BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW	**)**	
ORLEANS, INC. FOR APPROVAL TO	**)**	
DEPLOY ADVANCED METERING	**)**	**DOCKET NO. UD-16-04**
INFRASTRUCTURE, AND REQUEST FOR	**)**	
COST RECOVERY AND RELATED RELIEF	**)**	

DIRECT TESTIMONY

OF

VICTOR M. PREP, P.E.

ON BEHALF OF

THE ADVISORS TO THE

COUNCIL OF THE CITY OF NEW ORLEANS

MAY 26, 2017

PREPARED DIRECT TESTIMONY

OF

VICTOR M. PREP

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Victor M. Prep. My business address is 8055 East Tufts Avenue, Suite 1250, Denver, Colorado. I am a registered Professional Engineer in the States of Pennsylvania, Colorado, and Louisiana and I am 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 Advisors to 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"). ENO is one of the Entergy Operating Companies[1] and is a wholly-owned subsidiary of Entergy Corporation ("Entergy").

Q. PLEASE SUMMARIZE YOUR RELEVANT EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

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[1] The Entergy Operating Companies ("Operating Companies") are Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc. ("EMI"); Entergy Texas, Inc. ("ETI"); and ENO.

A. Exhibit No. ___ (VMP-2) provides a summary of my relevant education and professional experience and Exhibit No. ____(VMP-3) lists my previous testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the results of my evaluation of ENO's proposed cost benefit analysis, revenue requirements, cost recovery and customer rate impacts related to the Company's October 18, 2016, *Application to Deploy Advanced Metering Infrastructure, Request for Cost Recovery and Related Relief* ("Application"). In particular, I will critique ENO's estimation of advanced metering infrastructure ("AMI") benefits and costs, and I will also address methods of cost allocation and cost recovery. In addition, my testimony will provide the Council with recommendations regarding the customer education program and the treatment of stranded costs related to the existing meters which would no longer be used and useful with ENO's implementation of AMI.

Q. PLEASE SUMMARIZE YOUR MAJOR CONCLUSIONS AND RECOMMENDATIONS.

A. In my testimony, I conclude that ENO's proposed full implementation of AMI, including the supporting systems and timetable, is cost effective for ratepayers. My evaluation of the AMI cost benefit analysis shows a net benefit, including some adjustments to ENO's analysis that I considered necessary, notwithstanding several additional AMI functions that would provide additional net benefit were not included in ENO's analysis.

Specifically, I conclude that ENO's proposed investment in electric and gas AMI meters, communications and supporting IT systems infrastructure is prudent, and that ENO's proposed timeline for meter implementation in 2019-2022 is reasonable. I have estimated the electric and gas customer rate impacts for the years of AMI implementation. To provide additional context to the AMI rate impacts, I have also projected a composite of bill impacts related to ENO regulatory matters that will be concurrent with the AMI implementation. I recommend that ENO should be allowed to recover the stranded costs of existing meters, but at a lower carrying cost equivalent to the cost of long term debt component of ENO's weighted average cost of capital ("WACC"). I recommend that the class allocation of AMI costs and the method of cost recovery should be considered in the Combined Rate Case anticipated in 2018. I recommend that demand response programs enabled by AMI should be expanded to gain additional net benefits from the current proposed investment. ENO should be required to demonstrate that the AMI customer education program is well coordinated with the Energy Smart Behavioral program, because the objectives and methodologies are closely related and the two budgets should be optimized. Lastly, I recommend the Council should provide clear direction regarding the ownership of very large amount of customer usage data soon available as a result of the implementation of AMI.

II. <u>EVALUATION OF ENO'S APPLICATION BEFORE THE COUNCIL</u>

Q. WHAT IS ENO SEEKING IN ITS APPLICATION IN THIS DOCKET?

A. In the Application, ENO seeks Council approval of the Company's deployment of AMI, including the removal and retirement of existing meters, installation of new advanced meters and supporting systems and equipment, and customer education plan. Mr. Vumbaco will address the public convenience and necessity of ENO's proposed AMI implementation and the Council's consideration of public interest. In conjunction with its request for authorization to proceed with full implementation of AMI for electric and gas service and investments in supporting systems, ENO requested that its proposed investments be eligible for recovery from customers, and that the Company will have a full and fair opportunity to recover prudently incurred costs of the project. Specifically, ENO's Application requested an AMI Rate Plan which includes an "AMI Customer Charge," which would be phased in to adjust rates over the period 2019 through 2022; a deferral of all incremental 2017 and 2018 customer education expenses and ongoing AMI operation and maintenance ("O&M") expenses, with subsequent recovery through amortization of a regulatory asset beginning 2020; and a proposal for opt-out fees. Mr. Watson will address ENO's request for the deferral and opt-out fees. Lastly, ENO requests that it continue to recover the remaining book value of the existing electric and gas meters at the current depreciation rate.

Q. HOW HAVE YOU STRUCTURED YOUR TESTIMONY IN SUMMARIZING YOUR EVALUATION OF ENO'S APPLICATION?

A. First, I will discuss the main components of the proposed AMI implementation and evaluate ENO's proposal relative to recent industry practices related to AMI in other jurisdictions. Second, I will address ENO's estimated AMI benefits and costs and evaluate the cost benefit analysis, including some adjustments and additional AMI functions. Third, I will summarize the annual revenue requirements of ENO's AMI proposal and the allocation of AMI costs. Fourth, I will discuss the options for treatment of stranded costs related to the existing meters and provide a recommendation for stranded cost recovery. Mr. Watson will address specific proposals related to the stranded costs. Fifth, I will address cost recovery related to AMI implementation. Sixth, I will develop average customer rate impacts from the proposed AMI implementation, and relate them to other rate impacts that are estimated for the same period. Seventh, I will address the AMI customer education program and accessibility of customer usage data. As part of each section, I provide my recommendations to the Council where appropriate.

III. MAIN COMPONENTS OF ENO'S PROPOSED AMI IMPLEMENTATION AND INDUSTRY PRACTICE

Q. PLEASE DESCRIBE THE COMPONENTS OF ENO'S AMI PROPOSAL.

A. ENO's proposed electric and gas AMI implementation consists of three main components common to most of the AMI systems recently implemented in other jurisdictions: the AMI meters ($29.8 million); a communications network supporting the two-way data communication ($18.8 million); and related and supporting information technology ("IT") systems, including a Meter Data Management System ("MDMS") ($26.1 million). The related IT systems investment includes $3.6 million for updating its legacy Outage

Management System ("OMS") and implementing a new Distribution Management System ("DMS"). Of the $74.7 million of capital investment, $24.3 million of expenditures are expected by year end 2018 when the IT infrastructure necessary to support the advanced meters is placed into plant in service. The remaining $50.4 million of capital investment is largely related to the meter hardware and installation from 2019 through 2021, with the total investment expected to be completed by year end 2022. In its Application, ENO anticipates filing a rate case in 2018[2], which will include a test period on which to base recovery of the $23.4 million of AMI investment closed to plant in service by 2018, as well as the ongoing AMI expenses. I will provide recommendations regarding the timing and method of cost recovery further in my testimony.

Q. DO YOU CONCUR WITH THE ADDITIONAL $3.6 MILLION INVESTMENT INCLUDED WITH THE AMI PROPOSAL FOR THE OMS AND DMS?

A. Yes. These related IT systems leverage the benefits of the AMI investment by providing important near term functions such as outage management support, including restoration verification, predictive asset management, and ability to incorporate distributed energy resources (“DER”), such as rooftop solar photovoltaic (“PV”) systems, which have increased substantially in recent years. These systems will also support future

[2] Application, page 13, and direct testimony of Orlando Todd, Page 9; “It is anticipated that rates resulting from the 2018 Combined Rate Case will be implemented for the first billing cycle of August 2019…”

applications such as potential control and dispatch of DERs and distribution control automation.

Q. IN YOUR OPINION, HAS ENO PROPOSED A REASONABLE TIMELINE FOR AMI DEPLOYMENT AND CAPITAL EXPENDITURES?

A. Yes. Timetables for AMI deployment are usually supported by a business plan that may be a component of a more comprehensive grid modernization plan. AMI business plans have supported deployments as long as ten years.[3] Embarking on the substantial AMI investment entails significant technical, implementation, and strategic risk for the Council and ENO, so the AMI business plan should maximize the potential benefits, and minimize the risk, uncertainties and costs. The design phase and capital spending began in 2015. I believe it is prudent that the design phase be followed by build-up of the various supporting systems and their functional verification and system integration as a single unified system.[4] There must be sufficient time to insure a complete and smooth transition with the billing and other legacy IT systems before the vast amount of interval data from the AMI meters can be accommodated.[5] The final phase of network deployment and installation of advanced meters and components at customers' premises

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[3] Ameren Illinois developed an 8 year, 62% of electric customers AMI meter deployment plan. Under the Massachusetts Department of Public Utilities (DPU) 2014 Opt-In Scenario business case, smart meter deployment, customer load management investments, and the associated outreach and education are spread over 10 years.

[4] The integration of new and upgraded AMI systems with existing Company applications is estimated to involve approximately 150 interfaces between 15-17 different IT systems. Page 10 of the Direct Testimony of Rodney W. Griffith.

