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November 30, 2017

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

Re: Supplemental and Amending Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief
CNO Docket NO. UD-16-02

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of the Public Version of Entergy New Orleans, Inc.'s ("ENO") Rebuttal Testimony in the above-referenced docket. This filing includes the Rebuttal Testimony and Exhibits of Charles L. Rice, Jr., Seth E. Cureington, Charles W. Long, Shauna Lovorn-Marriage, Bliss M. Higgins, and Dr. George Losonsky. Please file an original and two copies into the record in the above-referenced matter, and return a date stamped copy to our courier.

In connection with the Company's filing, a Confidential Version of the above-described documents bearing the designation "Highly Sensitive Protected Materials" are being provided to the appropriate reviewing parties pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of Highly Sensitive Protected Materials pursuant to Council Resolution R-07-432, the disclosure of which could subject not only the Company, but also its customers, to a substantial risk of harm. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

Thank you for your assistance with this matter.

Sincerely,

Brian L. Guillot

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BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**))))))**	**DOCKET NO. UD-16-02**

REBUTTAL TESTIMONY

OF

CHARLES L. RICE, JR.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

NOVEMBER 2017

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EXHIBITS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Charles L. Rice, Jr. I am President and Chief Executive Officer ("CEO") of Entergy New Orleans, Inc. ("ENO" or the "Company"). My business address is 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of ENO in support of the Company's Supplemental and Amending Application ("Supplemental Application") in this proceeding. The Supplemental Application seeks, among other things, approval to construct the New Orleans Power Station ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 MW or, alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator Sets ("Alternative Peaker").

Q3. ARE YOU THE SAME CHARLES L. RICE WHO FILED DIRECT TESTIMONY AND SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF ENO?

A. Yes.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to introduce ENO's rebuttal filing and respond to certain testimony filed on behalf of the Advisors to the Council of the City of New

Orleans (the "Advisors"), as well as the Deep South Center for Environmental Justice ("DSCEJ"), the Alliance for Affordable Energy ("AAE"), 350 Louisiana – New Orleans, and the Sierra Club (collectively, the "Joint Intervenors"), and Air Products and Chemicals, Inc. ("Air Products"). First, I provide an overview of the testimony of the Company's other witnesses who are submitting Rebuttal Testimony. Second, I discuss the testimony of the Advisors, the Joint Intervenors, and Air Products on the need for NOPS. Third, I address certain community and environmental concerns raised by the Joint Intervenors. Fourth, I discuss cost recovery and certain issues raised by the Joint Intervenors concerning ENO's rates and investment in distribution upgrades. Finally, I conclude with a brief discussion of the significant benefits to customers expected from NOPS and why construction of NOPS will serve the public convenience and necessity.

Q5. PLEASE SUMMARIZE THE POSITIONS OF THE PARTIES THAT HAVE FILED TESTIMONY IN RESPONSE TO ENO'S SUPPLEMENTAL APPLICATION.

A. The Advisors recommend that the Council approve construction of the Alternative Peaker, explaining that "the RICE Alternative presents the most viable alternative for the Council's consideration in the instant docket to resolve ENO's current transmission system reliability issues and, accordingly, is the Advisors' collective recommendation to the Council for approval."[1] The Advisors further explain that the public interest is served by construction of the Alternative Peaker *in combination* with the incorporation of

[1] Vumbaco Direct at 8–9.

renewable technologies and realistically achievable and cost-effective demand-side management ("DSM") potential in ENO's service territory.[2]

Although their seven witnesses put forth neither an independent forecast of ENO's long-term capacity needs nor a proposed portfolio of resources to meet those needs, the Joint Intervenors recommend that the Council deny ENO's Supplemental Application. They also raise concerns about the impact of NOPS on the environment and the community in New Orleans East.

Finally, Air Products, through its witness Maurice Brubaker, takes the position that the Alternative Peaker would be a more suitable capacity addition than the CT and has some beneficial characteristics, including flexibility in deployment and operations, as compared to the CT.

II. WITNESSES SUBMITTING REBUTTAL TESTIMONY

Q6. WHAT OTHER WITNESSES ARE SUBMITTING REBUTTAL TESTIMONY IN SUPPORT OF NOPS?

A. For ease of reference, below is an overview of the topics addressed by ENO's rebuttal witnesses:

- **Seth E. Cureington** – Mr. Cureington responds to the testimony of Joint Intervenors' witnesses Robert M. Fagan and Dr. Elizabeth A. Stanton regarding the need for NOPS and potential resource alternatives and explains why NOPS is the best option to meet ENO's future capacity needs, given the Company's unique planning circumstances and the local reliability, market, and supply-related

[2] *See id.* at 9.

benefits NOPS would provide. Mr. Cureington also responds to certain arguments, positions, and recommendations made by the Advisors' witnesses Joseph W. Rogers and Byron S. Watson regarding the economic case for NOPS. Mr. Cureington identifies unreasonable assumptions made by Mr. Rogers and explains why the Council should not rely on his resulting economic analyses and Mr. Watson's corresponding revised bill impacts. He also responds to a few of the issues raised by Joint Intervenors' witness Dr. Beverly Wright regarding ENO's site selection and public participation in ENO's 2015 Integrated Resource Plan ("2015 IRP") and the Company's proposal to construct NOPS.

- **Charles W. Long** – Mr. Long addresses the testimony of Joint Intervenors' witnesses Mr. Fagan (and Mr. Fagan's adopted testimony of Patrick W. Luckow), Peter J. Lanzalotta, and Dr. Stanton regarding the alternative of upgrading transmission instead of constructing NOPS. Mr. Long explains that relying on transmission upgrades instead of building NOPS would expose the City to the risk of cascading outages until all upgrades are completed and still would not provide the local reliability benefits that NOPS would. Mr. Long additionally responds to several observations by Advisors' witness Philip J. Movish, noting that they agree on many points, including the risks inherent in following the Joint Intervenors' recommendations and the benefits of adding local capacity in the City of New Orleans. He also responds to Mr. Movish's observation regarding an error in the levels of DSM included in ENO's reliability analysis cases that included the Council's 2% DSM goal. On Mr. Movish's recommendation, Mr. Long reran the reliability analysis cases to correct the error, concluding that the error had no material effect on the results of the cases that included the Council's 2% goal.

- **Shauna Lovorn-Marriage** – Ms. Lovorn-Marriage responds to the testimony of the Advisors and Air Products concerning ENO's cost-recovery plan and sets forth the Company's position in response to that testimony. She also addresses certain competitive procurement issues raised by Air Products' witness Mr. Brubaker and Joint Intervenors' witnesses Philip Henderson and Dr. Stanton.
- **Bliss M. Higgins** – Ms. Higgins, an expert in air emissions and permitting, responds to the testimony of Joint Intervenors' witness Dr. George Thurston regarding the effects that NOPS will have on air quality, reiterating her position that air emissions from NOPS will be within standards established by the United States Environmental Protection Agency ("EPA") that are protective of public health with an adequate margin of safety. Ms. Higgins additionally responds to Joint Intervenors' witness Dr. Wright regarding the effects of NOPS on residents living in New Orleans East and the appropriateness of ENO's applications for certain permits for NOPS. Ms. Higgins explains that no residents live within one mile of the proposed NOPS site, that NOPS will not have adverse impacts in the areas of air quality, public health, and groundwater withdrawal on the people of New Orleans East, and that ENO has made appropriate environmental permit requests.
- **Dr. George Losonsky** – Dr. Losonsky responds to the testimony of Joint Intervenors' witness Dr. Alexander Kolker regarding the effects of groundwater withdrawal associated with NOPS. Dr. Losonsky refutes Dr. Kolker's

recommendation that additional analyses should be conducted of the risks associated with groundwater usage by NOPS, summarizes the scientific and mathematical calculations that Dr. Losonsky performed to independently evaluate any potential effects of groundwater usage, and reiterates his conclusion that groundwater withdrawal associated with the CT or the Alternative Peaker will not increase or contribute to subsidence or cause damage to infrastructure in New Orleans East.

III. ENO HAS DEMONSTRATED THE NEED FOR NOPS

Q7. PLEASE SUMMARIZE THE POSITIONS OF THE JOINT INTERVENORS AND AIR PRODUCTS ON WHETHER ENO HAS ESTABLISHED THE NEED FOR NOPS.

A. Joint Intervenors' witnesses Dr. Stanton and Mr. Fagan argue that ENO has not established the need for NOPS because, in their view, ENO has not adequately explored alternative methods for meeting its customers' needs, including DSM, renewable resources, transmission upgrades, and capacity purchases.[3] They recommend further study of these possibilities and assume that the Midcontinent Independent System Operator, Inc. ("MISO") short-term capacity market will be able to cover any capacity shortfall that ENO experiences. Additionally, Dr. Wright asserts that ENO has repeatedly overestimated customer need for electricity and not explained forecast changes, implying that ENO purposely inflated its forecasts of future capacity needs in order to justify building a new plant.[4] Finally, on behalf of Air Products, Mr. Brubaker

[3] *See* Stanton Direct at 6–7; and Fagan Direct at 4–8.

[4] *See* Wright Supplemental at 9–11.

asserts that there is not an immediate need for the amount of capacity that would be provided by the CT resource, advocating for adding a smaller amount of RICE capacity now and waiting to see how loads actually materialize in the future.[5]

Q8. DOES THE COMPANY STILL RECOMMEND CONSTRUCTION OF THE CT AS AN OPTION TO MEET ITS LONG-TERM RESOURCE NEEDS?

A. Yes. As I stated in my Supplemental and Amending Direct Testimony, the CT has a nominal capacity of approximately 226 MW, at summer conditions. The Company has an overall capacity need that grows to approximately 248 MW during the 20-year planning horizon and an average peaking need of 342 MW during that period. The CT would substantially address these long-term needs. Further, as Mr. Cureington explains in his Rebuttal Testimony, ENO has proposed two viable alternatives for the Council's consideration: the CT would be expected to meet and exceed the Company's target reserve margin over the planning horizon, and the Alternative Peaker would be expected to meet that target only for the first half of the planning horizon and thereafter leave the Company short. Selection of either option for NOPS would be a prudent way to meet the overall need for capacity, as well as mitigate the substantial peaking and reserve deficit. As Mr. Cureington discussed in his Supplemental and Amending Direct Testimony, the additional capacity associated with the larger CT option would provide additional benefits to mitigate market and supply-related risks, which is reasonable in consideration of ENO's unique planning circumstances. The smaller Alternative Peaker would provide similar benefits over the first half of the planning horizon.

[5] *See* Brubaker Additional Direct at 6.

Q9. HOW DO YOU RESPOND TO THE RECOMMENDATION OF THE JOINT INTERVENORS CONCERNING THE NEED FOR NOPS?

A. The Joint Intervenors' witnesses Dr. Stanton and Mr. Fagan do not appear to be familiar with the collaborative approach to long-term resource planning that the Council has established, as evidenced by Council Resolution R-14-224. In the course of preparing its 2015 IRP, ENO engaged in extensive modeling and considered a wide range of different future scenarios and resource alternatives. That process identified the Company's substantial need for peaking and reserve capacity. As detailed in Mr. Cureington's Rebuttal Testimony, Dr. Stanton and Mr. Fagan offer a string of unsupported assumptions, citing to macro-level information not specific to ENO, its service area, or the Company's unique planning circumstances, and they have not conducted any analysis of the total combined costs and benefits of the various resource possibilities that they suggest. Nor have they shown that delaying NOPS and conducting further analyses would benefit ENO's customers. Furthermore, if their speculation about load and resource possibilities is incorrect, then ENO could find itself in need of capacity and reliant on the short-term MISO capacity market at a time when market prices are projected to be substantially increasing. The Company would also be without a hedge against higher Locational Marginal Prices in the New Orleans Load Zone and potentially facing North American Electric Reliability Corporation violations. And Dr. Stanton and Mr. Fagan fail to acknowledge all of the local reliability, market, and supply-related benefits that NOPS would provide. In short, if the Council were to adopt the risky wait-and-see approach that those witnesses advocate, ENO's customers would not receive the benefits of NOPS, but they would be exposed to the risks of high prices on the capacity market and potential cascading power failures.

