas distributor's rate base by balance of its ADIT accounts unreduced by its NOLC-related deferred tax account, by full amount of its ADIT account balances offset by portion of NOLC-related account balances, or any reduction in taxpayer's tax expense element of cost of service to reflect tax benefit of its NOLC would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: 201548017

Release Date: 11/27/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-116998-15

Date:

August 19, 2015

LEGEND:

Taxpayer =

Parent =

State A =

State B =

Commission =

Year A =

Year B =

Date A =

Date B =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated May 14, 2015, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is primarily engaged in the regulated distribution of natural gas in State A. It is incorporated in State B and is wholly owned by Parent. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer incurred net operating losses (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "last dollars deducted" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission offsets rate base by Taxpayer's ADIT balance. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT. One proposal made to Commission was, if Commission allowed Taxpayer to reduce the ADIT balance as Taxpayer proposed, then an offsetting reduction should be made to Taxpayer's income tax expense element of service.

A Utility Law Judge upheld Taxpayer's position with respect to the NOLC-related ADIT and ordered Taxpayer to seek a ruling from the Internal Revenue Service on this matter. This request is in response to that order.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the balance of its ADIT accounts unreduced by its NOLC-related deferred tax account would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.
3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the proposed order by the Utility Law Judge upholding Taxpayer's position that the NOLC-related deferred tax account must be included in the calculation of Taxpayer's ADIT is in accord with the normalization requirements. The "last dollars deducted" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "last dollars deducted" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, reduction of Taxpayer's tax expense element of cost of service, we believe that such reduction would, in effect, flow through the tax benefits of accelerated depreciation deductions through to rate payers even though the Taxpayer has not yet realized such benefits. In addition, such adjustment would be made specifically to mitigate the effect of the normalization rules in the calculation of Taxpayer's NOLC-related ADIT. In general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. See generally, § 1.46-6(b)(2)(ii) (In determining whether, or to what extent, the investment tax credit has been used to reduce cost of service, reference shall be made to any accounting treatment that affects cost of service); Rev. Proc 88-12, 1988-1 C.B. 637, 638 (It is a violation of the normalization rules for taxpayers to adopt any accounting treatment that, directly or indirectly flows excess tax reserves to ratepayers prior to the time that the amounts in the vintage accounts reverse). This "offsetting reduction" would violate the normalization provisions.

Based on the representations submitted by Taxpayer, we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the balance of its ADIT accounts unreduced by its NOLC-related deferred tax account would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.
3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTIONS R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

REBUTTAL TESTIMONY

OF

KENNETH F. GALLAGHER

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME.

A. My name is Kenneth F. Gallagher.

Q2. ARE YOU THE SAME KENNETH F. GALLAGHER WHO PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony before the Council of the City of New Orleans ("the Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Crescent City Power Users' Group ("CCPUG") witness Lane Kollen has taken issue with the lead-lag analysis that I performed to support the ENO cash working capital adjustment proposed in this proceeding. Specifically, Mr. Kollen has proposed that the lead-lag analysis be adjusted to reflect a payment lag associated with payment of common dividends. My rebuttal testimony, which is set out below, rebuts the appropriateness of that adjustment in several respects. It should be pointed out that in making this recommendation Mr. Kollen has lowered the cash working capital requirement and reduced both the electric and gas rate bases in this case. As will be discussed, both Mr. Kollen's rationale and methodology are conceptually erroneous and improperly hypothetical and therefore should be rejected.

III. RESPONSE TO MR. KOLLEN'S ARGUMENTS

Q5. WHY IS MR. KOLLEN'S RECOMMENDED ADJUSTMENT TO THE LEAD-LAG STUDY CONCEPTUALLY ERRONEOUS?

A. As discussed in my Revised Direct Testimony, the lead-lag analysis in this case was performed pursuant to Section 158-133 B (12) of the Code of the City of New Orleans ("New Orleans City Code") which requires that a lead-lag analysis be used for cash working capital purposes. In the alternative if a lead-lag analysis is not performed, an analysis of Operations and Maintenance ("O&M") expense net of fuel on a 45-day lag basis is to be utilized. Consequently, as a result of both prior practice and Council rule, it is ENO's O&M expenses that are the subject of the cash working capital analysis for ratemaking purposes. Such an analysis does not include common dividend payments as contended by Mr. Kollen primarily due to the fact that such dividends, if paid, are not O&M expenses. Despite agreeing with the concept that ENO operating expense data should be used[1] in a Cash Working Capital ("CWC") analysis, Mr. Kollen testifies that "imputed" common dividends from the Entergy parent[2] should be used in the ENO CWC analysis. I disagree.