[5] As part of Ameren Illinois AMI filing to the Illinois Commerce Commission, AMI infrastructure operations will commence <u>prior to</u> the AMI meter installation.

would begin in early 2019. With the above considerations regarding the timeline, ENO's AMI capital expenditures appear reasonable,[6] particularly with the economies of scale achieved with contemporaneous deployment of AMI by the other Operating Companies. Also, I believe that the proposed deployment timetable provides for the adequacy of consumer protection, education, and safety considerations.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE CAPITAL EXPENDITURES?

A. Yes. I note that of the $61.7 million of electric capital expenditures, $13.2 million have been identified as dedicated Entergy resources.[7] Mr. Griffith lists these capital expenditures as internal resources supporting the Project Management Office for AMI, managing vendors and supporting deployment and business process changes.[8] Since these are significant internal labor costs, and to verify the appropriate basis of cost recovery, I recommend that these costs be examined within the capital and O&M expense accounts for a test year in the Combined Rate Case.

Q. DO YOU CONSIDER ENO'S ESTIMATE OF ONGOING O&M COSTS RELATED TO AMI THROUGH 2022 TO BE REASONABLE?

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[6] The proposed AMI capital investment calculates to an installed cost per AMI meter of $95.87, and a total AMI system cost of $228.30 (including meter cost but excluding the cost of integrated OMS and DMS systems), for both electric and gas combined.

[7] Exhibit OT-1, tab WP-1a.

[8] Direct Testimony of Rodney W. Griffith, page 38.

A. Yes, I have reviewed ENO's workpapers and responses to discovery supporting the ongoing O&M costs related to the AMI implementation as well as the estimation of annual operational benefits offsetting the electric and gas O&M expense, and the estimates of O&M expenses net of benefits are reasonable. The projected O&M expenses relate to vendor-supported systems, network operations center data analytics, detection of unaccounted for energy, communications network maintenance, and various AMI meter services. AMI customer education expenses and O&M expense in 2017 and until the effective date of rates ensuing from the Combined Rate Case will be addressed by Mr. Watson.

IV. BENEFITS VS COSTS RELATED TO AMI

Q. PLEASE EXPLAIN HOW A COST BENEFIT ANALYSIS CAN BE USED IN EVALUATING THE AMI APPLICATION?

A. The AMI business case analysis of benefits and costs is the primary regulatory criteria for evaluating and deciding upon the expenditures for AMI. To justify AMI implementation, identification of all quantifiable benefits and costs, and identification of all difficult-to-quantify or unquantifiable benefits and costs are necessary. A major question facing the Council is whether the significant upfront cost of AMI is justified by the benefits of deployment, many of which are long term projections. Full benefits may only be realized after programs that take full advantage of AMI functionality are implemented, and many of the benefits depend on customer acceptance and adoption of AMI. The cost-benefit analysis is an important decision tool since it could show that, despite a large initial capital investment, the long-term benefits from AMI may provide a net benefit on a present value basis that outweighs the costs. However, due to the different types of available AMI systems, program-specific deployment drivers, and methodologies used in analyzing the costs and benefits, the analysis to determine whether the benefits of AMI outweigh the costs is not straightforward or easily defined. For example, the Electric Power Research Institute ("EPRI") has defined an economic based framework to determine benefits in its analysis of the cost effectiveness of AMI,[9] but several different cost benefit methodologies have been used in other regulatory jurisdictions. To further illustrate methodological differences, it is also necessary to determine whether or not to include stranded costs of legacy meters, or to recognize additional functions (such as demand response) enabled by AMI, both of which can have a significant impact on an AMI cost-benefit analysis. Finally, the value of a cost benefit analysis is enhanced if it includes a discussion of the potential change in benefits and costs that may occur over time assuming various implementation schedules and alternate values for the input variables in order to test assumptions and demonstrate the potential range of results. The analysis of such possible impacts on the results is often described as a sensitivity analysis.

[9] "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" 1020342, EPRI, Jan. 2010.

Q. WAS A SENSITIVITY ANALYSIS PERFORMED ON THE RESULTS OF THE AMI COST BENEFIT ANALYSIS?

A. No. The Company did not include a sensitivity analysis on its AMI business case in its Application. I did not deem it necessary to assess the impact of various AMI implementation schedules, and I considered that no additional analysis using alternate input variables was necessary based on my evaluation of the work papers supporting the Company's exhibits. However, I do have several observations regarding the Company's analysis, which I will discuss later in my testimony after presenting certain revisions I proposed to ENO's cost benefit analysis.

Q. PLEASE DESCRIBE THE DIFFERENCES IN METHODOLOGIES OR STRUCTURES THAT HAVE BEEN USED IN COST BENEFIT ANALYSES.

A. The cost benefit analysis can be structured as economics-based, forward looking, or as a projection of the impacts of costs and benefits on revenue requirements presented to the regulator in subsequent, near-term rate cases. This fundamental conceptual difference of a totally incremental versus embedded accounting cost perspective has confronted regulators for several decades in terms of reconciling marginal cost based rates with revenue requirement constraints based on forward looking accounting cost based test periods. The utility company could be expected to make business decisions using a business case based primarily on incremental costs and benefits, rather than sunk costs. The regulator, however, has to balance the interests of company shareholders with the interests of the ratepayers. For ratepayers, the prospective changes to the embedded costs of projected revenue requirements is an important consideration.[10] Both perspectives have merit and should be considered in structuring cost benefit analyses. Specifically, an economics based evaluation of AMI can be made of the net present value of incremental benefits and incremental costs. Alternatively, an estimate of annual revenue requirements impacts related to the AMI implementation could be projected into the business case period. The projection would incorporate the estimated timeline of benefits and costs impacting the annual revenue requirements to determine the present value of the net revenue requirement impacts. Using the revenue requirements approach, all cost and benefit categories can be calculated as financial flows over the course of the AMI project lifetime using an appropriate discount rate to determine present value. Depending on the perspective chosen, some jurisdictions' cost benefit analyses have used customer-based discount rates,[11] while others have used the cost of capital appropriate for the company in question. I recommend that the projected revenue requirements approach be used to evaluate the incremental impacts of AMI, using ENO's weighted average cost of capital as the discount rate.

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[10] In New Jersey Department of Public Utilities Docket No. ER16060524 6, the Division of Rate Counsel stated: "Rockland's (AMI) petition offered an economic analysis which failed to present a net present value revenue requirements analysis – in other words, the impact that AMI will have on the ratepayers who will be paying for the program. (p.14) [w]ithout results that are presented in terms of present value of revenue requirements, it is not possible to make a determination of the impacts of an investment on customers." (p.15)

[11] The Ameren Illinois March 30, 2012 AMI filing with the ICC included a cost benefit analysis taken from the customer perspective, with costs and benefits modeled as revenue requirement adjustments. As such, the discount rate that Ameren Illinois used for the NPV analysis was a customer-perspective discount rate (20-Year Treasury Bill rate).

Q. WHAT OTHER DIFFERENCES EXIST IN DEVELOPING THE COST BENEFIT ANALYSIS?

A. An additional issue must be considered between the two different structures in defining the costs that are related to AMI implementation. The cost analyses of some jurisdictions have embraced a straightforward embedded cost concept by incorporating the total stranded (not yet recovered) cost of existing (legacy) meters being replaced, while other jurisdictions have used an alternate approach by defining all costs and benefits that are incremental when compared with a baseline or "business as usual" scenario. The baseline scenario reflects the related costs or benefits that would be anticipated if the investment were not made, so the relevant costs are those incurred to deploy AMI relative to the baseline. Specifically, this alternate baseline approach includes only the incremental, often accelerated, annual cost recovery of the stranded costs relative to the existing depreciation cost recovery of the existing meters.[12] The ratepayer impact (benefits net of costs) would reflect the amortization of net plant value cost of existing meters no longer used. If the cost benefit analysis is structured as financial flows of cost and benefit impacts on projected revenue requirements, the analysis should also provide a calculation of the period where benefits exceed costs, based on the present value of the annual cash flows of the AMI investment.

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[12] The 2012 Ameren Illinois cost-benefit analysis filed at the ICC recognized as a separate line item AMI-related stranded costs. Their analysis used the baseline approach, wherein the difference between the existing & accelerated depreciation related to the existing meters for each year of the business case was included in the cost benefit analysis as a cost incremental to the baseline. Ameren Illinois' filing was referenced as consistent with the guidelines recommended by the Illinois Statewide Smart Grid Collaborative.

Q. WHAT IS YOUR RECOMMENDATION REGARDING HOW STRANDED COSTS SHOULD BE INCORPORATED IN THE COST BENEFIT ANALYSIS?

A. I recommend that the baseline approach should be used, where only the cost increment or difference between the accelerated cost recovery and the existing depreciation cost recovery of the replaced meters is included in the cost benefit analysis.

Q. WHAT ARE THE BROAD CATEGORIES OF AMI BENEFITS?

A. A "benefit" can be defined as an impact of the AMI implementation that has value to the utility, a customer's household, or society in general. I consider AMI benefits to be in four fundamental categories: economic,[13] reliability and power quality, environmental, and security and safety. Economic benefits include immediate and long term reduced costs and system efficiency through improved utilization of assets. Reliability and power quality benefits include improvements in system reliability and power quality (*i.e.*, reduction in interruptions and power quality events). Environmental benefits include reductions in negative externalities such as reduced impacts of climate change and pollution. Security and Safety benefits include improved energy and cyber security and reductions in injuries and property damage. The magnitude of these benefits is influenced by customer behavior and AMI functionality. Customer behavior is guided by a customer education program accompanying AMI implementation, which is vital to achieve real change in how customers use electricity and think about energy pricing.