In response to Dr. Wright's assertions about changes in forecasted customer demand, I disagree that the Company has not explained or disclosed the reasons for the changes.[6] Indeed, in his Supplemental and Amending Direct Testimony, Mr. Cureington specifically addressed the causes of the changes from ENO's prior load forecast to the updated forecast presented with the Company's Supplemental Application. And, as Mr. Cureington now explains in his Rebuttal Testimony, load forecasts will not be perfect in predicting an uncertain future; instead, they are planning tools that are meant to change and respond to different market dynamics. Much like a hurricane model, as conditions change, a load forecast model has to be adjusted with new data to update its forecast. The Company has been forthright with the Council and the parties in this docket concerning its load forecasts, and, when we received an updated forecast in January 2017 that showed a moderation in forecasted peak demand, the Company requested to suspend the proceeding in order to evaluate the best courses of action for its customers. Dr. Wright's suggestions that ENO has withheld information about the forecast moderation and put "a bottom line for profit" above prudent resource planning are incorrect and unsupportable.

[6] Although she presents in her Supplemental Testimony an "analysis of Entergy's new forecast of decreased customer need for electricity," I note that Dr. Wright's Curriculum Vitae does not indicate any experience with utility planning, operations, or load forecasting.

Q10. DO THE ADVISORS' WITNESSES SUPPORT THE POSITION OF THE JOINT INTERVENORS ON THE NEED FOR NOPS?

A. No. The Advisors support the construction of the Alternative Peaker, and their witnesses affirm that the Council should not base its decision in this proceeding solely on economic considerations, but rather should also consider factors such as reliability benefits and transmission constructability.[7] Advisors' witness Mr. Rogers agrees that it would not be appropriate for ENO to rely on the MISO annual Planning Resource Auction ("PRA") to meet long-term resource needs.[8] The Advisors' witnesses also have determined that the solar and wind resource possibilities advocated by the Joint Intervenors will not be able to contribute to ENO's overall reliability or mitigate certain transmission-overload contingencies.[9] And Advisors' witness Mr. Movish discusses numerous benefits that the Alternative Peaker would provide, including:

- operational flexibility;
- dynamic system support for voltage regulation;
- on-site black start capacity to support restoration of service after a major outage or storm event; and
- the ability to provide a source of power to ENO's critical loads in the event of an outage.[10]

The Joint Intervenors have not shown that any of the possibilities mentioned throughout their witnesses' testimonies can provide these benefits in a cost-effective manner. They

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[7] *See* Rogers Direct at 45.

[8] *Id.* at 32.

[9] *See* Movish Direct at 31–34; *see also* Vumbaco Direct at 22.

[10] *See* Movish Direct at 4–5.

simply have not done the analysis. As the Advisors' position confirms, the Alternative Peaker should be viewed as an investment that facilitates rather than competes with DSM and renewable resources, and the Council should reject the Joint Intervenors' wait-and-see approach to meeting the long-term needs that ENO has identified.

Q11. COULD YOU ELABORATE ON WHETHER THE PUBLIC INTEREST WOULD BE SERVED BY ADOPTING THE PASSIVE APPROACH RECOMMENDED BY THE JOINT INTERVENORS?

A. Certainly. The Joint Intervenors' wait-and-see approach is not in the public interest. Our customers are best served when ENO makes prudent, proactive investments in resources that will allow it to continue providing reliable, cost-effective service. Although the Joint Intervenors and several of their witnesses who live in other states may be comfortable with ENO's facing an uncertain future with no generation resources in Orleans Parish, ENO and its customers should not take that gamble, particularly considering ENO's identified need for long-term peaking/reserve resources.

It is important to be mindful of the recent significant changes to ENO's planning and operations that came with the termination of the former Entergy System Agreement and the establishment of an ENO-only Transmission Pricing Zone ("TPZ") in MISO.[11] The Advisors strongly supported the ENO TPZ because they felt it would allow ENO's customers to avoid the subsidization of new investments in utility infrastructure by the other Entergy Operating Companies in Louisiana.[12] The measures taken by the Council

[11] *See* Council Resolution R-15-524.

[12] *See id.* at 8–10.

to avoid subsidizing other utilities caution against ENO's relying on other utilities to make the investments needed to meet ENO's long-term needs. Because ENO's service territory is entirely within the transmission-constrained Downstream of Gypsy ("DSG") sub-region, the Advisors were justifiably concerned about the resulting absence of any generation in the eastern region of ENO upon the retirement of Michoud Units 2 and 3.[13]

In light of this recent history, the weaknesses of the wait-and-see approach advocated by the Joint Intervenors come into sharper focus. ENO has an obligation to serve all current and future load in the City, and it would be irresponsible for ENO to rely on other utilities (both within and outside the DSG load pocket) to make the investments that are needed to serve ENO's customers. Accordingly, as I noted in my Supplemental and Amending Direct Testimony, failing to fill the void in local generation left by the retirement of Michoud Units 2 and 3 is not a long-term solution for ENO and its customers.

Q12. DOES ENO AGREE WITH THE RESULTS OF THE ADVISORS' ADJUSTED ECONOMIC ANALYSES?

A. No. Although the Advisors support the construction of the Alternative Peaker, they also present adjusted economic analyses in the testimonies of Mr. Rogers and Mr. Watson indicating that a transmission-only alternative could be the most economic option to meet ENO's capacity need. But, as Mr. Cureington discusses in his Rebuttal Testimony, the adjustments proposed by Mr. Rogers rest on two flawed assumptions: (1) they use a \$6/kW-year capacity market price for the PRA in MISO Local Resource Zone 9, and (2)

[13] *See id.* at 10, 14.

they decrement ENO's load forecast in line with the Council's 2% DSM goal. Mr. Cureington explains that the extremely low capacity price forecast used by Mr. Rogers (which Mr. Rogers calls a "sensitivity price") relies on the unsupported, best-case assumption that prices will remain essentially flat in real terms over the 20-year planning horizon.

Mr. Cureington also reviews in his Rebuttal Testimony the evidence put forward in his Supplemental and Amending Direct Testimony demonstrating that the Council's 2% DSM goal has not been shown to be achievable, sustainable, or cost-effective over a long-term horizon. The Company's current load forecast (BP17-U) includes reasonable assumptions, including the assumption that historical savings from Company-sponsored energy efficiency programs will continue at the same level, and reflects historical customer behavior, historical voluntary customer efficiency investments, historical performance of customer investments in behind-the-meter technologies (*e.g.,* smart thermostats and rooftop solar), and the use of advanced metering infrastructure ("AMI"). The current load forecast already assumes reductions in future demands, and including additional speculative decrements that may not materialize exposes ENO's customers to the risks of being completely reliant on an overloaded transmission system and the short-term MISO PRA for capacity, which has already demonstrated substantial price spikes from one year to the next.

The expected cost difference between the Alternative Peaker and the transmission-only option is not significant enough to forgo the reliability benefits of local generation, particularly considering the unresolved challenges to the transmission-only approach that are discussed in the testimonies of Mr. Charles Long and Mr. Movish. The challenges with constructing new transmission discussed by Mr. Long and Mr. Movish include issues relating to soil conditions, obstructions, environmental considerations, rights-of-way, and difficulty obtaining necessary outages of transmission lines due to reliability constraints.

IV. COMMUNITY AND ENVIRONMENTAL CONCERNS

Q13. DR. BEVERLY WRIGHT ASSERTS IN HER TESTIMONY THAT NOPS WOULD HAVE ADVERSE EFFECTS ON "THE HEALTH AND GENERAL WELFARE OF NEARBY RESIDENTS."[14] HOW DO YOU RESPOND TO THIS ASSERTION?

A. Dr. Wright's assertion is unsupported and inconsistent with the information and analysis that ENO has provided in support of its Supplemental Application. Importantly, as I discuss further below, there are no residential neighborhoods within one mile of where NOPS will be constructed on the Michoud site, providing a large buffer zone between the facility and nearby residents.

Additionally, as Ms. Higgins has testified, the air emissions from NOPS have pollutant levels that are well below the protective standards set by the EPA, such that neither of the proposed NOPS resources would be expected to "have an adverse impact on the air quality of the area."[15] Her conclusion is supported by the "Technical Report – Evaluation of Groundwater Withdrawal and Air Quality," prepared by C-K Associates, LLC and Losonsky & Associates, Inc. ("C-K Technical Report"), which found that emissions from the CT resource will not "cause air quality to exceed regulatory

[14] Wright Direct at 4.

[15] *See* Higgins Direct at 26.

standards, which are protective of human health and the environment."[16] A supplemental technical report on air quality produced by the same consultants found that the emissions from the RICE units will not "result in ambient air concentrations above air quality regulatory standards, which are protective of human health and the environment."[17]

Furthermore, the analyses and findings of the C-K Technical Report and the testimony of Dr. Losonsky demonstrated that NOPS would have no adverse effect in the area of groundwater withdrawal. The C-K Technical Report found that "[g]roundwater withdrawal at the Michoud Plant is not the cause of observed damage to infrastructure in New Orleans East including buildings, roads, and flood protection structures," and that "[g]roundwater withdrawal associated with [the CT resource] will not exacerbate subsidence or cause damage to infrastructure in New Orleans East."[18] Dr. Losonsky's testimony agrees with this finding and concludes that "1) [t]he groundwater withdrawal associated with the proposed CT unit will not exacerbate subsidence or cause damage to infrastructure in New Orleans East, and 2) [t]he groundwater withdrawal associated with the proposed RICE units will not exacerbate subsidence or cause damage to infrastructure in New Orleans East."[19] Dr. Losonsky also submitted calculations and scientific analyses to support these findings. The accuracy of Dr. Losonsky's underlying calculations has not been challenged by any witness.

[16] Exhibit JEL-6, C-K Technical Report at 5 of 33.

[17] Exhibit JEL-12, Updated C-K Technical Report at 4 of 13.

[18] Exhibit JEL-6 at 5 of 33.

[19] *See* Exhibit GL-2, Addendum to C-K Technical Report at 2.

Q14. HAS ENO MADE A "FALSE STATEMENT," AS ALLEGED BY DR. WRIGHT IN HER SUPPLEMENTAL TESTIMONY,[20] THAT HAS PREVENTED AN ENVIRONMENTAL ASSESSMENT OF NOPS?

A. Absolutely not. Dr. Wright discusses in her testimony a 2003 Environmental Assessment Statement ("EAS") that was filed with the Louisiana Department of Environmental Quality ("LDEQ") concerning a Michoud repowering proposal that was never implemented.[21] Dr. Wright takes issue with the statements that "[t]here are no nearby residential areas" or "schools, hospitals, or other public places in the vicinity of the plant site" that might face a "potential health risk" by proximity to the Michoud units.[22] Those statements were not false when made in 2003, nor would they be false today. The Michoud site is located in a sparsely populated industrial area, and ENO has generated power there for over 50 years. As Ms. Higgins discusses in her Rebuttal Testimony, data from the United States Census Bureau and the EPA indicate that no people live within a one mile radius of the center of the Michoud site. Ms. Higgins further discusses why there is no reason to expect that people living or attending school beyond the one-mile radius of NOPS will experience any adverse health effects because of the proximity of the units.[23]

[20] Wright Supplemental at 7.