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[1] *See* Excerpts of the deposition of Lane Kollen in Docket UD-18-07 taken March 15, 2019 attached hereto as Exhibit KFG-3, Tr. p. 32 lines 22 -25; *see id.* at p. 33 lines 1-5.

[2] *Id.* at p. 35 line 21.

It should be noted that as a matter of straight forward Federal Energy Regulatory Commission ("FERC") utility accounting, common dividends are not and never have been considered or recorded as O&M expenses in the books of ENO or any other company. Rather, common dividends, when declared and paid, are recorded as a balance sheet item "Dividends Declared" (A/C 238/438) and paid out of retained earnings on the balance sheet. As a balance sheet item, common dividend payments cannot in any way be considered O&M expenses.

From strictly an accounting perspective, common dividends are more properly considered as a component of the investor's return on equity ("ROE") which as Mr. Kollen agrees is not an expense.[3] Yet, he nonetheless, considers the common dividend to be an "expense" and therefore to be considered in the lead-lag analysis. By any reasonable accounting definition, common dividends clearly are not part of utility operations and there for do not meet the requirements of Section 158-133 B (12) of the New Orleans City Code.

In addition, because the timing of the payment common dividends are frequently implicitly included as a component in the determination of the investors required ROE, the dividend component of the ROE should not be utilized again as an improper adjustment to rate base via a payment lag as if they are operating expenses. This would be contrary to the CWC rules established by the Council. Such treatment would be an improper double-count of common dividends in the ENO cost of service.

[3] *Id.* at p. 40 lines 9-25; p. 41 lines 1-18.

Q6. HOW IS SUCH TREATMENT OF COMMON DIVIDENDS IN THE LEAD-LAG ANALYSIS A DOUBLE COUNT OF THE EFFECTS OF COMMON DIVIDENDS?

A. There are two points to be made in this regard. First, the utility cost of service, which is the basis for the revenue requirement and ultimately for revenues to be received by the utility, does not vary depending upon the decision to make common dividend payments to shareholders. When the ROE is established by the Council, it does so without reference to a specific cash dividend payment being made out of earnings. This is one of the reasons that the cash dividend is not an operating "expense," but rather a payment from retained earnings. Second, while many ROE models utilize the discounted cash flow ("DCF") model, they are not dependent on the timing of payment of actual cash dividends by ENO, but rather investor expectations as what future dividends may be for a group of comparable utilities. Given this, it would be inappropriate to assume that such assumptions implicate actual cash flows in the cost of service for lead-lag purposes and actual cost of service cash flows. In point of fact a reasonable ROE can be determined for a utility without any assumed cash dividend payment pattern.

Q7. HOW DOES THE ROE DETERMINATION AFFECT THE ISSUE OF A "DOUBLE COUNT"?

A. It is well known by equity market analysts that the amount and timing of the payment of common dividends is an essential input into the determination of the investors' required return on equity for certain ROE models. In the application of these ROE models, dividend payments directly affect the market price of the company's stock and therefore the cost of equity determination. Were a dividend-paying company to alter the amount or timing of common dividends, the required return on equity would be directly affected by altering the value of the company's share price and ultimately its ROE determination. Thus, the effects of the timing of common dividend payments are, in essence, already directly taken into account for ratemaking purposes via the ROE determination. In the ROE context, any cash flow benefit or detriment associated with the timing of the payments of common dividends inures to the investor as part of the return on equity compensation for an equity investment in the utility. Thus, to seek, as Mr. Kollen does in this case, a reduction in rate base for alleged cash flow "benefits" via lowering the rate base is not only improperly reducing the <u>earned</u> ROE (and the ability of the company to pay common dividends) but is also double counting cash flow lag effects already considered in determining the required ROE.

Q8. EARLIER IN YOUR TESTIMONY, YOU REFERRED TO MR. KOLLEN'S PROPOSAL AS "IMPROPERLY HYPOTHETICAL." HOW IS THAT THE CASE?