[13] Economic benefits defined as those primarily related to utility operational costs.

AMI functionality is dependent on two basic concepts: 1) communication to the meter, and from the meter to customer devices; and 2) access to interval data on a real time basis.

Q. PLEASE DESCRIBE THE ESTIMATED BENEFITS AS PRESENTED IN THE APPLICATION.

A. ENO defines benefits from their AMI Application as quantified benefits broken down into two categories: (1) operational benefits; and (2) other benefits. ENO defines the operational benefits as: (i) routine meter reading; (ii) meter services; and (iii) reduced customer receivable write-offs. Other benefits are defined by ENO as: (i) consumption reduction; (ii) peak capacity reduction; (iii) unaccounted for energy ("UFE") reduction; and (iv) elimination of the need to maintain and replace existing meter reading equipment.[14] Although a number of other benefits have been identified by other utilities in conjunction with their respective AMI deployments, these other potential benefits were not included with ENO's cost/benefit analysis.[15]

Q. PLEASE SUMMARIZE HOW THE AMI BENEFITS RELATED TO CONSUMPTION AND PEAK REDUCTION WERE ESTIMATED BY ENO.

A. ENO's projection of energy and peak reduction benefits is based on customer behavioral response driven largely by customer access to detailed usage data through the web portal

[14] Direct testimony of Jay A. Lewis, page 4.

[15] Ibid.

(with data accessible the following day) and text and email notifications. Estimated reductions and corresponding benefit are based on a percent of ENO's demand and energy forecast for residential and commercial customers. The estimated percent reduction of the demand and energy forecast is derived from several assumptions. A behavioral response electric usage reduction of 1.75% and gas usage reduction of 0.75% are assumed for residential and commercial customers, further assumed to be distributed evenly for each hour of the year. To estimate peak behavioral response, ENO assumes that 5% of residential customers would voluntarily take action in response to text or email alerts of peak conditions, and that this 5% will also voluntarily reduce 7.5 % of their peak usage on the days when the alerts are sent. ENO further assumes that the uniform hourly energy reduction is distinct and not correlated with the peak usage response. ENO supported these assumptions in the Application by behavioral response studies from other jurisdictions where AMI was implemented.[16]

Q DO YOU AGREE WITH ENO'S ASSUMPTIONS REGARDING THE CONSUMPTION AND PEAK BENEFITS RELATED TO AMI?

A. I do not agree with ENO's assumption that energy reduction related to AMI is uniform for all hours of the year, and that it is distinct and not correlated with the peak usage response. However, ENO's assumptions were conservative relative to the ranges of usage reduction provided in Exhibits JAL-3 and JAL-4, and in ENO's response to CNO

[16] Exhibit JAL-3 provides the consumption reduction of other utilities related to AMI, and Exhibit JAL-4 provides the peak reduction of other utilities related to AMI.

2-8 ENO reduced the percent usage reduction to 1.5%. With these considerations, and with the revisions to the benefits calculations based on ENO's updated load forecast, I believe that the estimates of consumption and peak benefits are within the range of reasonableness.

Q. WHAT OTHER POTENTIAL BENEFITS COULD HAVE BEEN QUANTIFIED AND INCLUDED IN THE AMI COST BENEFIT ANALYSIS?

A. ENO repeatedly addressed the feasibility of several potential benefits in its Application,[17] yet no attempt was made to quantify benefits from these "future products and services" enabled by AMI over the projected 15-year period of the analysis. Noticeably absent were benefits related to AMI-enabled demand response (direct load control or time varying rates). Demand response program benefits were projected in the 2015 Integrated Resource Plan ("IRP") based on saturation and demographic data in ENO's recent DSM Potential Studies. The Meter Data Management System ("MDMS") is being developed with the capability to handle demand response programs, which is another indication that the Company is preparing for demand response programs in the near term. Mr. Lewis stated that some utilities have offered specific pricing techniques, such as time-varying pricing, to provide customers with additional incentives for consumption reduction in

[17] "AMI is the technical foundation and platform for the modernization of ENO's electric grid that will enable future products and services to customers." (Dawsey, p.5); "ENO may seek to implement such (demand response) programs as part of subsequent phases of its overall effort to modernize its grid, or through AMI-enabled energy efficiency programs." (Dawsey, p.21); "AMI enabled offerings may prompt changes in the Company's energy efficiency programs included as part of its later energy efficiency filings." (Dawsey, p.22); and "In the future, the addition of DERs, electric vehicles ("EVs"), and microgrids would be expected to increase the amount of data that AMI will be required to transfer and process to ensure reliability and efficient grid operations." Direct Testimony of Rodney W. Griffith, page 7.

conjunction with AMI deployment, but that the Company does not plan to provide dynamic pricing options when it initially deploys AMI.[18] The 2015 ENO DSM Potential study projects potential savings of 24.9 MW from residential direct load control and 9.4 MW from dynamic pricing by 2034, with benefit to cost ratios of 6.7 and 3.8 respectively. Including the significant potential benefits of demand response in the cost benefit analysis would make the business case for AMI even more positive.

Q WHAT AMI BENEFITS WERE NOT READILY QUANTIFABLE, BUT WERE ADDRESSED IN THE AMI COST BENEFIT ANALYSIS?

A. Several benefits enabled by AMI were not quantified, including those related to reliability, safety, net energy metering ("NEM", rooftop solar PV systems) customers, and increased availability of hourly billing demand data. Regarding reliability, AMI will enable rapid and accurate detection of service problems, faster outage restoration, timely outage restoration communications with customers, and additional distribution system optimization and monitoring.[19]

Safety benefits may result from AMI substantially reducing the number of personnel and vehicles that are in the field,[20] as well as from more timely alerts of gas leaks at service locations. Regarding NEM benefits, the AMI meters have the capability to provide interval data needed to bill customers with distributed generation (*e.g.*, rooftop solar

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[18] Direct testimony of Jay A. Lewis, page 15.

[19] Direct testimony of Dennis Dawsey, page 26.

[20] Direct testimony of Dennis Dawsey, page 25.

systems), eliminating the need for bi-directional meters for customers with self-generation equipment.

Remaining AMI benefits that weren't quantified include more effective responses to customer billing questions and issues,[21] and a more credible quantification of customer peak demands based on actual usage versus estimates based on monthly data. Although these potential benefits are difficult to quantify, they provide additional support for AMI implementation.

Q. WHAT DO YOU CONCLUDE ABOUT THE AMI BENEFITS THAT WERE NOT INCLUDED IN THE COST BENEFIT ANALYSIS?

A. The AMI benefits that were not quantified are nonetheless an important positive addition to the business case for AMI implementation. In my view, the analysis results are therefore conservative with respect to the calculation of benefits.

Q. WHAT STRUCTURE DID YOU USE IN CONDUCTING AN AMI COST BENEFIT ANALYSIS?

A. I used a projected revenue requirements approach, where I included the incremental benefits and costs related to the proposed AMI implementation as annual impacts to total revenue requirements over the 15-year period of the AMI business case. The projected revenue requirements cost benefit analysis utilizes data contained in ENO's Application,

[21] Direct testimony of Dennis Dawsey, page 4.

extended and adjusted as appropriate. I found it appropriate to include some adjustments to ENO's calculation of energy and peak reduction benefits, as well as to costs related to the AMI implementation.

Q. WHAT ADJUSTMENTS WERE APPLIED TO REVISE ENO'S ESTIMATES OF THE ANNUAL ENERGY AND PEAK REDUCTION BENEFITS ATTRIBUTABLE TO AMI?

A. The adjustments were based on updating the electric load forecast used in Exhibit No. JAL-2 which calculated the annual benefits. The sales forecast in MWh used in Exhibit No. JAL-2 shows increasing residential sales of roughly 0.4%/year over the years of AMI deployment. In February 2017, ENO distributed an updated electric load forecast indicating that load would be approximately 3.8% below the previous (2016) forecast, growing at approximately the same rate. ENO's response to CNO 2-8 provided residential and commercial sales projections from the lower, updated load forecast, noting that the updated load forecast includes the impact of AMI deployment. The updated forecast resulted in lower energy and demand benefits over the 15-year period of $110.6 million and $33.7 million respectively (nominal $), compared to $137.9 million of energy and $35.0 million of demand benefits (nominal $) as presented in the Application. The revised AMI-related energy and demand benefits were determined by CNO witness Ms. Crouch, and are presented in her Exhibit No.__(CAC-4).

Some inconsistencies were apparent in developing these adjustments. The residential sales projection of the updated forecast (per ENO's response to CNO 2-8) declined through 2027, and did not correlate with the residential sales forecast provided in Exhibit No. JAL-2. Furthermore, the percent energy usage reduction used to estimate AMI benefits was 1.75% in Exhibit No. JAL-2 compared to 1.5% in the response to CNO 2-8. The calculations and inconsistencies are discussed further by Ms. Crouch.

Q. WHAT ADJUSTMENTS WERE APPLIED TO THE AMI-RELATED COSTS?

A. Because I used a projected revenue requirements approach to the cost benefit analysis, it was appropriate to consider a projected cost impact of the recovery of existing meter investment.[22] I thought it instructive and helpful for the Council to consider two alternate cost benefit results which incorporated the cost recovery of existing meter investment: one which includes the total cost impact of stranded costs using accelerated recovery over the 15-year period of the business case, and the other presenting an incremental cost impact using the alternate baseline approach which I discussed previously. I will address the formulation of an accelerated cost recovery of existing meters later in my testimony.