[21] Although Dr. Wright contends that the EAS that she attaches to her Supplemental Testimony as Exhibit 1 was submitted to LDEQ in 2004, it actually was submitted in 2003 in connection with an application that had been filed in 2002.

[22] Wright Supplemental at 7.

[23] In her Supplemental Testimony, Dr. Wright warns of "industrial hazards, including the risk of gas explosions." Wright Supplemental at 10. Dr. Wright appears to be referring here to an August 18, 2016 incident concerning a gas line on the Michoud property that she referenced in her Direct Testimony. *See* Wright Direct at 19. This was not an explosion at all, as the workers referenced in Dr. Wright's testimony were involved in removing equipment from service in connection with the decommissioning of a Michoud unit. As Ms. Higgins notes correctly in her Rebuttal

Ms. Higgins also has explained why ENO's air permit application to LDEQ concerning NOPS was appropriate. Nothing that ENO included in the 2003 EAS that Dr. Wright discusses in her Supplemental Testimony is limiting LDEQ's assessment of the application that currently is before the agency, and the Company will continue to provide LDEQ with the information that it requests. The Council and LDEQ each has its own regulatory function in connection with NOPS, and Dr. Wright's inaccurate suggestions about LDEQ applications and processes are neither helpful nor appropriate in this matter before the Council.

Q15. WHAT IS YOUR RESPONSE TO DR. WRIGHT'S TESTIMONY THAT THE PUBLIC HAS HAD INADEQUATE NOTICE OF AND OPPORTUNITY TO PROVIDE INPUT CONCERNING ENO'S 2015 IRP AND ITS PLAN TO CONSTRUCT NOPS? [24]

A. Dr. Wright is simply wrong on this point. As Mr. Cureington details meticulously in his Rebuttal Testimony, the Company's 2015 IRP process and its specific proposal to construct NOPS have provided multiple opportunities for meaningful public participation. As I previously testified, my staff and I have endeavored to keep ENO's customers well informed regarding our plans for NOPS, reaching customers through email and community meetings. Indeed, as Mr. Cureington notes, ENO has held at least **21** public meetings regarding NOPS, and I personally attended most of those meetings.

Testimony, this was an isolated incident that was properly addressed and reported to government agencies. The incident does not call into question whether ENO can safely operate a new NOPS unit at the Michoud site.

[24] *See, e.g.,* Wright Direct at 5; and Wright Supplemental at 2.

In setting the procedural schedule in this docket, the Council also has taken several concrete steps to ensure transparency and public input on whether NOPS should move forward. Specifically, as Mr. Cureington discusses at length, Council Resolutions R-16-506 and R-17-426 have provided interested parties and the public at large substantial notice and opportunity to be heard concerning the Company's NOPS proposal, including public outreach meetings in each Council district and a public hearing in Council Chambers.

Q16. GIVEN THE ENVIRONMENTAL JUSTICE ISSUES RAISED BY DR. WRIGHT, SHOULD THE POSITIVE IMPACTS OF CONSTRUCTING NOPS ALSO BE CONSIDERED?

A. In my opinion, yes. Dr. Wright and Ms. Higgins both have noted that environmental justice is premised on promoting fair treatment and meaningful public involvement. Promoting fair treatment and meaningful public involvement would not be well served if environmental justice concerns were misused to block projects or developments that can bring needed benefits or opportunities to a community. To this point, I attached to my Direct Testimony a report by Loren C. Scott & Associates, Inc., that studied the effects that the construction and operation of the CT resource would have on the economy of Orleans Parish and the State of Louisiana.[25] According to that report, the CT resource would produce significant economic benefits in the form of new business sales, new household earnings, new permanent jobs, and new tax collections, both from its

[25] Exhibit CLR-2.

construction and operation. Those benefits total hundreds of millions of dollars.[26] A recently completed study of the economic impacts of the Alternative Peaker found similar benefits from one-time capital expenditures and even greater benefits than the CT from ongoing operational expenditures that will continue to accrue for as long as NOPS is in operation.[27]

Those benefits would not materialize if the Council accepted Dr. Wright's recommendation that it deny ENO's Supplemental Application. In support of her recommendation, Dr. Wright states that NOPS would "release more pollution into the air,"[28] but, despite mentioning general health concerns, she does not cite to any specific, scientific analysis of how this incremental pollution is likely to affect African American and Vietnamese American communities in New Orleans East. If that approach were sufficient to reach a conclusion of environmental injustice, then much of the recovery and redevelopment in New Orleans East after Hurricane Katrina would fail Dr. Wright's test of environmental justice. After all, rebuilding and occupying homes, schools, churches, grocery stores, and businesses bring some level of incremental pollution. That is why it is important to consider the objective, scientific standards set forth in the analyses presented by ENO when assessing the nature and extent of potential adverse impacts of a project.

[26] *Id.* at 15–16 of 16.

[27] Exhibit CLR-3.

[28] Wright Direct at 17.

Q17. DR. WRIGHT TESTIFIES THAT NOPS WOULD HAVE A RACIALLY DISCRIMINATORY EFFECT.[29] WHAT IS YOUR RESPONSE TO THAT TESTIMONY?

A. As a native New Orleanian with friends and colleagues who live in New Orleans East, I find it offensive. ENO is an essential part of this community, and it provides opportunities to people of all races and walks of life. Moreover, ENO's corporate parent, Entergy Corporation, is the only Fortune 300 Company headquartered in New Orleans. Leaders on the frontlines of providing educational opportunities and outreach to the poor and disadvantaged in our community know that has Entergy has been an unfailing partner in their efforts. Indeed, many community leaders and citizens from New Orleans East appeared in the Council Chambers at the October 16, 2017 public hearing in this docket and expressed appreciation for Entergy's support. In pointing this out, I do not suggest that the Council should approve NOPS simply because Entergy has been a good community partner and corporate citizen (in fact, it has been).[30] What I am saying, however, is that Dr. Wright and the Joint Intervenors go too far by suggesting that ENO's NOPS proposal is discriminatory. To be clear, NOPS will benefit *all* citizens of New Orleans, but not at the disproportionate expense of any group of citizens.

As shown by the technical reports and testimony of experts testifying on behalf of ENO, Dr. Wright's contrary conclusion is not supported by any scientific analysis of the expected impact of NOPS. Dr. Wright cites nothing that indicates a racially

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[29] *See* Wright Direct at 22; and Wright Supplemental at 2.

[30] Entergy employs 2,500 employees locally, paid $56 million in local taxes in 2016, invested over $6 million in almost 300 nonprofits that serve Orleans Parish, and is part of a five-year, $5 million workforce development initiative. Entergy's supportive efforts were recently noted in connection with the announcement that DXC Technology plans to bring 2,000 new jobs to New Orleans. *See* http://www.nola.com/business/index.ssf/2017/11/tech_company_new_orleans_dxc.html.

discriminatory intent on ENO's part in the planning for NOPS, and the three reasons she provides to explain her conclusion that NOPS would have a "racially discriminatory effect on predominantly African American and Vietnamese American residents living in New Orleans East"[31] do not support that conclusion.

First, ENO's resource planning process that identified the need for NOPS proceeded under guidelines set by the Council itself, and the Council has recognized the potential importance of constructing new generation in Orleans Parish.[32] There were multiple opportunities for public participation in the planning process, and ENO has continued its dialogue with stakeholders on the plans for NOPS.

Second, Dr. Wright gives an incorrect impression of the population that resides within a mile of the Michoud site. The site is in a sparsely populated industrial area where ENO operated a power plant for decades. Furthermore, the air emissions from NOPS will not exceed regulatory standards that have been put in place to safeguard human health and the environment and will be less than the retired Michoud units. Dr. Wright's suggestions of serious potential health risks are unsupported.

And third, Dr. Wright has not shown that ENO's applications for certain environmental permits were improper, particularly in light of the prior use of the Michoud site. Moreover, LDEQ has actually implemented opportunities for public participation in its review of ENO's application, and its proceedings are ongoing. Again, Dr. Wright's misstatements concerning filings with LDEQ are not helpful to the Council's consideration of the Company's Supplemental Application.

[31] Wright Direct at 22.

[32] *See* Council Resolution R-15-524, at 12.

In summary, none of Dr. Wright's observations support her conclusion that NOPS would have a racially discriminatory effect. In our modern society, electric service is viewed as essential by most people, and the African American and Vietnamese American residents of New Orleans East will continue to benefit from ENO's being able to provide that service. Furthermore, the Council has determined correctly that there may be benefits to having a power plant in Orleans Parish, and the testimony and exhibits submitted with ENO's Supplemental Application demonstrate that the Michoud site is an appropriate location that will not have significant negative health or environmental impacts. Under these circumstances, Dr. Wright's recommendation that ENO's Supplemental Application be denied is not consistent with environmental justice principles.

V. COST RECOVERY AND OTHER ISSUES

Q18. WHAT IS THE COMPANY'S RESPONSE TO THE TESTIMONIES OF THE ADVISORS AND AIR PRODUCTS CONCERNING THE COST RECOVERY PLAN FOR NOPS?

A. Ms. Lovorn-Marriage sets forth the Company's full response in her Rebuttal Testimony, but I must take the opportunity to emphasize the importance of timely cost recovery to the Company's plan to construct NOPS. As Company witness Orlando Todd explained in his prior testimonies in this docket, once a project like NOPS commences commercial operation, ENO will begin incurring costs that are not expected to be reflected in ENO's base rates until the project is placed in service. If the Council takes no action to allow for contemporaneous in-service recovery of those costs, there would be significant adverse effects on ENO's financial condition. For a company of ENO's size, prolonged regulatory lag on recovery of a substantial investment like NOPS could severely limit the Company's ability to make other required investments and respond to emergency conditions. Simply put, for ENO to undertake the construction of the first new generation in the City in over forty years, the Company must have assurances of a reasonable opportunity to recover timely its investment and its allowed return on investment. Accordingly, in an order approving the construction of NOPS, the Company is requesting that the Council authorize specific alternatives that provide such assurances.

Q19. DO YOU HAVE A RESPONSE TO DR. STANTON'S TESTIMONY THAT ELECTRIC CUSTOMERS IN NEW ORLEANS FACE HIGH COSTS IN COMPARISON TO OTHER U.S. CITIES?

A. Yes. Dr. Stanton's testimony on this point is misleading and incorrect. She bases her conclusion on a report that compares utility costs as a share of median household gross income and not on an apples-to-apples comparison of utility costs among American cities. Although, as I previously discussed, the construction of NOPS would bring significant benefits to the local economy, it is improper to evaluate ENO's rates based only on current average local income levels in the City of New Orleans. According to 2016 data from the United States Department of Energy's Energy Information Administration, ENO's residential customers' bills are among the lowest in the Southeastern United States: of the 29 utilities evaluated, only four utilities had lower average monthly electricity bills for residential customers.[33] That same data show that

[33] *See* Exhibit CLR-4.

only two of the 29 utilities had usage levels that are less than ENO's customers.[34] Accordingly, if ENO's customers' energy costs are relatively high as a percentage of household income compared to other cities, it is the relatively low average household income in New Orleans that is driving the relatively high percentage, not the electricity rates or usage levels of our residential customers.