A. Mr. Kollen agrees that the CWC analysis for purposes of this proceeding should be based upon ENO-specific expense data.[4] Putting aside the fact that common dividends are not expenses, in order to quantify a common dividend payment lag adjustment for ENO, it was necessary for Mr. Kollen to create cash payment elements associated with a lag in common dividend payments for ENO that are not factual in any respect. To do this, he did not rely upon ENO data, but rather he used estimates of ENO dividend payments

[4] *Id.* at pp. 32-33.

based upon (1) imputed and not actual ENO dividend payments[5] and (2) he assumed Entergy Corporation's dividend payment practices[6] comported with ENO's practices. In so doing, Mr. Kollen utilized data that was hypothetical and unrelated to ENO's actual dividend experience.

In the first instance, Mr. Kollen imputed ENO common dividend payments rather than review actual cash payments and related timing of such payments actually made by ENO.[7] In addition, his assumptions as to quarterly common dividend payments, *i.e.*, amounts paid, declaration dates, and payment dates are premised on the historic experience of the parent company Entergy Corporation in regard to dividend payments to its shareholders and not to ENO's payments to Entergy.

In addition, it is important to realize that historically ENO has made common dividend payments to it sole stockholder, Entergy Corporation, on an irregular basis -not necessarily quarterly- and does not use the same timing process as does Entergy Corporation in regard to timing of payments, including noticing and paying its shareholders consistent with U.S. Securities and Exchange Commission ("SEC") rules. Furthermore, for 2018 and going forward, ENO is an LLC and does not pay common dividends but rather pays equity distributions. So, when Mr. Kollen establishes a common dividend payment lag for ENO in this case based upon declaration and payment date patterns premised on Entergy Corporation practices, such a pattern has nothing to do

[5] *Id.* at p. 34 lines 3-25, p. 35 lines 1-23.

[6] *Id.* at p. 35 lines 5-23.

[7] *Id.* at p. 35 line 21.

with ENO. Consequently, Mr. Kollen's methodology in regard to this common dividend payment lag proposal for ENO must be viewed as totally hypothetical, inapplicable, and therefore incorrect.

Q9. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF Louisiana

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

KENNETH F. GALLAGHER,

who after being duly sworn by me, did depose and say:

That the foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

KENNETH F. GALLAGHER

Sworn to and

Subscribed Before Me

This 19th Day of March, 2019

NOTARY PUBLIC

Lawrence J. Hand Jr.
Bar 23770 / Notary 52176
Notary Public in and for the
State of Louisiana.
My Commission is for Life.

In the Matter of:

Application of Entergy New Orleans, LLC, et al

Lane Kollen

March 15, 2019

CURREN COURT REPORTERS

504-833-3330
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BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTION R-15-194 AND R-17-504 AND FOR RELATED RELIEF	DOCKET NO. UD-18-07

* *

Deposition of LANE KOLLEN, 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075, taken at the law offices of ROEDEL PARSONS KOCH BLACHE BALHOFF & McCOLLISTER, located at 1515 Poydras Street, Suite 2330, New Orleans, Louisiana 70112, commencing at 10:02 A.M., on Friday, the 15th day of March, 2019.

APPEARANCES:

ENTERGY SERVICES, INC.
(By: Alyssa Maurice-Anderson, Esquire
- and -
Brian L. Guillot, Esquire)
(via telephone)
639 Loyola Avenue
Suite 2600
New Orleans, Louisiana 70113

- AND -

read.)

Q. All right. Okay. Are there any other elements to that calculation? Is there -- I thought it was a three-part formula, but that's just my recollection. 0.326 times capital structure times something or --

A. Yeah, I think that's right. Yeah, the line item, line 56, Common equity dividends, basically the cell C56 on that same tab in the workbook has a formula and it says, Rate base I9 times a million times cost of capital F17 times .0326. (As read.)

Q. And so --

A. So I think I could probably just, you know, describe it in laymen's terms, but --

Q. Sure.

A. But basically it's the weighted cost of the cost of equity times the rate base gives you the return on equity and then the 3.26 gives you the ratio of the cash to the rest of the rate of return. I don't remember exactly what the cells say, but that's generally the concept, to split the return on equity between the dividend and the growth.

Q. Okay.

A. The growth would not be a cash expense for cash working capital purposes, but the cash dividend would be a cash expense.