[22] In its 2014 Grid Modernization Plan, the Massachusetts Department of Public Utilities instructed distribution companies to include a narrative regarding how estimated stranded costs impact the overall business case. The Orange & Rockland response to New York Department of Public Service interrogatory (Dec. 2014, set 10, #7) confirmed that stranded costs were evaluated in the context of the overall AMI cost benefit analysis. The Ontario Electric Board considers stranded costs as a major AMI cost along with capital and O&M (Smart Metering Initiative, 2005–2014, Prepared by the Office of the Auditor General of Ontario). In Order 83410, the Maryland Public Utility Commission expressly stated that Baltimore Gas & Electric's analysis did not include "the undepreciated value of existing, fully operational meters that would be retired before the end of their useful lives." In Order 83531, the Commission restated it was appropriate to include the costs of legacy meters in evaluating AMI cost-effectiveness. In Kentucky Public Service Commission Case Number 2016-00152, Duke Energy Kentucky acknowledged that its AMI cost-benefit analysis failed to take stranded costs into consideration.

Q. WAS THE RECALCULATION OF BENEFITS AND COSTS DISCUSSED ABOVE INCORPORATED INTO A REVISED AMI COST BENEFIT ANALYSIS?

A. Yes. Ms. Crouch calculated these revised cost benefit analyses under my supervision, and the results are presented in Exhibit No._(CAC-5) for the electric and gas operations. I note that the revised cost benefit analyses show an electric AMI net benefit of $84.7 million nominal, and $16.0 million net present value ("NPV"), and a gas AMI net benefit of $4.5 million nominal and a net cost of $2.0 million NPV. For total ENO gas and electric the revised cost benefit analysis shows a net benefit of $89.2 million nominal and $14.0 million NPV compared to the net benefit of $101 million nominal and $27 million NPV presented in the Application.[23] Table 1 presents the comparison of AMI net benefits.

Table 1
AMI Net Benefits Comparison
(Dollars in Millions)

	Advisors' Revised Net Benefits		Application Net Benefits	
	Nominal $	PV $	Nominal $	PV $
Electric	$84.7	$16.0	$104	$30
Gas	$4.5	$(2.0)	$(3)	$(3)
Total ENO	$89.2	$14.0	$101	$27

[23] Direct Testimony of Jay A. Lewis, page 8.

Q. WHAT OTHER OBSERVATIONS DO YOU HAVE REGARDING THE ASSUMPTIONS IN THE COST BENEFIT ANALYSIS?

A. As I mentioned previously, one of the two basic concepts upon which AMI functionality is dependent is access to the customer's interval data on a real time basis. ENO asserts in its Application: "Because of AMI, customers will be informed with more detailed usage information upon which to base their decision."[24] However, the customer's usage decision relates to real time (today), while the more detailed usage information from the portal is only available the following day, and then only when the customer has the opportunity to log on to the customer account on the portal to view that information. AMI functionality is dependent on access to interval data on a real time basis, and devices such as in-home displays, which were used in the AMI Low Income Pilot, provide real time access and should be offered as an option to customers with the AMI installation.

Also, customer notifications of peak conditions have not been a routine practice previously,[25] so I recommend that such notifications under AMI should be made after receiving the customer's prior consent.

Lastly, while ENO stated that its gas cost benefit analysis does not produce a net benefit,[26] the cost benefit analysis I recommended using the revenue requirement baseline

[24] Direct testimony of Dennis Dawsey, page 23.

[25] "This program will provide text message and/or email notifications to customers (subject to an opt-out procedure and applicable legal requirements related to such communication channels) suggesting that they take steps to reduce their usage during certain times of peak load on the overall system." (Dawsey, p. 22).

approach in Exhibit No.__(CAC-5) shows a benefit of $4.5 million (nominal), primarily due to the accelerated cost recovery of existing meters. I also concur with the benefits described in ENO witness Ms. Bourg's testimony supporting AMI implementation for gas service. I recommend that ENO's electric and gas service should be considered together[27] in evaluating the cost effectiveness of full AMI implementation.

Q. BASED ON YOUR EVALUATION OF THE BENEFITS AND COSTS RELATED TO ENO'S PROPOSED IMPLEMENTATION OF AMI, DOES AMI PRESENT A NET BENEFIT TO RATEPAYERS?

A. Although my analysis results in lower net benefits than those presented in the Application, in my opinion ENO's proposed AMI investment is still cost-effective to ratepayers, although at a lesser level than ENO asserts. With ENO's updated, lower electric load forecast, the estimated energy and demand net benefits are lower, as shown in Exhibit No._ (CAC-5) for the combined electric and gas operations, but still provide support for cost-effectiveness. In addition, there are several benefits which I have discussed which have not been quantified in either ENO's or my analysis, including net benefits from additional functions enabled by AMI that have been confirmed with AMI implementation in other jurisdictions. ENO has noted for future consideration such additional unquantified functions such as demand response.

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[26] Direct testimony of Jay A. Lewis, page 27.

[27] ENO currently has approximately 197,000 retail electric customers and 107,000 retail gas customers.

VI. TREATMENT OF STRANDED COSTS RELATED TO EXISTING METERS

Q. WHAT TREATMENT OF STRANDED COSTS DID ENO INCLUDE IN ITS APPLICATION?

A. The Company proposes that it continue to include the remaining book value of the existing meters in rate base, and to depreciate those assets over the remaining useful life at current depreciation rates. While this proposal is consistent with the normal treatment of asset retirements, I note that full AMI implementation represents a complete replacement and upgrade of assets to achieve additional functions and long term benefits beyond the existing service provided to ratepayers.

Q. IN YOUR VIEW, WHAT IS AN APPROPRIATE TREATMENT FOR STRANDED COSTS WHEN RELATED TO THE FULL IMPLEMENTATION OF AMI?

A. Stranded costs and risks related to estimating the net cost of full AMI implementation and determining their projected revenue requirements and revenue impacts should be shared between ENO and ratepayers. A regulated utility is expected to select resources which provide reliable service at the lowest possible cost and with reasonable levels of risk shared between the Company and ratepayers. A major capital investment resulting from full AMI implementation, and based on an economic analysis driven by net present value of projected net benefits incremental to the existing cost of service, clearly represents some sharing and risk related to stranded costs. While some jurisdictions have delayed

AMI implementation to minimize stranded costs,[28] the growing national trend is full implementation, notwithstanding the issue of stranded costs. The retail regulators of Kentucky, California, Massachusetts, Pennsylvania, and New York are among the many states, including the Ontario Electric Board, that have all recently ordered all electric utilities to develop internal policies and procedures for making smart grid investments, under the premise that AMI investments are necessary to deliver the level of service desired by the commissions. The commissions are not only encouraging these investments, but also directing utilities to make them.[29]

Q. WHAT DO YOU RECOMMEND REGARDING THE RECOVERY OF THE STRANDED COSTS RELATED TO THE EXISTING METERS?

A. I believe that the Company should be entitled to recover the undepreciated or remaining net plant cost of existing meter investment, although the complete replacement of those assets with AMI on the basis of future benefits must be considered in determining the

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[28] The Connecticut attorney general asked the Department of Public Utilities Commission to deny Connecticut Light & Power's AMI proposal in 2007, arguing that the upgrade should be postponed until the existing mechanical meters require replacement. Duke Energy Kentucky, in its AMI request stated: "Given the Company's relative size, such a financial impact to the Company is certainly a factor in the Company's ability and willingness to proceed with the Meter Upgrade investment." Until proposed an opt-in AMI program to incrementally spend capital on meter replacements to avoid the stranded costs of replacing existing meters before they have reached the end of their useful life (p. 27 of AMI Utility Trends in the NEEP Region, Feb. 2017). After an initial AMI filing, Ameren Illinoi refocused their AMI implementation to 62% of the electric utility over eight years. These actions to minimize stranded cost recovery reinforce the argument that complete replacement of existing meters with full AMI implementation requires non-traditional approaches to cost recovery of the stranded assets.

[29] As an example, in 2014 the Massachusetts Department of Public Utilities (DPU) required investor-owned utilities to develop grid modernization plans, which requires utilities to propose 5 year Short Term Investment Plans supported by a comprehensive business case analysis and discussion of stranded costs.

method of cost recovery. I recommend that the responsibility for that cost recovery should be shared between the Company and ratepayers.

Q. CAN YOU EXPLAIN FURTHER HOW YOU WOULD INTERPRET THE FULL IMPLEMENTATION OF AMI AND TOTAL REPLACEMENT OF EXISTING METERS TO REQUIRE A SHARING OF THE STRANDED COST RECOVERY RESPONSIBILITY BETWEEN THE COMPANY AND RATEPAYERS?