Many of Entergy's charitable contributions support organizations that serve lower-income citizens and assist in poverty solutions. Accordingly, although median household gross income in the City is not within ENO's direct control, the Company makes tangible contributions to improving the City's economy and creating better opportunities for its citizens. And, again, constructing NOPS will have a beneficial effect on the City's economy.

Q20. DR. STANTON QUESTIONS HOW INVESTMENTS IN DISTRIBUTION UPGRADES IMPACT ENO'S NEED FOR NEW CAPACITY. HOW DO YOU RESPOND TO THAT QUESTION?

A. Dr. Stanton notes correctly that distribution upgrades will not fill ENO's capacity deficit. But any suggestion in her testimony that prevention of distribution outages is the "centerpiece" of ENO's rationale for constructing NOPS is incorrect. Mr. Charles Long explains in his Rebuttal Testimony why distribution outage mitigation is a separate issue from the need for NOPS that has been established in the Company's Supplemental Application. On November 10, 2017, ENO filed with the Council the Company's Reliability Plan pursuant to Council Resolution R-17-427, and that plan set forth

[34] *Id.*

descriptions and budget information for six major programs that are focused on improving the reliability of the Company's distribution system. Those programs and other reliability initiatives do not in any way undermine the Company's need to construct NOPS.

VI. CONCLUSION

Q21. BASED ON YOUR REVIEW OF THE TESTIMONY OF THE ADVISORS AND INTERVENORS, HAS ENO ALTERED ITS CONCLUSION ABOUT WHETHER CONSTRUCTING NOPS WILL SERVE THE PUBLIC INTEREST?

A. No. As shown in ENO's testimony, both the CT and the Alternative Peaker have significant benefits. Forecasts show that ENO has a need for additional peaking capacity in order to meet future load. Either plant would be able to meet that need while providing the City of New Orleans with a long-term resource that will improve supply conditions and support reliable service to the City during periods of peak demand and unplanned events, and either will mitigate market and supply-related risks. Either plant will have the effect of eliminating the risk of cascading outages in New Orleans and the ability to provide reliability benefits such as support for restoration efforts following major weather events.

In addition to providing an efficient, modern generating unit that can contribute to meeting the City's reliability needs, construction and operation of NOPS will lead to significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the Orleans Parish and State economies. These economic benefits would not arise were the Council to deny ENO's

Supplemental Application for NOPS. And these benefits will not come at the expense of the environment or the community in New Orleans East. The Company's witnesses have shown that NOPS will not adversely affect public health or the environment.

In short, customers face a possibility of harm if the Council were to delay or deny certification of NOPS, as requested by the Joint Intervenors. Because NOPS would serve the public interest, ENO respectfully requests that the Council approve its Supplemental Application and certify construction of either the CT or the Alternative Peaker.

Q22. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES L. RICE, JR.**, who after being duly sworn by me, did depose and say:

That the above and 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.

Charles L. Rice, Jr.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 28th DAY OF NOVEMBER, 2017

NOTARY PUBLIC

My commission expires: at death

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

ECONOMIC IMPACT ON THE ORLEANS PARISH AND LOUISIANA ECONOMIES OF ENTERGY'S PROPOSED NEW ORLEANS POWER STATION

PREPARED BY

LOREN C. SCOTT & ASSOCIATES, INC.

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October 2017

Executive Summary

Entergy New Orleans, Inc. ("ENOI") plans to construct a new power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana is located. The company is proposing to install seven reciprocating internal combustion engines (RICE) and ancillary equipment. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 128 megawatt (MW). The proposed RICE project will be connected to a new switchyard with new 115-kilovolt (kv) main bus in a simple bus configuration to support one 115-kv transmission line position and three 115-kv line terminations coming from three Generator Step Up (GSU)transformers.

The purpose of this report is to estimate the impact of constructing and then operating this new plant on the (1) Orleans Parish and (2) State of Louisiana economies, using input-output tables produced by the U.S. Bureau of Economic Analysis. Our findings can be summarized as follows:

The impacts of spending $134.2 million in-state to both **plan** (2015-17) and **construct** (2018-20) the NOPS are:

- Impacts on **Orleans Parish** economy:
  - $180,230,600 in new sales at companies in the parish;
  - $24,612,280 in new earnings for parish residents;
  - An average of 80 jobs a year, and;
  - $861,430 in new sales tax collections for the parish treasury.
- Impacts on the **Louisiana** economy:
  - $266,427,260 in new sales at companies in the state;
  - $89,726,120 in new earnings for state residents;
  - An average of 306 jobs a year in the state, and;
  - $6,280,828 in new revenue collections for the state treasury.

Table E-1 summarizes the annual impacts on the parish and state economies of **operating** this plant once it is built. While the construction impacts bulleted above are temporary and vanish once construction ends, the impacts in Table E-1 are on-going and indeed, will likely grow over time due to inflation.

Table E-1
Impacts of Operating the NOPS on the Orleans Parish & Louisiana Economies

Category	Orleans Parish Impacts	State Impacts
New Business Sales	$12,778,008	$18,961,224
New Household Earnings	$5,974,928	$10,385,789
New Permanent Jobs	59	153
Taxes	$209,122	$727,005

Table of Contents

I. Introduction

Entergy New Orleans, Inc. ("ENOI") plans to construct a new power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana is located. The company is proposing to install seven reciprocating internal combustion engines (RICE) and ancillary equipment. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 128 megawatt (MW). The proposed RICE project will be connected to a new switchyard with new 115-kilovolt (kv) main bus in a simple bus configuration to support one 115-kv transmission line position and three 115-kv line terminations coming from three Generator Step Up (GSU) transformers.

Expenditures on planning the construction will occur over 2015-17 and actual construction will take place over 2018-20. The middle column of Table 1 shows the pattern of these expenditures over these six years. Of the total construction cost of $210.0 million, it is estimated that $75.8 million will be spent on equipment and materials purchased out-of-state. The last column of Table 1 shows the in-state expenditures after deducting this $75.8 million. The total in-state construction spending will be $134.2 million.

Table 1
Schedule for Construction of the New Orleans Power Station
(Millions of Dollars)

Year	Total Construction Cost	In-State Construction Spending
2015	$1.6	$1.6
2016	$2.5	$2.5
2017	$8.3	$8.3
2018	$107.7	$58.4
2019	$77.3	$57.8
2020	$12.6	$5.6
Total	**$210.0**	**$134.2**

This report is focused on estimating the impact of both constructing and operating the NOPS on the economies of Orleans Parish and the State of Louisiana. In each region impacts will be estimated on (1) business sales, (2) household earnings, (3) jobs, and (4) tax collections. Section II describes the methodology used to estimate the multiplier effect of this new spending. Section III is devoted to the impacts of constructing and operating the NOPS on the Orleans Parish economy, while Section IV examines the impact of this spending on the State's economy. Finally, Section V contains a summary and conclusions.

II. Methodology

It is a well-established principle that business investment decisions have both direct and indirect (secondary) impacts on the economy. The direct impact of a particular company or establishment on income and employment can be measured by its revenue and payroll. However, these impacts would significantly understate the role of the company in the economy. The reason is that the company also buys from, and sells to, many other companies in the economy. The interactions caused by these purchases and expenditures are magnified by the spending of employees who earn income from the company and the affected businesses.

Thus, any change in the activity of a particular company **indirectly** affects these buyers and sellers, which in turn affects companies that buy from and sell to these buyers and sellers, etc. For example, when a decision is made by a company that creates a new job, a chain-reaction is started which works its way throughout the economy. This chain-reaction (multiplier effect) causes even more jobs to be created. The analogy is of a rock being tossed into a pond. Not only is there an initial splash, but ripples are also created that spread throughout the pond.

The major difficulty lies in attempting to quantify these indirect or multiplier effects. Fortunately, a technique has been developed for precisely this purpose---an input-output (I/O) table. An I/O table is a matrix of numbers that describes the interactions between all industries in a geographical area (in this case, the state and the region). The I/O table provides a complete picture of the flows of products and services in the economy for a given year, illustrating the relationship between producers and consumers and the interdependencies of industries in the state. I/O tables for Orleans Parish and the State of Louisiana have been constructed by the Bureau of Economic Analysis (BEA) in the U.S. Department of Commerce. The BEA is the government agency responsible for measuring the nation's gross domestic product each quarter. An I/O table can be used to estimate three separate impacts generated by the capital outlays and operational expenditures by ENOI on the NOPS: (1) *new sales* for companies in the parish and the state, (2) *new household earnings* for residents in the parish and the state, and (3) *new jobs* in the parish and the state.

III. Impact of NOPS Capital & Operational Spending on Orleans Parish

In this section the impact of the new NOPS project is assessed on the economy of Orleans Parish. The impact of constructing the facility is discussed first, followed by the impact of operating the plant once construction is completed.

Impact of Constructing the NOPS on Orleans Parish

As shown in Table 1, the NOPS will be planned and constructed over the 6-year period from 2015 to 2020. The last column of that table shows how the total of $134.2 million of in-state spending will be allocated over the six years. The majority of this in-state spending will occur over 2018-19, with the peak spending year being 2018 ($58.4 million).

These in-state construction data were plugged into the I/O table for Orleans Parish to determine the multiplier effects of this spending on the parish's economy. The results are shown in Table 2.

Table 2
Impacts of Planning & Construction of the NOPS on Orleans Parish

Years	Sales	Earnings	Jobs	Taxes
2015	$2,148,800	$293,440	6	$10,270
2016	$3,357,500	$458,500	9	$16,048
2017	$11,146,900	$1,522,220	30	$53,278
2018	$78,431,200	$10,710,560	209	$374,870
2019	$77,625,400	$10,600,520	205	$371,018
2020	$7,520,800	$1,027,040	20	$35,946
Total	**$180,230,600**	**$24,612,280**	**80***	**$861,430**

*Average over 5-year construction cycle

According to the parish I/O table, spending to plan and construct the NOPS over 2015-20 will create (1) $180.2 million in new business sales in the parish, (2) $24.6 million in new household earnings for parish residents, and (3) an average of 80 jobs a year. Not surprisingly, the largest impacts are in the years of greatest construction spending---2018 and 2019. In the peak year of spending (2018), construction activity will create $78.4 million in new business sales in the parish and $10.7 million in new household earnings for parish residents and 209 temporary jobs parish.

It is also possible to estimate how much new sales taxes the parish will collect due to the planning and construction of the NOPS. For example, in 2012 the parish collected just over $324 million in sales tax collections.[1] In that same year parish residents made $9,745.2 million in earnings.[2] Thus, it is estimated that for every dollar of earnings, the parish collects 3.5 cents ($324 million/$9,745.2 million) in sales taxes.

[1] www.nola.gov/revenue-sales-tax/sales-tax/
[2] www.bea.gov

By multiplying the new earnings numbers in column two of Table 2 by 3.5% we arrive at the new sales tax estimates in the last column of Table 2. **It is estimated that the planning and construction of the NOPS will pump an additional $861,430 in new sales taxes into the parish treasury**.

Impact of Operating the NOPS on Orleans Parish

Once the NOPS construction is completed, new monies will be injected into the parish economy to operate the plant. ENOI estimates it will spend just under $6.6 million a year to operate the facility. Of this $6.6 million, over $3.6 million will be spent on payroll. The new plant is expected to employ 20 new full time employees.