Q. So if you're splitting something, that sounds like subtraction to me, not multiplication. Can you help me understand why you're multiplying the dividend yield?

A. Yeah. What you have to do is -- you know, we calculated the weighted average cost of capital using a 9.35 percent return on equity.

Q. Right.

A. And so basically what you have to do is you have to calculate what portion of the earnings on common as a result of that 9.35 percent is a cash dividend versus a non-cash growth factor. So that's what that calculation is intended to do.

Q. Okay.

A. And then that, in turn, feeds into the cash working capital calculation with an appropriate expense lag days.

Q. All right. Did Entergy New Orleans actually pay these dividends in cash?

A. Entergy New Orleans does have a

history of paying dividends up to Entergy Corporation, but what we did is -- Let me step back a minute here.

When the rate of return experts do their analysis, like Mr. Baudino, when he did his analysis, he develops a comparable group and that comparable group is intended to be comparable to Entergy Corporation because Entergy Corporation is publicly traded. Entergy New Orleans is not. So the presumption by the rate of return expert is that the parent Company is the rate of return or the required return on equity; whereas the individual utility is the entity that has the long-term debt.

Just to make sure that we're clear where we're picking up the return on equity as opposed to the cost of long-term debt, the return on equity is always done at the parent company when there's a utility holding company. And so using the discounted cash flow methodology, the rate of return analyst develops first a dividend yield and then an expected growth and some of those do then under the discounted cash flow methodology is the required return on equity.

So that's why ENO is not in the group. Entergy is the -- basically the bogie and then you develop a group, a comparative group with similar risk characteristics. And from that, Mr. Baudino developed a dividend yield of 3.26 percent and a growth factor of whatever the difference is between that and 9.35 percent.

Q. So are you telling me that Mr. Baudino developed an ROE for Entergy Corporation and that is his recommendation for ENO is that it had Entergy Corporation's return on equity?

A. Well, that's generally the standard, yes. I mean, you have to develop a comparative group and it has to have market data. So it necessarily involves the parent companies of subsidiary utility companies necessarily.

Q. And so you're saying that Mr. Baudino didn't do anything to his recommendation to adjust it for ENO-specific factors; right?

A. You'll have to ask him that. I'm not aware that he did, but, you know, his analysis is his analysis. I'm just telling you my understanding of what he did. I didn't, you know, develop the analytical methodology for him, nor did I review the mechanics of it. I simply took the result.

Q. Do all of his methods rely upon a common dividend yield?

A. Well, there's only one. To my recollection, there's only one that has a dividend yield component and it's Mr. Baudino's primary methodology; that is, a discounted cash flow. I believe that he also uses CAPM, the capital asset pricing model, but that does not have a dividend yield component, and I believe he uses some form of risk premium.

But, in any event, this -- his recommendation to my understanding is based exclusively on the DCF, but it's informed to the extent judgment is involved by the results of the other methodologies. So most directly as a mechanical matter, it's a DCF and so that way, we can derive the dividend yield directly from his work papers and schedules.

Q. So this dividend component to cash working capital, it's different than all the other elements in the cash working capital analysis; isn't it?

A. Each line item is different for the most part.

Q. I mean, is it different in the sense of the source of the data?

A. Well, the source of the data is the Company's filing coupled with the independent analysis performed by Mr. Baudino. And the reason that it starts with the Company's filing is because you have a rate of return that is applied to rate base and so that rate base, by and large, is what is included in the Company's filing plus or minus any adjustments that we have recommended.

Q. I think I was too vague in my question.

A. I'm sorry. Was I too precise in my answer then?

MR. PARSONS:

I'm sorry I didn't object.

EXAMINATION BY MR. PERRIEN:

Q. The cash working capital analysis, that's what I'm talking about, the cash working capital, not the ROE, isn't it based on

Q. Okay. You sort of switched focus to dividend yield. And, again, I was sort of focused on the lags, the timing. I'm not worried about the amount. I'm worried about the lags. Why didn't you use the ENO lags?