A. Any sharing of stranded costs must be based on principle and consideration must be given to the adverse impacts on any group of stakeholders. Stranded cost recovery should ensure that the allocation related to the sharing of stranded costs is equitable and that the time period for recovery is appropriate. No group should achieve a windfall at the expense of another. It has been argued that ratepayers are paying for two sets of meters, including those being replaced,[30] yet it is reasonable that the Company's unrecovered investment must be also recognized. I note the following extract from a recent case in Louisiana[31] where the concept of "reasonably necessary" is addressed:

> "*Generalizing, these cases (Hope Bluefield) hold the rate-making process rests on a balancing of interests between the investors and the consumers. The method used to balance the interests of the investors and the consumers is well established. The initial determination that must be made is the utility's future revenue requirement." "A general*

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[30] In New Jersey Department of Public Utilities Docket No. ER16060524 6, the Division of Rate Counsel stated: "Because Rockland is also requesting stranded costs for its legacy meters, customers will be forced to pay for two meters simultaneously under Rockland's proposal. Co. wants unprecedented guarantee that it will be allowed to recover $8.9 million of stranded costs for its retired meters in a future rate case. If granted, these requests will eliminate regulatory risk for Rockland's shareholders and shift such risk to its ratepayers."

[31] Central Louisiana Electric Co. v. Louisiana Public Service Commission. No. 86-CA-1781. Supreme Court of Louisiana, June 22, 1987.

rule of utility regulation is that ratepayer-consumers should only pay the utility company a fair return on facilities and capital actually used and useable for production of service to these ratepayers." "The "used and useful" determination consists of two components: (1) in service, and (2) reasonably necessary. City of Evansville, 339 N.E.2d at 597." "Second, as to the "reasonably necessary" requirement,… there was no indication that poor business judgment had been employed…" Latourneau v. Citizens Utilities Co., 125 Vt. 38, 209 A.2d at 313, (1965), the Supreme Court of Vermont."

In the case of the full implementation of AMI meters, I believe that "reasonably necessary" component of the Louisiana. Supreme Court's determination would apply. Ratepayers could have continued to receive reliable service with existing meters, without incurring the additional costs of AMI technology. The complete replacement of the existing meters is "reasonably necessary" to achieve long term benefits. Neither the ratepayers nor ENO should be unduly burdened with this major transition in service. The statutory orders and directions for AMI implementation mentioned previously would fit this interpretation which would provide some consideration for sharing the responsibility for the unrecovered cost of the replaced meters. Existing electro-mechanical metering technologies cannot deliver the advanced functions and usage information only recently deemed important enough by commissions to require wholesale jurisdictional utility development of AMI investment. Existing metering cannot be upgraded absent wholesale system replacement, due to the AMI interconnected and integrated network technology.

Q. HOW WOULD YOU RECOMMEND BALANCING THE INTERESTS OF THE COMPANY AND RATEPAYERS IN THE RECOVERY OF STRANDED COSTS?

A. At least two public utility commissions, California and Kansas,[32] have denied 100% return of or on legacy meters. In addition, the commissions in Georgia, Illinois, Michigan, Pennsylvania, and Texas have granted a return, but not a full WACC return, on legacy meters. The California Public Utilities Commission ("CPUC"), in 2011,[33] reduced the carrying cost of legacy meters below WACC (specifically, 6.3% or 1.55% below WACC). I note that ENO's long term debt cost rate as computed in WACC in that same year, 2011, was 6.2%, which is comparable to the CPUC carrying cost rate. In May 9, 2013, the CPUC similarly reduced the carrying cost of legacy meters to 220 basis points below San Diego Gas & Electric's WACC (to 6.2%). The CPUC reasoned that even though the existing meters were no longer used and useful, the CPUC encouraged AMI deployment and wanted to share costs between the utility and ratepayers, and also for the interests of consumers in encouraging utilities to invest in further innovative technologies. I recommend that the sharing of costs be accomplished by using a lower carrying cost in recovering the investment in existing meters.

Q. WHAT CARRYING COST RELATED TO COST RECOVERY OF THE EXISTING METERS DO YOU RECOMMEND?

A. Based on the above considerations, I recommend that ENO recover the remaining net plant in service cost of existing meters at ENO's cost of long term debt component of

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[32] The Kansas Commission decided not to grant a return on the utility's investment in legacy meters (but allowed a 10 year amortization which was less than the remaining depreciable life). Sept.10, 2015, KCP&L Docket 15-KCPE-116-RTS.

[33] Refer to the May 3, 2011 Decision in PG&E case, Dockets U39MA.09-12-020.

WACC. The sharing is accomplished by a compromise of shared costs between ENO and the ratepayers: ENO recovers its investments with improved cash flow over a shorter period with no disallowance to shareholders, albeit at a lower carrying cost than one providing for a full return on investment, while ratepayers pay for significant AMI investment as well as continue to pay for the cost recovery of existing meters which are no longer in service.

Q. DO YOU AGREE WITH MR. WATSON'S RECOMMENDATION REGARDING THE TERM OF THE COST RECOVERY OF THE EXISTING METERS?

A. Yes. I agree with Mr. Watson that the stranded cost of the existing meters be recovered over a 15-year period. This term is consistent with the expected useful life of the AMI meter assets, and the range of years used for the accelerated recovery of AMI stranded assets in several jurisdictions.[34]

Q. HOW DOES THE RELATIVE AMOUNT OF ENO'S STRANDED COST TO THE PROPOSED AMI INVESTMENT COMPARE TO THE RELATIVE AMOUNTS OF STRANDED COSTS IN OTHER JURISDICTIONS?

A. ENO's net plant in service (unrecovered book cost) of existing meters as of December 31, 2016, is $43.8 million. Expressed as a percent of useful lives, the remaining book cost

[34] Request of Kenergy Corp for Approval to Establish a Regulatory Asset, Amortized over a ten year period, Case No. 2015-00141 (Ky.PSC. August 31, 2015); The Kentucky Commission authorized a 15-year amortization period in the South Kentucky RECC rate case; in Baltimore Gas & Electric's recent depreciation proceeding, Case No. 9355, the parties agreed to a ten-year recovery period for legacy meter costs; Kansas Commission granted a ten year amortization on the unrecovered investment in legacy meters, KCP&L Docket 15-KCPE-116-RTS.

is 83% for electric meters and 95% for gas meters.[35] This $43.8 million of stranded cost associated with the existing meters is approximately 58% of the $75 million capital investment in AMI implementation proposed by the Company. In comparison, I have observed noticeably lower percentages of stranded cost (in the range of 20%) relative to the proposed AMI investment for other utilities.[36] Notwithstanding the substantial amount of ENO's stranded costs relative to other AMI implementations, I do not believe that the stranded cost recovery issue should negatively impact the Council's decision regarding ENO's proposed full implementation of AMI.

Q. DO YOU RECOMMEND THAT A REGULATORY ASSET BE ESTABLISHED TO RECOVER THE AMI STRANDED COSTS OVER 15 YEARS?

A. Yes. The recovery of stranded meter costs due to AMI implementation through creation of a regulatory asset has several precedents. A request to create regulatory assets for the early retirement of electro-mechanical meters satisfies the criteria for a regulatory asset because the requested regulatory assets represent extraordinary or non-recurring expense that over time will result in a result in a savings that fully offsets the costs. The request for a regulatory asset also satisfies another criteria - an expense resulting from a statutory

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35 See the direct testimony of Byron S. Watson, Tables 4 & 5.

36 Eversource Utility ($165 million out of $946 million or 17%); Ontario Electric Board's 2014 estimate of total stranded costs was approximately 20% of AMI investment; Duke Energy Kentucky, Case No. 2016-00152, stranded costs are approximately 20% of AMI investment; BG&E AMI 2016 rate Case, Case NO.9406, stranded costs are approximately 20% of AMI investment.

or administrative direction.[37] Although the Council has not specifically directed ENO to implement AMI and its supporting systems, AMI and its direct and enabled benefits have been anticipated in several resolutions[38] and strongly supported by stakeholders. Mr. Watson has performed the analysis of the regulatory asset related to stranded costs, amortized over a 15-year period.

V. AMI REVENUE REQUIREMENTS AND COST OF SERVICE

Q. BASED ON THE INFORMATION ENO PROVIDED IN THE APPLICATION AND DISCOVERY RESPONSES PLEASE EXPLAIN HOW ANNUAL TOTAL AMI REVENUE REQUIREMENTS WERE DEVELOPED BY ENO..

A. In its Application, ENO witness Orlando Todd presented an estimated four year (2019–2022) non-fuel revenue requirement consisting of the proposed AMI implementation's incremental non-fuel costs including O&M, depreciation, taxes, and return on capital investment.[39] The electric plant in service amount in 2018, from AMI capital expenditures of 2015 through 2018, is estimated at $23.2 million,[40] and depreciation

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[37] PA PUC directed Companies to charge the incremental cost of removal of Legacy Meters to the regulatory asset account containing the remaining cost of the retired Legacy Meters. Smart Meter Procurement and Installation, Docket No. M-2009-2092655 (Order entered June 24, 2009). OG&E sought authorization of regulatory assets for AMI costs and stranded cost recovery (OG&E at APSC re AMI; Docket No. 10-109-U Order No. 8). The Kentucky PSC authorized regulatory assets for Kenergy Corp's loss on the disposal of its electro-mechanical meters in Case No. 2015-00141, for Taylor RECC's regulatory asset for retired meter expense in Case No. 2008-00376, and for early meter retirements in a South Kentucky RECC rate case.

[38] Resolutions R-16-106, R-17-32, and R-17-100.

[39] Direct Testimony of Orlando Todd, Exhibits OT-1 and OT-2, for electric and gas operations respectively.