Table 3 provides the I/O table estimates of the total impact on the parish of the new operating expenditures. **It is estimated that operating the NOPS will generate (1) nearly $12.8 million in new sales for businesses in the parish, (2) about $6 million in new earnings for parish residents, (3) 59 new permanent jobs in the parish, and (4) $209,122 a year in new sales tax collections for the parish treasury**. There are two important points to note about the numbers in Table 3. First, unlike the construction benefits documented in Table 2 which will vanish once construction is completed, the benefits in Table 3 are recurring or permanent as long as the NOPS remains operational. Secondly, the sales, earnings and sales tax numbers in Table 3 will tend to grow over time with inflation.

Table 3
Impacts of Operations of the NOPS on Orleans Parish: First Year of Operation

Category	Impacts
New Business Sales	$12,778,008
New Household Earnings	$5,974,928
New Permanent Jobs	59
Taxes	$209,122

Operational Impacts on Industries in the Parish

Decision-makers may be interested in how the indirect (multiplier) effects of operating the NOPS are allocated among all the industries in the parish. Table 4 provides the I/O table estimates of this distribution.

Table 4
Indirect Impacts of NOPS Operations Spending on Orleans Parish by Industry: First Year of Operation

Category	Sales	Earnings	Jobs
Agriculture, Forestry, Fishing, and Hunting	$0	$0	0
Mining	$123,902	$7,428	0
Utilities	$83,077	$5,579	0
Construction	$6,606,222	$921,015	15
Durable Goods Manufacturing	$298,830	$15,457	0
Nondurable Goods Manufacturing	$788,152	$48,014	1
Wholesale Trade	$252,451	$31,056	0
Retail Trade	$588,709	$101,475	4
Transportation and Warehousing	$211,075	$23,140	0
Information	$122,661	$15,002	0
Finance and Insurance	$517,194	$55,413	1
Real Estate and Rental and Leasing	$942,628	$83,911	4
Professional, Scientific, and Technical Services	$403,056	$91,255	1
Management of Companies and Enterprises	$90,789	$14,834	0
Administrative and Waste Management Services	$145,312	$28,385	1
Educational Services	$103,142	$28,698	1
Health Care and Social Assistance	$537,649	$108,543	3
Arts, Entertainment, and Recreation	$72,961	$13,964	1
Accommodation	$93,417	$14,956	0
Food Services and Drinking Places	$229,919	$44,265	2
Other Services	$567,258	$89,416	2
Households	$0	$4,558	0
Total	**$12,778,404**	**$1,746,363**	**39**

The industry that gains the most sales increase from the operation of the power station is the construction sector. Companies in this sector should see their sales increase by $6.6 million due to the NOPS operations. Companies in six other industries should see their sales increase in excess of $500,000: (1) Nondurable Goods ($788,152); (2) Retail Trade ($588,709); (3) Finance and Insurance ($517,194); (4) Real Estate and Rentals ($942,628); (5) Health Care ($537,649); and (6) Other Services ($567,258).

Note in column two of Table 4 that it will be workers in the construction industry that will receive the largest increase in household earnings ($921,015), followed by workers in the Health Care ($108,543) and Retail Trade ($101,475). Thirty nine jobs will be created via the multiplier effect.

IV. Impact of NOPS Capital & Operational Spending on Louisiana

In this section of the report, the impact of both planning/constructing and operating the new NOPS on the state economy is examined. Note that all the impact results should be larger than in the case of the parish impacts, because the economic "pond" into which this new unit will be dropped is much larger.

Impact of Constructing the NOPS on Louisiana

Table 5 contains the I/O table estimates of the impact of planning and constructing the new NOPS on the Louisiana economy. Again, these numbers are noticeably larger than those in Table 2 because the economic pond is now larger and the ripple effects of the spending reaches further into the economy.

Over the 6-year planning/construction cycle it is estimated this capital spending will create (1) over $266.4 million in new sales at businesses in Louisiana, (2) over $89.7 million in household earnings for citizens of the state, and (3) an average of 306 jobs a year. Impacts are the greatest in the years of the greatest construction spending---2018-19. In the year of the largest spending (2018), construction spending at the site will generate (1) over $115.9

million in new business sales, (2) over $39.0 million in new household earnings, and (3) 803 jobs.

Table 5
Impacts of Planning & Constructing the NOPS on the Louisiana Economy

Years	Sales	Earnings	Jobs	Taxes
2015	$3,176,480	$1,069,760	23	$74,883
2016	$4,963,250	$1,671,500	35	$117,005
2017	$16,477,990	$5,549,380	115	$388,457
2018	$115,941,520	$39,046,240	803	$2,733,237
2019	$114,750,340	$38,645,080	787	$2,705,156
2020	$11,117,680	$3,744,160	75	$262,091
Total	**$266,427,260**	**$89,726,120**	**306***	**$6,280,828**

*Average yearly jobs created.

The last column of Table 5 provides estimates of the impact of building this plant on state revenues. Officials with Louisiana's Legislative Fiscal Office have estimated that for every new dollar of earnings generated in the state, the treasury collects seven cents in sales taxes, income taxes, gasoline taxes and other fees. The numbers in the last column of Table 5 are produced by multiplying the earnings figures in column two by 7%. Using this calculus, it is estimated that **over the 6-year planning/construction cycle, almost $6.3 million in new revenues will be generated for the state treasury**.

Impacts of Operating the NOPS on the Louisiana Economy

The benefits to the state from the construction of the NOPS project are temporary as shown in Table 5. That is, as soon as construction is completed, these benefits go away. This is not the case for the benefits from operating the plant, which are shown in Table 6. As long as the plant remains operational, the benefits shown in Table 6 below will accrue to Louisiana. In fact, the sales, earnings and tax benefits are very likely to grow with inflation.

Table 6
Impacts of Operating the NOPS on the Louisiana Economy

Category	Impacts
New Business Sales	$18,961,224
New Household Earnings	$10,385,789
New Permanent Jobs	153
Taxes	$727,005

According to the I/O table, **operation of the new NOPS facility will annually support (1) nearly $19 million in new sales at businesses in the state, (2) nearly $10.4 million in new household earnings for state citizens, (3) 153 new jobs, and (4) $727,005 in new revenues for the state treasury.** The 153 new jobs in the state implies a job multiplier of 7.7 (153 total jobs divided by 20 direct jobs at the NOPS). That is, for every new job created at the facility, another 6.7 jobs are created elsewhere in Louisiana via the multiplier effect.

Operations Impacts across Industries in Louisiana

Readers may be interested in learning in which industries are these multiplier effects concentrated. Table 7 provides estimates from the Louisiana I/O table. The biggest **sales** increases are projected for companies in the construction sector ($6.7 million) followed by companies in the nondurable goods manufacturing sector ($1.7 million), retail trade ($1.3 million) and healthcare ($1.3 million).

Table 7
Indirect Impacts of Operating the NOPS
on Louisiana by Industry: 2020

Category	Sales	Earnings	Jobs
Agriculture, Forestry, Fishing, and Hunting	$100,507	$26,605	1
Mining	$273,406	$46,674	1
Utilities	$343,790	$52,433	1
Construction	$6,682,167	$2,573,489	43
Durable Goods Manufacturing	$1,002,161	$202,536	4
Nondurable Goods Manufacturing	$1,658,642	$256,061	3
Wholesale Trade	$766,539	$242,864	4
Retail Trade	$1,348,136	$481,101	16
Transportation and Warehousing	$566,037	$172,439	3
Information	$343,839	$74,032	1
Finance and Insurance	$667,178	$174,112	4
Real Estate and Rental and Leasing	$1,207,976	$200,359	8
Professional, Scientific, and Technical Services	$554,494	$248,825	4
Management of Companies and Enterprises	$159,635	$66,921	1
Administrative and Waste Management Services	$290,688	$126,102	4
Educational Services	$155,077	$72,508	2
Health Care and Social Assistance	$1,312,426	$601,688	13
Arts, Entertainment, and Recreation	$121,287	$36,554	1
Accommodation	$159,796	$44,998	1
Food Services and Drinking Places	$427,687	$138,825	7
Other Services	$819,340	$303,698	8
Households	$0	$14,465	1
Total	**$18,960,808**	**$6,157,290**	**133**

When it comes to **household earnings**, it is workers in the construction sector that have the most to gain---almost $2.6 million. Over $300,000 in new earnings will be enjoyed by workers in Health Care ($601,688), Retail Trade ($481,101), and Other Services ($303,698). One hundred thirty three **jobs** will be created via the multiplier effect (Table 7).

V. Summary & Conclusions

Entergy New Orleans, Inc. ("ENOI") plans to construct a new power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana is located. The company is proposing to install seven reciprocating internal combustion engines (RICE) and ancillary equipment. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 128 megawatt (MW). The proposed RICE project will be connected to a new switchyard with new 115-kilovolt (kv) main bus in a simple bus configuration to support one 115-kv transmission line position and three 115-kvline terminations coming from three Generator Step Up (GSU) transformers.

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Taxes	$209,122	$727,005

U.S. Department of Energy's Data on Regional Bills and Usage in 2016

Regional Utilities' 2016 Average Bills and Usage

Electric Utility	Average Bill	Rank	Average kWh/Mo	Rank
SCE&G (SC)	$163	1	1,120	16
Alabama Power	$154	2	1,214	7
Gulf Power (FL)	$150	3	1,126	15
Cleco Power	$143	4	1,259	3
Mississippi Power	$142	5	1,115	18
Tampa Electric (FL)	$134	6	1,185	9
Jackson EMC (GA)	$131	7	1,275	1
Duke Energy Florida	$130	8	1,084	24
Appalachian Power (VA)	$129	9	1,140	12
City of Nashville (TN)	$129	10	1,161	10
Georgia Power	$129	11	1,072	26
Cobb EMC (GA)	$128	12	1,224	6
City of Jacksonville (FL)	$124	13	1,119	17
Virginia Power	$123	14	1,099	22
Regional Average	**$123**	**---**	**1,128**	**---**
Duke Energy Progress (NC)	$123	15	1,138	13
Entergy Texas	$123	16	1,266	2
City of San Antonio (TX)	$120	17	1,114	19
Florida Power & Light	$116	18	1,146	11
Duke Energy (NC/SC)	$116	19	1,101	21
City of Memphis (TN)	$115	20	1,211	8
Oklahoma Gas & Electric	$114	21	1,091	23
Entergy Arkansas	$111	22	1,077	25
SWEPCO (AR/LA/TX)	$109	23	1,136	14
Entergy Louisiana	$107	24	1,249	5
Entergy New Orleans	**$106**	**25**	**1,045**	**27**
Entergy Mississippi	$102	26	1,252	4
Public Service Co of OK	$95	27	1,104	20
Xcel SPS (TX)	$95	28	944	28
El Paso Electric (TX)	$79	29	640	29

Source: U.S. Department of Energy, Energy Information Administration; EIA Form 826

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	))))))	**DOCKET NO. UD-16-02**

REBUTTAL TESTIMONY

OF

SETH E. CUREINGTON

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

NOVEMBER 2017

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Seth E. Cureington. My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. ARE YOU THE SAME SETH E. CUREINGTON WHO FILED DIRECT TESTIMONY (JUNE 2016), SUPPLEMENTAL DIRECT TESTIMONY (NOVEMBER 2016) AND SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY (JULY 2017) IN THIS DOCKET?

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, Inc. ("ENO").