A. Well, because I had to use something that was consistent with the derivation of the return on equity. And Entergy New Orleans' dividends will vary over time, depending upon whatever its cash needs are. In other words, Entergy Corporation manages ENO's capital structure and so if Entergy New Orleans needs more cash, Entergy Corporation infuses that cash as an equity investment into Entergy New Orleans. If Entergy New Orleans has more cash than what it needs, it can push that up to Entergy Corporation in the form of dividends. But I didn't even look at the pattern of dividends from ENO to Entergy Corporation because of, as I said, the fact that the return on equity was developed at the Entergy Corporation level and then imputed down to Entergy New Orleans, and so that was my data source.

Q. Isn't the cash working capital

adjustment intended to measure Entergy New Orleans' cash needs?

A. Yes, that's correct. And, indeed, that return on equity piece is an important issue in the revenue requirement. And so if a portion of it is a dividend yield applied to the rate base, that is the -- essentially the cash that's being generated through the revenue requirement and available for dividends, all else equal.

Q. And would you agree that every other element of the cash working capital analysis -- well, every element in Mr. Gallagher's cash working capital analysis relies on ENO-specific data? Correct?

A. Yes and no. Some of it has to do with charges from Entergy Services, Inc., and some from Entergy Nuclear. I think that's the name. Entergy Operations, Inc. I'm sorry. You know, but it would measure the effect or the timing of the cash payments to those affiliates specifically for ENO.

Q. Those cash payments, but those are ENO's payments to those affiliates, not Entergy Louisiana's; right?

A. That's true. And the return on equity is applied specifically to ENO. And so it's the return that ENO gets on its rate base and it's the cash piece of that that's available then based upon ENO's characteristics. So I would say, you know, unequivocally that the 3.26 percent dividend yield component of the return on equity is ENO's, ENO-specific.

Q. Again, I didn't ask you about the dividend yield. I asked you about the lags, but that's fine.

So let's go to this. The dividend is paid quarterly. What is that a reference to?

A. The common stock dividend that Entergy Corporation pays is paid quarterly.

Q. And so you intentionally disregarded Entergy New Orleans' payment of dividends in either 2018 or 2017 or even before that; right?

A. I told you the source of the return on equity and the two components, the cash dividend piece and the non-cash growth piece, and so I didn't ignore Entergy New Orleans, but that's what's imputed or pushed into the rate case. Okay? If your question is did I look at the Entergy New Orleans -- the pattern of Entergy New Orleans' cash dividend payments to Entergy Corporation, I did not. We went through that before.

Q. Okay. And so the service period of 45.63 days is not based on ENO-specific data; correct?

A. Well, I mean, it is and it isn't because --

Q. Whoa. Whoa. I'm sorry. Go ahead.

A. Because Entergy Corporation -- A quarter is a quarter, is it not? I mean, can we agree on that? So, you know, Entergy has the same calendar quarter as Entergy New Orleans does. Okay. So there -- Obviously the service period is the same. Okay? Regardless of whether we look at it from Entergy Corporation's perspective or Entergy New Orleans' perspective. But since Entergy New Orleans -- I didn't look at Entergy New Orleans' payment of dividends to Entergy Corporation specifically. I looked at Entergy Corporation's payment of dividends to its shareholders because that was how the return on

REPORTER'S CERTIFICATE

This certification is valid only for a transcript accompanied by my original signature and original required seal on this page.

I, Kathy Ellsworth Shaw, Certified Court Reporter in and for the State of Louisiana, as the officer before whom this testimony was taken, do hereby certify that LANE KOLLEN, to whom oath was administered, after having been duly sworn by me upon authority of R.S. 37:2554, did testify as hereinabove set forth in the foregoing 99 pages; that this testimony was reported by me in stenotype reporting method, was prepared and transcribed by me or under my personal direction and supervision, and is a true and correct transcript to the best of my ability and understanding; that the transcript has been prepared in compliance with transcript format guidelines required by statute or by rules of the board, and that I am informed about the complete arrangement, financial or otherwise, with the person or entity making arrangements for deposition services; that I have acted in compliance with the prohibition on contractual relationships, as defined by Louisiana Code of Civil Procedure Article 1434 and in rules and advisory opinions of the board; that I have no actual knowledge of any prohibited employment or contractual relationship, direct or indirect, between a court reporting firm and any party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter nor is there any such relationship between myself and a party litigant in this matter; I am not related to counsel or to the parties herein, nor am I otherwise interested in the outcome of this matter.