[40] The Advisors assume that the 2018 plant in service amount would include Allowance for Funds Used During Construction ("AFUDC"), but have not been able to verify such in the Application or through discovery.

expense is estimated based on a 15 year life. To project O&M expenses ENO assumed a general inflation rate of 2% per year and to project return on rate base ENO assumed that the current return on equity ("ROE") would apply after the Combined Rate Case in 2018.[41] The other project-related costs that are included in ENO's non-fuel revenue requirement are customer education expense, property tax, and amortization of expenses deferred from 2017 and 2018.

Q. DID YOU PREPARE ANY ESTIMATES OF AMI REVENUE REQUIREMENTS?

A. Yes, I prepared AMI fixed costs-related revenue requirements for the years 2019-2022 based on ENO's information with adjustments deemed appropriate.

Q. WHAT ADJUSTMENTS DID YOU APPLY IN PREPARING A REVISED PROJECTION OF AMI REVENUE REQUIREMENTS?

A. The following adjustments were applied to ENO's projected annual AMI revenue requirements in Exhibit Nos. OT-1 and OT-2: (1) amortization of deferred expenses; (2) stranded cost recovery related to existing meters; and (3) ENO's WACC.

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[41] Given the current ROE's being awarded by regulatory commissions in the current economic environment as summarized by Public Utility Fortnightly (November 2016), ranging from 9.00% to 10.90%, this may be overly optimistic on ENO's account.

For the pre-tax WACC, I assumed the most recent ROE approved by the Council of 9.95%,[42] a common equity ratio of 50%, and the cost of long term debt and preferred equity as of June 30, 2016. My adjustments eliminate the Company's proposed amortization of deferred O&M expenses, the reason for which is addressed in Mr. Watson's testimony. The annual revenue requirement related to the net plant in service or stranded costs of existing electric and gas meters is estimated to be approximately $4.7 million.[43] My revenue requirement adjustment to stranded costs reflects the recovery of ENO's remaining investment in existing meters at a carrying cost lower than the Company's proposal, and with an amortization of 15 years, as discussed further in Mr. Watson's testimony. Ms. Couch incorporated these adjustments, and the revised revenue requirements for the AMI implementation are shown on Exhibit No.__(CAC-6) for both the electric and for gas operations.

Q. WHAT METHOD DID THE COMPANY PROPOSE FOR THE ALLOCATION OF AMI IMPLEMENTATION COSTS?

A. In its Application, the Company proposed to allocate the direct costs of AMI implementation on a customer basis. AMI costs consist of those costs specific to ENO's jurisdictional grid, as well as a portion of the total Entergy AMI system costs which are

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[42] ENO's current Electric ROE of 11.1%, approved in the 2008 rate case, will be reviewed by the Council in the Combined Rate Case, and be reflected in the revised rates anticipated to be effective in the 2nd half of 2019. The Council approved an ROE of 9.95% in the 2013 rate case for Algiers. Also, a review of ROEs authorized by retail regulators, as reported by Public Utilities Fortnightly (November 2016), identifies 18 new retail authorized ROEs in 2016, averaging 9.71%.

[43] Direct testimony of Byron S. Watson, page 20.

shared by all Entergy Operating Companies. The shared components of the Entergy system-wide AMI deployment, such as the IT systems and project support,[44] are assigned by Entergy based on the total number of customers located in each Operating Company's jurisdiction.

Q.` DO YOU AGREE WITH ENO'S APPROACH REGARDING THE ALLOCATION OF AMI COSTS TO CUSTOMER CLASSES?

A. No. Unlike existing meters with the sole function to generate billing, AMI technology provides many functions and benefits which must be recognized in the allocation of AMI costs.

Q. WHAT COST ALLOCATION METHODOLOGY DO YOU CONSIDER MORE APPROPRIATE REGARDING RECOVERY OF AMI COSTS?

A. All electric and gas customers will be receiving the benefits of AMI during deployment, which benefits will grow as each advanced meter is placed in service. The recovery of AMI costs should be allocated to customers on the basis of the net benefits attributed to the AMI implementation. A pure customer count used as the basis for allocating all costs related to AMI ignores the wide range of potential benefits related to usage and demand. If the meter reading function were only considered for the purpose of producing a monthly bill, then a customer-related allocation would be appropriate; but then the large

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[44] Shared AMI system costs include the cost of the communications network design and the head-end component of the communications network, the MDMS, the DMS, the OMS, certain software licensing costs, costs related to the meter test facility, as well as the overall system integration and project support.

investment in AMI would be unnecessary. AMI is being undertaken to achieve several significant benefits, and from recognized regulatory practice in cost allocation, it follows that the cost responsibility for AMI should be assigned in a manner which correlates with the benefits. On that basis, I developed a weighted allocation factor, based on the relative weighting of each benefit and cost related to AMI implementation, and considering only the AMI functions proposed by the Company in its Application. The result was a 51.78% electric and 69.49% gas residential class allocation of AMI fixed cost related revenue requirements based on weighted customer, energy and peak demand allocation factors. The AMI allocation factor derivation is shown in Exhibit No. __(VMP-4), and is summarized on Table 2 with a comparison to the allocation in the Application.

Table 2
AMI Revenue Requirement Weighted Allocation (%)

		Residential	Commercial	Industrial	Other
Electric	Application Allocation	89.6	8.4	1.0	1.0
	Revised Weighted Allocation	51.8	14.9	32.4	0.8
Gas	Application Allocation	94.8	4.9	0.1	0.3
	Revised Weighted Allocation	69.5	10.4	19.6	0.5

Q. HAVE YOU SUMMARIZED YOUR ALLOCATIONS OF THE AMI TOTAL ANNUAL REVENUE REQUIREMENT INCLUDING STRANDED COSTS?

A. The results of my allocations of AMI total electric and gas revenue requirements for years 2019 through 2023 are summarized on Exhibit No. __(VMP-5).

VII. AMI COST RECOVERY

Q. PLEASE SUMMARIZE ENO'S PROPOSAL FOR AMI COST RECOVERY.

A. ENO proposed an AMI Rate Plan which would recover AMI costs, net of certain quantified O&M benefits, through an "AMI Customer charge"[45] phased in over the period 2019 through 2022. ENO expects electric plant in service closings from AMI to grow from $23.2 million in 2018 to $61.7 million in 2021, and gas plant in service closings from AMI to grow from $1.0 million in 2018 to 12.9 million in 2021.[46] Contemporaneously with these AMI assets being placed in service from 2018 through 2019, the Company is requesting that an "AMI Customer Charge" be implemented, calculated on a per-customer basis, that would recover the costs of the AMI deployment in rates.

Q. DO YOU AGREE WITH ENO'S PROPOSAL FOR AN AMI CUSTOMER CHARGE TO RECOVER AMI COSTS?

A. No. The recovery of AMI costs through an AMI Customer Charge is single issue ratemaking, which is discussed in detail by Mr. Watson.

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[45] "At this time, ENO would propose to display the AMI Customer Charge as a line item on the electric and gas customer bills for all rate schedules. However, the manner in which the charge will be presented is a question that may better be addressed in connection with the 2018 Combined Rate Case…" Direct testimony of Orlando Todd, page 19.

[46] Direct testimony of Orlando Todd, Table 1.

Q. HOW DID THE COMPANY PROPOSE THAT THEIR AMI CUSTOMER CHARGE BE IMPLEMENTED IN CONJUNCTION WITH THE COMBINED RATE CASE ANTICIPATED IN 2018?

A. The Company proposes that the AMI Customer Charge be implemented at the time that the Council sets new rates as part of the Combined Rate Case,[47] and that the AMI incremental fixed-cost-related annual revenue requirement should ultimately be reflected in rates following the Combined Rate Case through the proposed AMI Customer Charge. Specifically, the AMI fixed costs would be included in determining ENO's annual fixed cost revenue requirement, but the proposed AMI Customer Charge would provide projected revenue based on an estimate of the following year's AMI cost. ENO has cited Rider tariffs previously approved by the Council as precedent for such cost recovery outside of the traditional base rate mechanisms. ENO assumes that the AMI Customer Charge would be based on the ROE resulting from the Combined Rate Case as well as ENO's actual capital structure at the time AMI assets would be implemented. And assuming a formula rate plan ("FRP") is approved to commence in 2020,[48] ENO proposes that the AMI Customer Charge would provide projected revenue which would be trued-up within the annual FRP revenue requirement adjustments.

[47] "It is anticipated that rates resulting from the 2018 Combined Rate Case will be implemented for the first billing cycle of August 2019, and implementation of the initial AMI Customer Charge would be part of the rate design of those rates." Direct testimony of Orlando Todd, page 9.

[48] "ENO anticipates requesting the implementation of a FRP and has assumed implementation of an FRP in the results of its AMI Rate Plan reflected in this testimony." Direct testimony of Orlando Todd, page 7. If revised rates from the Combined Rate Case were effective in 2019, an FRP, if approved, would likely be filed in the first half of 2020, with the FRP rate adjustment effective in the second half of 2020.