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain arguments, positions, and recommendations made by the Council's Advisors ("Advisors"), and separately, Dr. Elizabeth Stanton and Mr. Robert Fagan, who are testifying on behalf of Sierra Club, Deep South Center for Environmental Justice, the Alliance for Affordable Energy, and 350 Louisiana – New Orleans (I will refer to those groups for whom Mr. Fagan and Dr. Stanton are testifying collectively as the "Joint Intervenors"). I also respond to a few of the issues raised by Joint Intervenors witness Dr. Beverly Wright and Air Products and Chemicals, Inc. ("Air Products") witness Maurice Brubaker. The Advisors, Joint Intervenors, and Air Products filed their Direct Testimony in response to the Company's Supplemental and Amending Application ("Supplemental Application") in this proceeding. The Supplemental Application seeks, among other things, approval to construct the New Orleans Power Station ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 MW or, alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator Sets ("Alternative Peaker") with a summer capacity of 128 MW.

Q5. DO YOU HAVE A GENERAL REACTION TO THE ISSUES RAISED BY THE JOINT INTERVENORS?

A. Yes. In opposing NOPS, Joint Intervenors witnesses Stanton and Fagan offer a string of unsupported assumptions citing to macro-level information not specific to ENO, its service area, or the Company's unique planning circumstances, and which assumptions reflect extremely optimistic, best case scenarios more appropriate for consideration in an integrated resource planning ("IRP") process. Importantly, they provide no real alternative plan and have not conducted any analysis of the total combined costs and benefits of the various alternatives that they recommend. Their purported alternatives also demonstrate a lack of understanding of ENO's unique planning circumstances, focusing almost exclusively on hypothetical alternatives for meeting an overall capacity need, while ignoring the other benefits of NOPS and assuming that the Midcontinent Independent System Operator, Inc. ("MISO") short-term capacity market will take care of everything else. In the process, the Joint Intervenors witnesses give no consideration to the recent history before this Council that supports the conclusion that NOPS is the best option to meet the identified need and address the Company's unique planning circumstances.[1] Further, they fail to acknowledge all of the local reliability, market-, and supply-related benefits NOPS would provide in addition to addressing the Company's projected long-term capacity need.

If the Joint Intervenors witnesses' positions were adopted, but their speculative and optimistic assumptions about MISO's future capacity position, the effectiveness of demand-side management ("DSM"), and growth in behind-the-meter solar proved to be wrong, the Company would find itself in need of capacity and reliant on the short-term MISO capacity market at a time when market prices are projected to be substantially increasing. The Company would also be without a hedge against higher Locational Marginal Prices ("LMPs") in the New Orleans Load Zone and potentially facing North American Electric Reliability Corporation ("NERC") violations given the constructability issues associated with transmission upgrades that would be necessary absent NOPS, as discussed by Mr. Charles Long. On the other hand, if the Company's position is adopted, but load or deactivations are less than projected, NOPS would still be a reasonable long-term resource addition considering ENO's unique planning circumstances.

[1] For example, the deactivation of Michoud Units 2 and 3, early termination of the System Agreement, and the Final 2015 Integrated Resource Plan.

Moreover, ENO is the party with the obligation to serve whatever load actually materializes in the future, and it is well recognized that a utility's total capacity and resource needs will never line up exactly. Additionally, constructing NOPS will provide the following benefits:

1) avoid transmission upgrades for which the cost and time to construct are uncertain;

2) provide a local resource to ensure the Company supports reliability in the Downstream of Gypsy ("DSG") load pocket, in which 100% of its load is located;

3) provide a unit capable of backing up renewable resources and supporting grid resiliency;

4) facilitate load-serving capability and system restoration following extreme weather (*e.g.*, hurricanes and tornadoes);

5) provide a hedge against congestion on the transmission system that tends to increase LMPs in the New Orleans Load Zone;

6) facilitate planned transmission and generation maintenance outages in the load pocket and mitigate the risk associated with unplanned outages; and

7) provide a quick-start, fast ramping resource capable of responding to real-time operational needs of the ENO system.

The Joint Intervenors witnesses also testify as if ENO has completely rejected the notion of including DSM and renewable resources in its portfolio. To the contrary, as discussed in my Direct and Supplemental and Amending Direct Testimonies, ENO's forecast incorporates a reasonable level of DSM consistent with the savings levels actually achieved to date by ENO's Energy Smart programs, and it continues to pursue implementation of additional DSM consistent with the Council's DSM goal as identified in the Company's recent Implementation Plan filing.[2] ENO has filed an application for approval to implement advanced metering infrastructure ("AMI"), and it has included the projected effects of AMI in the current load forecast (BP17-U). ENO has also included 100 MW of solar among its portfolio of planned resource additions.[3] In sum, ENO has incorporated resources into its long-term plans that the Joint Intervenors witnesses claim the Company is ignoring, but in a measured approach consistent with its obligation to serve load and engage in a prudent long-term planning process that strives for a balanced resource portfolio. To adopt more aggressive assumptions would constitute unreasonable speculation and expose customers to unreasonable risk.

It is not seriously disputed that ENO has a need for capacity, and in fact the Joint Intervenors witnesses simply argue in favor of a more speculative and risky wait-and-see approach to meeting the long-term need that ENO has identified. For example, instead of taking steps to protect customers from an inefficient short-term capacity market where MISO has projected that supply will be less than demand by 2023, the Joint Intervenors witnesses have stated that ENO should "exploit" the market by waiting for other utilities to build generation to keep that price low.[4] In

[2] Filed February 13, 2017, in Council Docket UD-08-02.

[3] To that end, ENO conducted a request for proposals ("RFP") in 2016 and selected three solar resources totaling 45 MW. On October 6, 2017, ENO filed for approval at the Council to implement one of the three solar projects selected in the RFP; namely, a 5 MW project involving ENO owning and operating commercial-scale rooftop solar systems in the City.

[4] Fagan Direct at 31.

other words, they advocate that ENO simply hope that other utilities act responsibly to address their long-term needs and by doing so somehow provide surplus capacity to the market for ENO to "exploit."

In addition, it is also undisputed that by acting to address a portion of the substantial need for a long-term source of local peaking and reserve capacity, the Company has also demonstrated the reliability and risk-mitigation benefits of constructing fast-start, dispatchable capacity in New Orleans. Further, the economic analysis presented in my Supplemental and Amending Direct Testimony, which included some of the alternatives suggested by the Joint Intervenors witnesses, demonstrates that NOPS is among the lowest-cost resources capable of meeting the Company's projected need, considering reliability and risk. On the other hand, the Joint Intervenors witnesses do not put forth any credible evidence or analysis that their extremely optimistic and speculative alternatives would meet the identified needs at a lower cost or over a time frame that would avoid the necessary transmission upgrades (as discussed by Mr. Charles Long), or provide a comparable level of reliability and risk mitigation.

Finally, NOPS is not the end of the road for ENO's long-term resource planning as the Joint Intervenors witnesses would have the Council believe. Resource planning is an ongoing process that constantly evaluates the Company's needs and new technology. Given recent history with the retirement of Michoud Units 2 and 3, it is possible some of the older remaining units in the Company's portfolio could deactivate earlier than expected and/or new technology such as electric vehicles could increase load, which in turn could provide additional need for new resources. What is not reasonable is adopting the Joint Intervenors witnesses' speculative approach for addressing a current long-term need for local peaking capacity despite extensive analysis that shows NOPS is the best alternative to meet that need at the lowest reasonable cost considering risk.

Q6. DO YOU HAVE A GENERAL REACTION TO THE RECOMMENDATIONS OF THE ADVISORS?

A. Yes. While it was encouraging that the Advisors recommend the Council approve the RICE Alternative for NOPS, I note that in their assessment of the Company's economic analysis, Advisors witnesses Joseph W. Rogers and Byron S. Watson produced revised economic analyses based on replacing assumptions in the Company's models with assumptions recommended by Mr. Rogers. Much of Mr. Rogers's testimony describes and acknowledges a number of changes that have occurred since the 2015 IRP that affect the Company's planning circumstances; however, what has not changed is the need for a local source of peaking and reserve capacity and the inability of DSM and renewable resources to meet that long-term need. Despite this fact, similar to the Joint Intervenors, Mr. Rogers seeks to alter the Company's reasonable assumptions, including adopting the assumption that the Council's 2% DSM goal is achievable and sustainable over a long-term planning horizon despite the evidence put forward in my Supplemental and Amending Direct Testimony to the contrary, and developing an arbitrary MISO Planning Resource Auction ("PRA") clearing price forecast that assumes prices will essentially remain flat in real terms over the 20-year planning horizon, concluding that a transmission-only scenario is the lowest-cost alternative as compared to NOPS when those changes are made. Similar to the Joint Intervenors, Mr. Rogers's alternative assumptions do not appear reasonable or based on any credible evidence that has been offered in this proceeding.

The two essential underpinnings of the Advisors' sensitivities – utilizing a MISO PRA capacity price forecast that is essentially held constant in real terms at $6/kW-year (~6% of the cost of new entry or "CONE") over a 20-year planning horizon, and decrementing the Company's load forecast for the Council's 2% DSM goal for 20 years – are both unreasonable in the context of long-term resource planning. Therefore, the Advisors' revised economic results and corresponding revised bill impacts are not reasonable. The Council's evaluation of the Company's application to construct NOPS should be based on the Company's Reference Portfolios and consideration of ENO's unique planning circumstances.

III. UNIQUE PLANNING CIRCUMSTANCES

Q7. WHAT ARE ENO'S UNIQUE PLANNING CIRCUMSTANCES?

A. As discussed in my Direct Testimony and Supplemental and Amending Direct Testimony, with the deactivation of ~781 MW of capacity from the two Michoud units in June 2016, the Company is now 100% dependent on transmission to serve its load, which load resides completely in the transmission-constrained DSG load pocket. Prior to deactivation, Michoud Units 2 and 3 represented approximately 28% of the capacity in DSG,[5] and they both supported reliability in New Orleans and provided an important resource to mitigate market- and supply-related risks. The following Figure 1 shows the DSG and Amite South load pockets, as well as the approximate location of the Ninemile Point generating facility, which is the only significant source of generating capacity remaining in the DSG load pocket.[6]