____
KATHY ELLSWORTH SHAW, CCR, RPR
Certified Court Reporter
Curren Court Reporters
749 Aurora Avenue
Suite 4
Metairie, Louisiana 70005

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	
FOR A CHANGE IN ELECTRIC AND	**)**	
GAS RATES PURSUANT TO COUNCIL	**)**	**DOCKET NO. UD-18-07**
RESOLUTION R-15-194 AND R-17-504	**)**	
AND FOR RELATED RELIEF	**)**	

ADOPTING TESTIMONY

OF

LAURA K. BEAUCHAMP

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

MARCH 2019

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Laura K. Beauchamp. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director, Utility Finance and Strategy of Entergy Services, LLC ("ESL"),[1] which is the service company affiliate of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. PLEASE DESCRIBE YOUR DUTIES.

A. As the Director, Utility Finance and Strategy, I am responsible for the financial oversight of Entergy's consolidated utility, which includes each of Entergy's five operating companies.

Q4. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. In 2000, I earned a Bachelor of Science in Management degree with a concentration in Finance, and in 2004 I was awarded a Master of Business Administration degree

[1] On September 30, 2018, Entergy Services, Inc. converted to a limited liability company from a corporation and is now Entergy Services, LLC. ESL is a service company subsidiary of Entergy Corporation that provides technical and administrative services to Entergy affiliates, including Entergy New Orleans, LLC.

with a concentration in Energy Finance. Both of these were granted by Tulane University's A. B. Freeman School of Business.

I have been employed by ESL since 2000 and have held various roles of increasing responsibility in Cash Accounting, Revenue Accounting, Corporate Planning, Regulatory Affairs, Regulatory Strategy, and Finance. I was named Director, Utility Finance and Strategy in October 2018.

Q5. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY AGENCY?
A. Yes. A listing of my prior testimonies is included in Exhibit LKB-1.

Q6. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?
A. I am testifying on behalf of ENO.

II. PURPOSE OF TESTIMONY

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?
A. The purpose of my testimony is to adopt the Revised Direct Testimony of Orlando Todd filed in this proceeding on September 21, 2018. In this regard, I note that Mr. Todd has retired since the submission of his Revised Direct Testimony.

Q8. HAVE YOU REVIEWED MR. TODD'S TESTIMONY?
A. Yes.

Q9. DO YOU ADOPT MR. TODD'S TESTIMONY AS YOUR OWN IN THIS PROCEEDING?

A. Yes.

Q10. ARE THERE ANY REVISIONS TO MR. TODD'S TESTIMONY THAT YOU WISH TO MAKE?

A. No, I am not aware of the need to make any substantive changes to Mr. Todd's testimony.

Q11. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF Louisian

COUNTY/PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared,

LAURA BEAUCHAMP,

who after being duly sworn by me, did depose and say:

That the foregoing is her sworn testimony in this proceeding and that she knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, she verily believes them to be true.

LAURA BEAUCHAMP

Sworn to and

Subscribed Before Me

This 18th Day of March, 2019.

Karen H. Freese

NOTARY PUBLIC

Karen H. Freese - La. Bar No. 19616
Notary Public for the State of Louisiana
My Commission issued for Life

Listing of Previous Testimony Filed by Laura K. Beauchamp

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
09/16/2011	Settlement	EGSL Fuel Adjustment Clause (1995-2004)	LPSC	U-27103
01/26/2012	Settlement	Retail Effects of FERC Opinion Nos. 468 and 468-A and Related Orders	LPSC	U-31099
06/03/2011	Settlement	Little Gypsy Securitization	LPSC	U-31894
07/07/2011	Direct	Carville-Calpine 2011 PPA	LPSC	U-32031
12/21/2011	Rebuttal	Carville-Calpine 2011 PPA	LPSC	U-32031
03/02/2012	Settlement	Carville-Calpine 2011 PPA	LPSC	U-32031
02/15/2013	Direct	EGSL Base Rate Case	LPSC	U-32707
02/15/2013	Direct	ELL Base Rate Case	LPSC	U-32708
03/28/2013	Direct	ELL-Algiers 2013 Rate Case	CCNO	UD-13-01
02/18/2014	Rebuttal	ELL-Algiers 2013 Rate Case	CCNO	UD-13-01
09/27/2013	Settlement	MISO Implementation	LPSC	U-32675