Q. DO YOU CONCUR WITH ALL OF ENO'S PRINCIPAL ASSUMPTIONS?

A. No. While there are well established regulatory principles stating that ENO should have a full and fair opportunity to recover prudently incurred costs of whatever project and level of capital spending that the Council might approve, that "fair opportunity" should not be limited to or strictly defined as a contemporaneous cost recovery rate mechanism. A full rate case provides the Council and all stakeholders the appropriate regulatory forum to completely evaluate all significant changes to the Company's total revenue requirements, including major capacity additions. I recommend that the Council adhere to that sound regulatory practice with regard to AMI. Cost recovery mechanisms other than base rates have been approved for recovery of substantial non-fuel/fixed costs when a full rate case was not imminent or expected to be completed in a reasonable time around the initial incurrence of those substantial costs, but only until new rates are set. However, ENO has stated in the Application that the targeted date for AMI meter implementation would be relatively close to the effective date of revised rates from the Combined Rate Case. Furthermore, in past rate actions ENO has not hesitated to support a comprehensive forward-looking approach toward cost recovery by including several pro-forma adjustments applicable to the prospective period(s) in which new rates would be effective. In addition, step or staged rate increases to accommodate separate timing with respect to increased costs of service have been accepted by parties to past rate action dockets. After the revenue requirement impacts of AMI are completely vetted in the Combined Rate Case relative to the total ENO cost of service, including the important details involving rate design and allocated cost recovery for each of the customer classes, the Council can decide on the timing of any rate changes for AMI cost recovery that may be appropriate to correlate with AMI implementation.

As Mr. Watson demonstrates, ENO has not demonstrated that its financial stability and credit ratings would be adversely affected if the opportunity for cost recovery were provided by other than a contemporaneous cost recovery Rider. If pro-forma adjustments in the Combined Rate Case provided the basis for recovery of the Council-approved capital spending,[49] the assumption that FRP rate adjustments would follow in the next annual period of 2020 would reinforce the opportunity for timely AMI cost recovery. Furthermore, regarding FRP assumptions, I do not concur that the cost recovery for a capital project approved by the Council should be evaluated outside of an FRP bandwidth formula for its initial year. An FRP revenue adjustment, determined relative to a Council approved ROE, should be based on the revenue requirement related to all fixed costs, including first year project costs. If AMI were approved for full meter implementation starting in 2019, under ENO's FRP bandwidth proposal it would be approximately two years later in October 2021, with the second FRP revenue adjustment, that rates would reflect the AMI revenue requirement evaluated in terms of ENO's approved ROE. The additional concerns with ENO's proposed AMI customer charge are discussed further in Mr. Watson's testimony.

[49] Presumably, the 2018 Combined Rate Case would have revised rates effective in 2019, around the expected time of AMI implementation. ENO's inclusion of pro-forma adjustments in past rate actions to reflect anticipated cost recovery in revised rates, as of the effective date, has been acceptable to the Council, and is considered sound regulatory practice in many other jurisdictions.

Q. ARE THERE OTHER ENO ASSUMPTIONS WITH WHICH YOU AGREE?

A. Yes. I agree that the cost recovery for the approved project should be based on the authorized ROE that the Council may set as part of the Combined Rate Case, as well as ENO's actual capital structure reflected in any potential future FRP revenue adjustments, as reasonably applied. I also agree that the project's revenue requirement should be evaluated on an annual basis during the period 2018 - 2021, integral to the evaluation of ENO's total annual revenue requirements.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING ENO'S PROPOSED COST RECOVERY PLAN?

A. Yes. ENO has proposed that if the Council does not approve an FRP in the Combined Rate Case, a separate annual true-up of its proposed AMI Customer Service Charge should be instituted.[50] However, I note that an annual evaluation of AMI cost recovery would be included as part of an annual review of ENO's total revenue requirements accomplished with any revenue decoupling mechanism approved by the Council. In Resolution No. R-16-103, the Council ordered ENO to include in its next base rate case filing a proposal for a three year full decoupling mechanism, with or without an FRP, to begin with the implementation of rate changes arising from the Combined Rate Case. If an FRP is not adopted in the Combined Rate Case, the target revenue requirement for

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50 "The Company therefore requests that the Commission's approval of the Electric Rate Plan not be contingent upon the existence of the FRP" and "ENO would reflect an annual true-up of the estimated AMI Implementation Costs and AMI O&M Expense and the Operational Benefits included in the annual AMI Customer Charge estimates." Direct testimony of Orlando Todd, page 19.

annual decoupling revenue adjustments could include significant changes to fixed costs. This requirement for ENO to propose a three year decoupling mechanism without an FRP represents an additional opportunity for ENO's recovery of AMI-related fixed costs and provide the Company with the necessary assurance that it will have a reasonable opportunity to fully recover its prudently-incurred AMI investment for the benefit of its customers.

VIII. ESTIMATED RESIDENTIAL RATEPAYER BILL IMPACTS

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE AVERAGE ESTIMATED RATEPAYER BILL IMPACTS FOR EACH YEAR FROM THE TOTAL AMI REVENUE REQUIREMENTS.

A. The annual kWh sales for ENO, including Algiers customers, for year 2019 and thereafter were provided by customer class and numbers of customers for each annual period in Supplement 3 of ENO's Final 2015 IRP Report. After determining the revised total AMI revenue requirements for each 12-month period (2019–2022) in Exhibit No.__(VMP-5), I performed the class allocation of the non-fuel revenue requirements using the weighted cost allocation methodology that I discussed previously and summarized in Exhibit No.__(VMP-4). The customer class billing determinants were then applied to the annual AMI revenue requirements allocated to the residential class and all other customers. For the years 2019 through 2022, the resulting estimated residential bill impacts for a 1,000 kWh/ month bill are summarized on Table 3 below and developed on Exhibit No. __(VMP-6).

Table 3 **AMI - Residential Estimated Average Monthly Bill Impact**				
Estimated Bill Impact	***2019***	***2020***	***2021***	***2022***
Electric	$1.12	$1.48	$1.44	$1.02
Gas	$0.63	$1.16	$1.14	$1.02

IX. INTEGRATION WITH OTHER CONCURRENT BILL IMPACTS

Q. ARE THERE OTHER SUBSTANTIAL ENO REGULATORY APPLICATIONS THAT ARE EXPECTED TO IMPACT ENO'S RATES AROUND THE TIME OF THE PROPOSED IMPLEMENTATION OF AMI?

A. Yes. Exhibit No. __(VMP-7) presents a composite estimated summary of ENO's regulatory rate applications, and their average monthly bill impacts that are expected to be concurrent at the time of AMI full implementation in 2019 and subsequent near term years.[51] Each of the revenue requirements and bill impacts in Exhibit No. __(VMP-7) are projected to be incremental to the recovery of existing costs and ratepayer total bills.

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[51] In its Application, ENO recognizes additional impacts to ratepayers from other regulatory actions. "These (AMI) investments are in addition to the significant other investments the Company has recently made and is currently planning to make through 2018 for the benefit of its customers (e.g., Union Power Block 1 ($237 million), Ninemile Unit 6 Power Purchase Agreement (approximately $18 million annual revenue requirement)." Direct testimony of Orlando Todd, page 4.

Table 4 below summarizes the composite of these incremental bill impacts, including the AMI bill impacts discussed previously and shown on Exhibit No.__(VMP-6).

Table 4
Composite of Estimated Residential Average Monthly Bill Impacts (1000 kWhs Electric; 50ccf Gas)

	2019	*2020*	*2021*	*2022*
AMI-Electric	$1.12	$1.48	$1.44	$1.02
PPCACR Realignment[52]	$2.54	$2.40	$2.28	$2.18
Energy Smart	$3.24	$3.78	$4.34	$4.88
Alternative Proposal New Orleans Power Station[53]	$4.97	$4.42	$3.67	$2.96
ENO Restructuring	$(0.76)	$(0.75)	$ -	$ -
Electric Bill Impact	**$11.11**	**$11.34**	**$11.73**	**$11.05**
AMI – Gas	$0.63	$1.16	$1.14	$1.20
Gas Rebuild (GIRP)	$3.45	$4.70	$5.88	$6.95
Total Estimated Monthly Bill Impact[54]	**$15.19**	**$17.20**	**$18.76**	**$19.01**

The non-fuel cost recovery of Union Power Block 1 and the Ninemile 6 PPA are expected to be realigned into new base rates with the completion of the Combined Rate

52 In 2019, the Purchased Power Capacity Acquisition Cost Recovery ("PPCACR") Rider billed in an average residential monthly bill of 1000 kWh is projected to be $13.05, consisting of $9.54 for Union Power Block 1 and $3.51 for Ninemile 6. The incremental residential bill impact shown relates to the increased cost recovery from the change in allocation factors anticipated with the realignment of PPCACR into revised base rates.

53 On April 21, 2017, ENO filed a Status Report with the Council, pursuant to Judge Gulin's Order dated March 10, 2017, providing an update regarding its Supplementary Application concerning the New Orleans Power Station. In the Status Report, ENO stated that it expects to include in its Supplemental Filing (targeted for late June or early July 2017) the alternate proposal for a 126 MW unit, comprised of seven 18 MW reciprocating engines.

54 This bill impact total does not include any revisions to base rates that may ensue from other costs evaluated in the Combined Rate Case.

Case in 2019. ENO's base rate tariffs were last revised in the 2008 rate case (followed by three FRP adjustments), and notwithstanding how base rates might be adjusted based on a 2018 test year, including the combination of ENO legacy and Algiers customers, the realignment into base rates of Union Power Block 1 and Ninemile 6 non-fuel costs will have a higher relative bill impact for residential customers since the allocated cost recovery used in the existing PPCACR Rider is expected to be revised in the Combined Rate Case with the use of a capacity allocation methodology. Based on the last rate case cost allocation methodologies, the residential class cost responsibility could be approximately 20% greater than that experienced with the existing PPCACR Rider cost recovery which is based on a kWh allocation methodology.