Figure 1

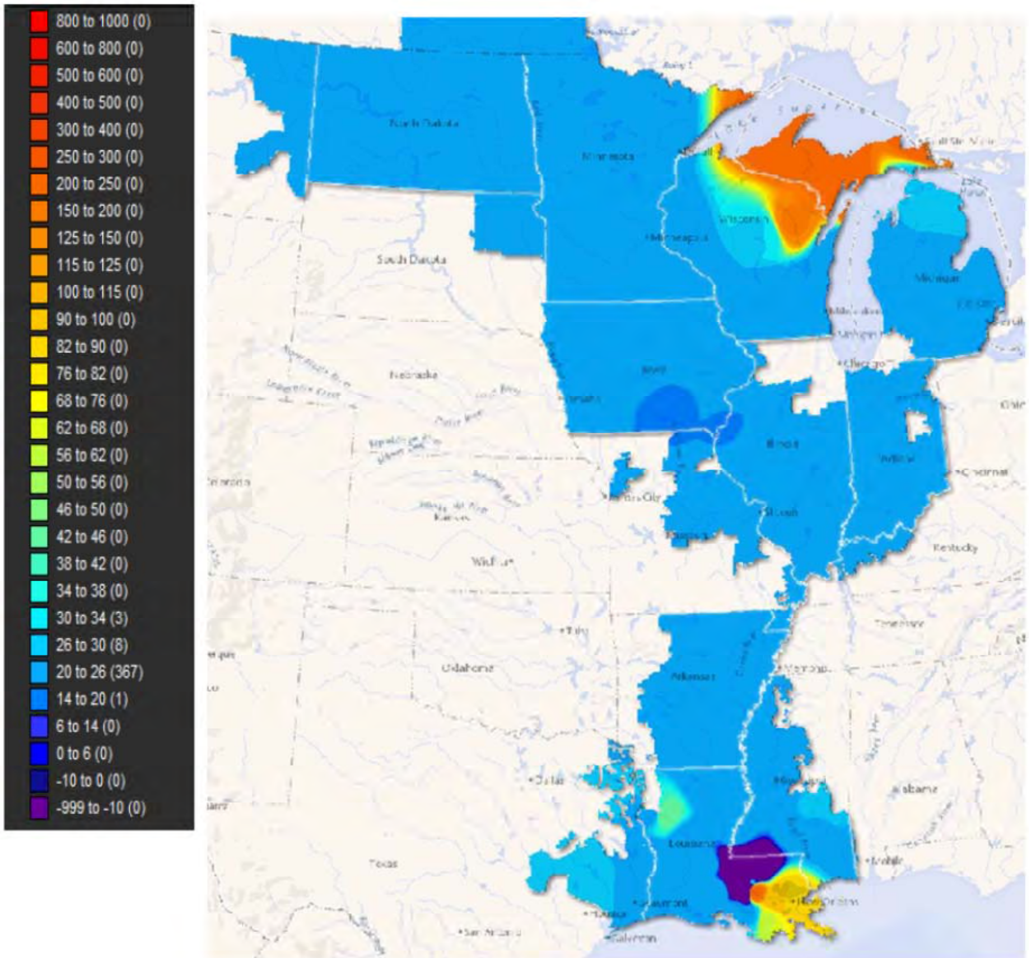
The Company's service area is at the eastern geographic boundary of the DSG load pocket, which is surrounded by water on three sides, and thus relies heavily on

5 At the time Michoud Units 2 and 3 deactivated, Ninemile units provided 71% of the capacity, Michoud provided 28%, and Buras was less than 1%.

6 The Buras unit located at the end of DSG provides approximately 12 MW.

high-voltage transmission lines to import power from West to East. The DSG load pocket is transmission-constrained, which requires the commitment of Ninemile Point to support reliability in New Orleans. Entergy Louisiana, LLC owns the Ninemile Point facility, and two of the three generating units in operation, or approximately 71% of the Ninemile Point generating capacity, were placed into service in the early 1970s and will not operate in perpetuity. Figure 2 below illustrates the effect of transmission constraints in MISO on real-time LMPs. Because DSG and the broader Amite South load pockets are transmission constrained, when one or more of those constraints bind, LMPs in the New Orleans Load Zone tend to increase as shown in Figure 2.

Figure 2[7]



The majority of ENO's generating capacity is located outside of both DSG and the broader Amite South load pocket, both of which also rely, in part, on aging legacy gas generating capacity that was placed in service over 40 years ago. ENO has Purchase Power Agreement ("PPA") rights to approximately 60 MW of the capacity in Amite South and DSG, which could potentially deactivate early. As is apparent from Exhibit SEC-11, early deactivation of some or all of the Company's contracted

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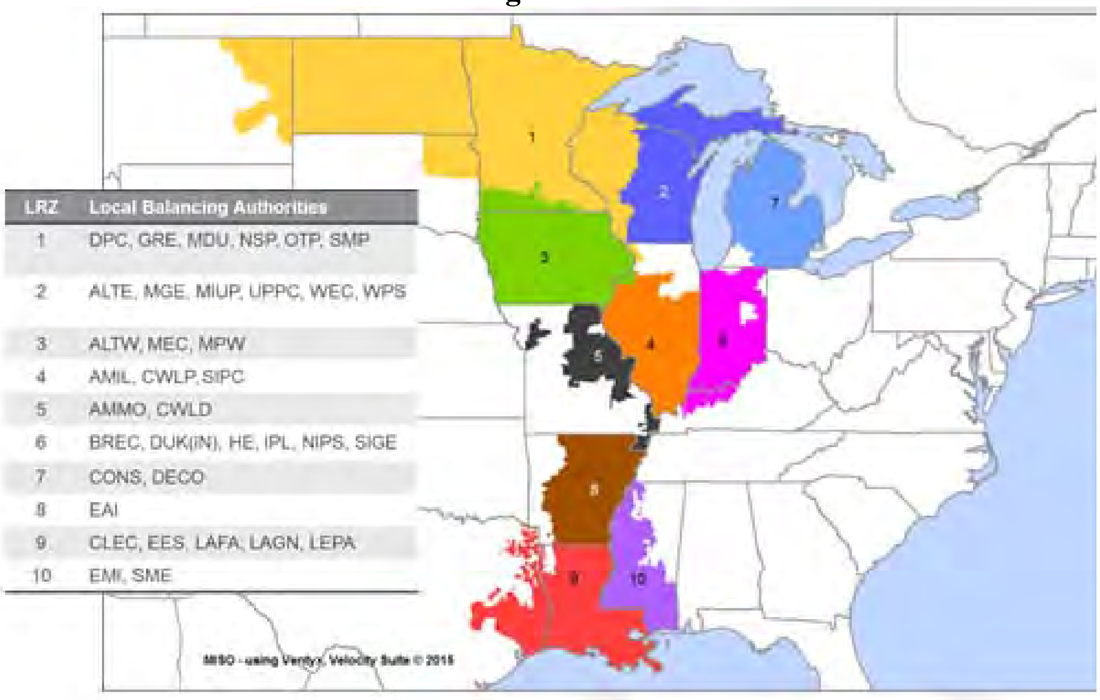
[7] Slide 5 from MISO's presentation at the September 13, 2017 New Orleans City Council Utility, Cable, Telecommunications and Technology Committee.

legacy generation could have a significant effect on ENO's capacity position. Also, if load were to increase at a rate higher than forecasted, the Company's capacity need would be further exacerbated.

In addition to the load pocket considerations, [redacted]% of the Company's generating capacity is located outside the New Orleans Load Zone, which increases customer's exposure to LMPs during planned and unplanned outages of transmission and generation. This risk is compounded by the fact that [redacted]% of the Company's generation is located outside Local Resource Zone ("LRZ") 9, namely LRZs 8 and 10, whereas 100% of the Company's load is located in LRZ 9. As I explain in my Supplemental and Amending Direct Testimony, generating capacity that is located in a different LRZ from load involves exposure to the potential for separation of PRA clearing prices.[8] In that situation, ENO's capacity resources outside of LRZ 9 could be paid less than ENO's load is charged. Deploying new resources such as NOPS within LRZ 9 would partially mitigate that risk. The following Figure 3 shows the LRZs in MISO.

[8] Cureington Supplemental and Amending Direct at 22-23.

Figure 3



IV. MISO CAPACITY PRICE PROJECTIONS

Q8. ONE OF THE FUNDAMENTAL ARGUMENTS OF THE JOINT INTERVENORS AND THE ADVISORS IS THAT MISO, INCLUDING ZONE 9 WHERE ENO IS LOCATED, HAS SURPLUS CAPACITY AND, THUS, LOW CAPACITY PRICES IN THE ANNUAL MISO PRA. THEY ASSERT THAT THOSE CONDITIONS WILL CONTINUE INTO THE FUTURE AND THAT EQUILIBRIUM IS NOT A CONCERN. IS THAT A REASONABLE ASSUMPTION?

A. No. The Joint Intervenors draw unwarranted conclusions from the most recent Organization of MISO States ("OMS") MISO survey ("Survey"), and they focus on speculative new generation projects that may or may not happen while ignoring that the potential capacity surplus they cite contains existing units that could deactivate early. The Joint Intervenors and the Advisors also place entirely too much emphasis on historical and volatile PRA auction clearing prices, which, as explained by the MISO Independent Market Monitor ("IMM"), do not reflect the true price of capacity and are affected by a flawed capacity market.[9]

To begin, it is important to understand that the OMS MISO Survey focuses on the near-term five-year period through 2022. Through long-term planning, ENO is trying to ensure that it has sufficient capacity to meet its customer load obligations for the next 20 years. Yet the Joint Intervenors tend to focus on what they refer to as "dramatic" changes in projections for 2018 as between the 2016 Survey and the most recent 2017 Survey. While I agree that the latest Survey, as did the one before, indicates there may be sufficient capacity in MISO for the next few years, it still supports the Company's position that **the current surplus is projected to decline dramatically during that 5-year period**. As discussed below, the surplus then converts to a deficit in year 6, or 2023.

Q9. PLEASE EXPLAIN.

A. The primary driver of the Company's capacity price forecast is the projected decline in the current capacity surplus in MISO, which will lead to higher capacity prices as capacity supply and demand converge (*i.e.*, equilibrium). The latest Survey shows a moderation in the rate of that decline compared to the prior year, but it still indicates a decline toward equilibrium. For example, based on committed capacity projections, the latest survey shows a MISO-wide surplus of 3.9 GW in 2019, which declines to

[9] Exhibit SEC-15, 2016 State of the Market Report for the MISO Electricity Markets (June 2017).

0.7 GW in 2022.[10] For Zone 9 in particular, where ENO's load is located, the projected committed capacity surplus in 2022 is just 0.2 GW (200 MW), which represents just 0.9% of the projected total committed capacity of 23,300 MW for 2022.[11] A surplus that small means the Zone is one early deactivation of an aging generating unit away from a deficit. There are over 3,200 MW of aging resources in Amite South alone, which is a relatively small geographic area compared to Zone 9,[12] and some of those resources could deactivate early. In summary, the latest OMS MISO Survey again confirms the Company's position that the capacity surplus in MISO is projected to decline. On the other hand, the Joint Intervenors witnesses' extreme optimism with respect to "potential capacity" pushing off equilibrium is not a reasonable long-term planning assumption considering risk.

Q10. WHY IS IT UNREASONABLE FOR THE JOINT INTERVENORS TO PLACE SO MUCH EMPHASIS ON POTENTIAL CAPACITY PROJECTIONS IN THE OMS MISO SURVEY?

A. First, it is important to understand that there are two components to the "Potential Capacity Projections" that the Joint Intervenors are relying on in the 2017 Survey.[13] The first is "Potential New Capacity," which is 35% of the proposed resources that "are in the Definitive Planning Phase (DPP) of the MISO Generator Interconnection

[10] Exhibit SEC-16, 2017 OMS MISO Survey Results at 9.

[11] Exhibit SEC-16 at 15, 71.

[12] *See* Figures 1-2, *supra*.

[13] *See, e.g.,* Exhibit SEC-16, slide 15, illustrating that "Potential Capacity" is 1,300 MW of the potential 1,500 MW surplus in Zone 9 in 2022 (*i.e.*, slide 15 shows a potential surplus comprised of 200 MW of committed capacity and 1,300 MW of potential capacity).

queue."[14] The second, which they ignore, is "Potentially Unavailable Resources," which includes "potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint."[15] With respect to the Potential New Capacity, despite how it may sound, being in the DPP queue does not necessarily mean that there is a high probability of those resources being constructed and/or interconnected to MISO.

Q11. PLEASE EXPLAIN.