The anticipated growth of the Energy Smart Program will likely correspond to a substantial increase in revenue requirements for the 2019 - 2024 period since existing funding sources, such as Rough Production Cost Equalization funds[55] and ratepayer guaranteed savings from ENO's Community Development Block Grant ("CDBG") tax proposal,[56] will have been depleted by the time AMI meters would commence implementation. The projected revenue requirements related to Energy Smart were

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[55] ENO estimates the Energy Smart funding balance as of March 2017 to be approximately $12 million based on account information provided on February 8, 2017. The current Program Year cost is $7.8 million. Assuming Program Year budgets are based on a targeted increase in kWh reduction of 0.2% of sales pursuant to Resolution No. R-17-100, funds from existing sources are projected to be depleted prior to the second half of 2019. For subsequent years, Energy Smart is assumed to be funded primarily from increases in ratepayer revenues.

[56] In Resolution No. R-15-14, the Council approved ENO's CDBG tax proposal and the ratepayer benefits from $7.3 million of Guaranteed Savings. In Resolution R-15-544, the Council directed ENO to use the Guaranteed Savings to fund up to $182,500 of Energy Smart Program costs each month, prospectively, over the period December 2015 through March 2019.

developed based on the total budgets for program years 7, 8, and 9, and the amount of annual kWh reduction corresponding to the savings target pursuant to Resolution No. R-17-100. The funding from residential revenues was estimated to be in proportion to the recent program year costs related to residential Energy Smart programs.

Table 3 also shows estimated residential bill impacts related to the costs of ENO's anticipated alternate proposal for a New Orleans Power Station of approximately 126 MW.[57] Pending the filing of ENO's Supplementary Application, expected by July 2017, I have tentatively projected an increase in revenue requirements beginning in 2019 related to the alternate proposal. The estimated annual revenue requirements are based on a preliminary estimate of installed cost for comparable units.[58] A demand allocation was used to estimate the customer class revenue requirements related to the alternate proposal.

The projected bill impacts include ENO's investment in its Gas Infrastructure Rebuild Plan ("GIRP") which has been approved to continue through 2017 and 2018,[59] with the capital costs from those years recovered in prospective base rates. Following the rate freeze during 2017 and 2018, the increases in revenue requirements from GIRP costs are

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[57] On April 21, 2017, ENO filed a Status Report with the Council, pursuant to Judge Gulin's Order dated March 10, 2017, providing an update regarding its Supplementary Application concerning the New Orleans Power Station. In the Status Report, ENO stated that it expects to include in its Supplemental Filing (targeted for late June or early July 2017) the alternate proposal for a 126 MW unit, comprised of seven 18 MW reciprocating engines.

[58] Installed cost was estimated from the reported equipment and installation costs of recently installed reciprocating engines at Alexandria, Louisiana, and an estimate of annual revenue requirements was based on ENO's NOPS Application. The supporting calculations are included in Exhibit No._(VMP-7) workpapers.

[59] Resolution No. R-17-6, Council Docket No. UD-07-02.

expected to begin in 2019 with the conclusion of the Combined Rate Case.[60] Since the GIRP costs are considered to be capacity-related, those revenue requirements were allocated to customer classes consistent with the gas capacity cost allocation methodology used in the last rate case. On Exhibit No. __(VMP-7), the gas customer bill impacts related to gas AMI and GIRP costs are shown separately and also as a cumulative bill impact for both electric and gas customers, since approximately 55% of ENO's customers receive a utility bill for both electric and gas service.[61]

Table 3 also includes estimated bill impacts from potential ratepayer credits of $5 million in 2019 and $5 million in 2020, related to ENO's Restructuring Proposal in Docket No. UD-16-03, pending full Council approval of the Agreement in Principal. The ratepayer credits were allocated to customer classes on a kWh basis.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE COMPOSITE RATEPAYER BILL IMPACT ANALYSIS?

A. Yes. I believe that the sum of the estimated bill impacts discussed above and summarized in Table 3 and Exhibit No. __(VMP-7) are on the conservative side as an estimate of the composite increase in base rates of residential bills that will be experienced by customers during the 12 month periods shown. As noted previously, the

[60] The Council is expected to consider approval of continued GIRP investment after 2017 and 2018 in the Combined Rate Case.

[61] As of December 31, 2015, ENO serves 197,000 electric customers and 107,000 gas customers.

composite of these bill impacts do not include any other changes to ENO's base rates or Riders that may result from other costs evaluated in the Combined Rate Case

<u>CUSTOMER EDUCATION AND CUSTOMER DATA ACCESSIBILITY</u>

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE AMI CUSTOMER EDUCATION PROGRAM IS IMPORTANT TO ACHIEVE A SUCCESSFUL AMI IMPLEMENTATION?

A. In its Application ENO states: "Simply being better informed about their energy use in conjunction with new tools like targeted text alerts and conservation tips is enough to induce energy savings among some customers."[62] Indeed, a substantial portion of the benefits supporting AMI implementation rely on behavioral response,[63] without considering any demand response programs such as time varied pricing or direct load control. A customer education program is absolutely necessary if behavioral response is to be achieved to the extent estimated in ENO's benefits analysis. Should benefits be increased with AMI-enabled demand response, customer education will also be a necessary component.

Q. WHAT CONCERNS DO YOU HAVE REGARDING ENO'S PROPOSED AMI CUSTOMER EDUCATION PROGRAM?

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[62] Direct testimony of Ahmad Faruqui, page 17.

[63] ENO's benefits analysis shows $139 million of $273 million (in nominal dollars) related to energy and peak demand reduction enabled by AMI (direct testimony of Jay A. Lewis, Table 1, page 7)

A. ENO's Customer Education Plan states: "This plan is separate and distinct from energy efficiency customer education plans."[64] The Council-approved current Energy Smart Implementation Plan for Program Years 7-9 includes a Behavioral Pilot Program with a cornerstone customer education program very similar to the AMI Customer Education Plan.[65] Also, both programs will be using ENO's customer portal[66] as a primary means to achieve behavioral response. Both AMI Customer Education Plan Phase I (2017-2018, during pre-deployment) and Phase II (2019-2021, during individual activation of online energy management information and tools) run concurrently with the Energy Smart Behavioral Program in Program Years 7-9 (2017-2019).

Q. WHAT DO YOU RECOMMEND REGARDING THE AMI CUSTOMER EDUCATION PROGRAM AND THE ENERGY SMART BEHAVIORAL PROGRAM?

A. I recommend that both programs should not be implemented as separate and distinct, but rather should be integrated, both functionally and in terms of budget and the Company should be directed to file with the Council such an integrated plan.

Q. WHAT ARE THE BUDGETS FOR BOTH PROGRAMS?

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64 Direct Testimony of Dennis P. Dawsey, Exhibit DPD-2, page 3.

65 "This combination of weather data, meter data, and consumer analytics creates an environment where customers not only understand their energy usage…but also encourages them to act. Changes in behavior are spurred by tips customized to each customer…This combination of regular messaging regarding energy use…drives predictable changes in behavior for proven DSM results." (Page 2 of Accelerated Innovation ("AI") response to ENO RFP).

66 "The MyMeter customer engagement portal will be fully integrated with the ENO website…and will be available to all ENO customers." (Page 10 of Accelerated Innovation response to ENO RFP)

A. The Energy Smart Behavioral Program has had a budget for 12 months ending March 2017 of $300,000, and a budget for Program Years 7–9 of $944,596, for a total of $1,244,596. The AMI Customer Education Plan has a proposed budget of $1,982,920 through AMI meter deployment in 2021. With an integration of both programs, it is reasonable that some efficiency of expenditures could be achieved within the combined budgets of $3.2 million. I recommend that ENO should revise and submit the budgets of both programs, indicating how the programs will be implemented in a coordinated effort.

Q. WHAT CONCERNS DO YOU HAVE REGARDING CUSTOMER DATA ACCESSIBILITY?

A. ENO has indicated that it has existing policies regarding customer data,[67] and that controls related to AMI data storage and transmission are being developed as part of the AMI design phase. The importance of customer usage data has been markedly increased with AMI by both the large amount and granularity of data received by the Company, and its accessibility by customers must be defined in addition to the data controls being developed. The extensive usage data would be valuable to customers evaluating on-site generation as well as independent demand response aggregators providing benefits to customers. The issues of ownership of customer usage data and the Company's ongoing obligation to protect customer information must be recognized and balanced with

[67] Direct testimony of Dennis Dawsey, page 28: "These policies include the Protection of Information Policy, which states the requirements and expectations to safeguard customer information that include a requirement that such data be protected against "loss, damage, theft, unauthorized access, unauthorized reproduction, unauthorized duplication, unauthorized use, unauthorized distribution, unauthorized disclosure, misappropriation, inappropriate disposal and mishandling."

requests for accessibility to large amounts of customer data. Mr. Watson discusses these concerns in greater detail and provides recommendations to the Council.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIRMATION

STATE OF COLORADO)
)
COUNTY OF DENVER)

I, Victor M. Prep, am the person identified in the attached Testimony and such testimony was prepared by me or under my direct supervision; the answers and information set forth therein are true to the best of my knowledge and belief, and if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Victor M. Prep

Subscribed and sworn to before me
this 26th day of May, 2017.

Robin M Shaver-LaBarge

NOTARY PUBLIC

ROBIN MARIE SHAVER-LaBARGE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20064043695
MY COMMISSION EXPIRES APRIL 3, 2019