A. The MISO Generator Interconnection Queue includes generation projects under development by both utilities with an obligation to serve load as well as merchant power development companies. Registering a project in the queue is just an initial, almost exploratory, step in the process, with much left to be accomplished before those projects are ever constructed. Further, the decision to include 35% of the projects in the DPP queue as the amount of "Potential New Capacity" in the "Potential Capacity Projection" appears largely arbitrary and resulted from discussions with stakeholders and high-level assumptions about the ultimate success rate of past projects that went through the DPP.[16] Importantly, most of the projects will require regulatory approval before being built, which is never certain.

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[14] Exhibit SEC-16 at 8-9.

[15] Exhibit SEC-16 at 8-9.

[16] The analysis considered the fact that 37% of projects withdraw from the queue and 26% of projects complete Generator Interconnection Agreements ("GIAs"). Thus, MISO concluded the possible pool of successful projects is therefore between 26% and 63%, and thus MISO proposed and stakeholders agreed to add 35% to the "Potential Capacity Projections."

Q12. DO YOU HAVE COMMENTS ABOUT THE OTHER COMPONENT OF THE POTENTIAL CAPACITY PROJECTION IN THE SURVEY?

A. Yes. The other component of the "Potential Capacity Projection" is "potential retirements or suspensions."[17] In other words, included in the 1,300 MW of "potential capacity" shown in the survey for Zone 9 in 2022 are existing units that may retire or suspend operations. Thus, the 1,300 MW of potential capacity is not, as the Joint Intervenors imply, made up entirely of new projects that might add capacity in the Zone. It includes some existing capacity that may disappear.

Disregarding the 1,300 MW of potential new resources that may never be built and existing resources that may retire leaves only a projected surplus of 200 MW of "Committed Capacity" in Zone 9 in 2022.[18] That represents a very slim margin for error, especially considering that the Intervenors have made no effort to determine the likelihood of any of the potential new resources being built or the likelihood of any of the potentially retiring units continuing operations. Saying that ENO can reasonably rely on there being around 200 to 1,500 MW of excess capacity in Zone 9 in 2022, and thus avoiding equilibrium and spiking capacity prices, is a very risky assumption.

[17] Exhibit SEC-16 at 8. The Survey sites as an example, a resource that has submitted an attachment Y2. Exhibit SEC-16 at 17.

[18] Exhibit SEC-16 at 15.

Q13. IS EVEN THE 200 MW OF SURPLUS "COMMITTED CAPACITY" PROJECTED FOR 2022 CERTAIN?

A. No. According to the OMS MISO survey, "Committed Capacity" includes new generators with signed interconnection agreements. Having a signed interconnection agreement does not mean a unit has been built or guarantee that it will be built. That capacity also includes the legacy gas units in Amite South which, as I have stated earlier, have reasonable chances of deactivating sooner than assumed, if it is economic for the owner of that capacity to do so. Accordingly, there is no assurance that there will even be 200 MW of surplus capacity in Zone 9 in 2022.

Q14. ARE THERE OTHER INDICATIONS THAT THE CAPACITY SURPLUS IN MISO IS DECLINING TO A POINT OF EQUILIBRIUM IN 2023?

A. Yes. The 2017 MTEP Resource Adequacy Report cited by Mr. Fagan examines resource adequacy in MISO through 2028. It states that "[b]eginning in 2023 MISO capacity is projected to fall below the PRMR [planning reserve margin requirement] and remain there for the rest of the assessment period."[19] In other words, "MISO projects that reserve margins will continue to tighten over the next five years, approaching the reserve margin requirement."[20] According to the report at Table 6.2-1, and which is reproduced as Table 1 in Mr. Fagan's Direct Testimony, there is projected to be a deficit of 1,400 MW in 2023, which deficit grows to 2,500 MW in

[19] Exhibit SEC-17 at 14. While marked "draft," this is the latest version (December 2017), which is expected to be approved by the MISO Board of Directors on December 7, 2017.

[20] Exhibit SEC-17 at 15.

2028.[21] These projections, from MISO nonetheless, underscore the Company's position that the capacity surplus is projected to decline and prices will rise as equilibrium approaches over the next five to ten years.

Mr. Fagan, on the other hand, claims there may be as much as 20,000 MW of undefined potential capacity in MISO in 2022.[22] Mr. Fagan's position that MISO's resource adequacy projections might be overstated because of undefined "potential" capacity additions is not a reasonable or objective way to evaluate the MISO capacity market. Moreover, Mr. Fagan did not provide any analysis of what projects might be in that undefined queue. If Mr. Fagan's optimism does not pan out, ENO would find itself without sufficient capacity to serve its load at a time when capacity prices are rising and building any new capacity would entail a multi-year lead time. Accordingly, following MISO's methodology and projections with respect to projected resource adequacy is the more reasonable approach for long-term resource planning by a utility with an obligation to reliably serve its customers.

Q15. DOES NERC ADDRESS RESOURCE ADEQUACY IN MISO?

A. Yes. NERC annually produces a long-term reliability assessment ("LTRA"), which includes MISO. According to the most recent LTRA, "MISO is currently projected to fall below their target of 15.20 percent to an Anticipated Reserve Margin of 13.89

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[21] Exhibit SEC-17 at 14, Table 6.2-1.

[22] Fagan Direct at 18, citing to slide 13 of the 2017 OMS MISO Survey, which depicts MISO-wide potential capacity "not included in regional or zonal totals."

percent in 2022 and continue to decrease to 9.07 percent by the year 2026."[23] According to the report, MISO will need "approximately 8 GW of additional resources by the end of the 10-year forecast in order to maintain the Reference Margin requirements of 15.2 percent."[24] NERC also designated MISO as one of only four assessment areas with a short-term "medium reliability concern."[25] And it is one of only three assessment areas projected to be short of the designated Reference Margin level in year 10. Figure 4 below shows MISO's 2026 planning reserve margin along with the other 21 assessment areas.[26]

Figure 4

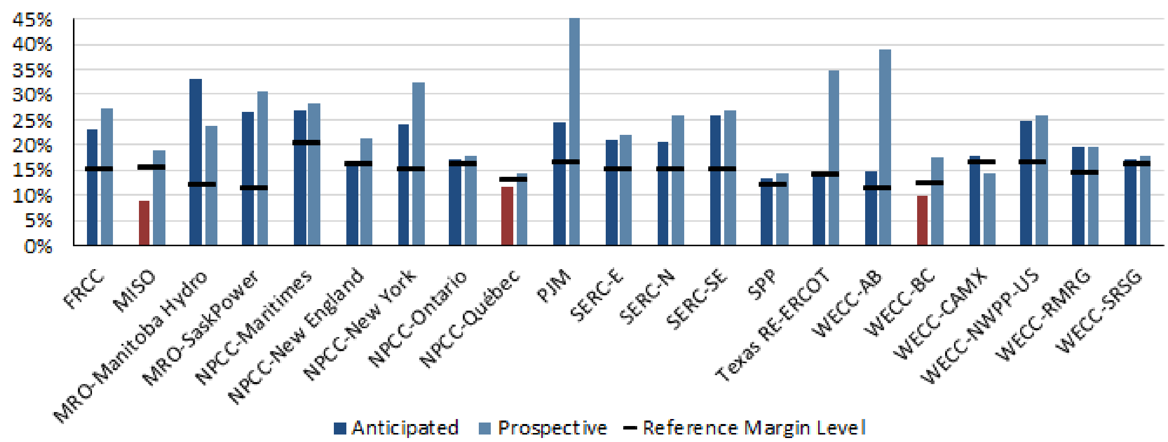


Figure 1.3: Planning Reserve Margins for Year 10 (2026)

The NERC LTRA explains that the "shortfall in projections is due to generation retirements outpacing the addition of Tier 1 resources."[27] Further, similar to the OMS MISO Survey, while there are prospective projects that could add

[23] Exhibit SEC-18 at 3.

[24] Exhibit SEC-18 at 6.

[25] Exhibit SEC-18 at 4. MISO is also one of six assessment areas with a medium reliability concern in the long term as well.

[26] Exhibit SEC-18 at 3, Figure 1.3: Planning Reserve Margins for Year 10 (2026).

[27] Exhibit SEC-18 at 6.

capacity, there are prospective retirements that would have an offsetting effect. As shown below in Figure 5, unconfirmed retirements could lead to a significant capacity deficit.

Figure 5

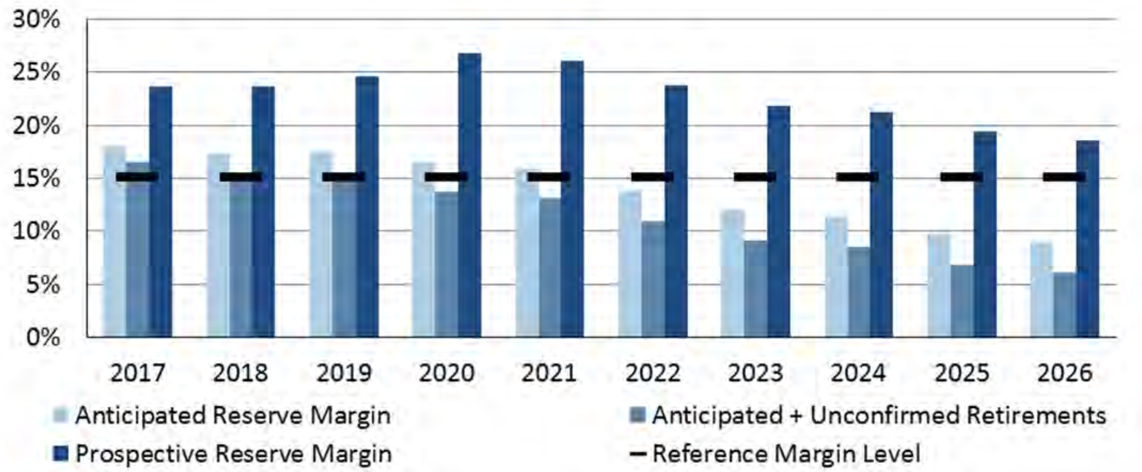


Figure 1.8: MISO Reserve Margins with Unconfirmed Retirements

Q16. DO YOU HAVE ANY ADDITIONAL SUPPORT FOR THE COMPANY'S VIEWPOINT ON MISO'S DECLINING CAPACITY POSITION?

A. Yes. IHS Markit, a globally recognized firm that provides insight and analysis of major industries and markets, produces an annual capacity value forecast for MISO, which indicates sharply increasing capacity prices in MISO South beginning in 2022.[28] Further, the MISO IMM recently concluded that "planning reserve margins have been decreasing and will likely continue to fall as resources retire and suppliers continue to export capacity to PJM."[29]

[28] HSPM Exhibit SEC-19.

[29] Exhibit SEC-15 at 12.

Q17. ARE THE HISTORICAL PRA CLEARING PRICES INDICATIVE OF FUTURE CAPACITY PRICES?

A. No. First, I want to stress that it is not reasonable to rely on short-term annual purchases of capacity credits through the PRA to address long-term resource needs. In fact, Advisors witness Rogers agrees.[30] ENO is in need of a long-term source of local peaking capacity with a known cost, which would hedge against annual capacity auction prices that can be volatile and may escalate sharply from today's level.

Second, it is illogical to assume that one year's clearing price is any indication of the next year's price. The PRA is an annual market; therefore, the Auction Clearing Price ("ACP") in a given planning year reflects the balance of supply offers (capacity) and demand requirements (peak load) in that year. That view changes annually and sometimes dramatically. For example, for the 2015/2016 planning year the ACP for Zones 2-3 and 5-7 was \$3.48/MW-day, which ACP increased to \$72/MW-day for the 2016-2017 planning year. Similarly, the market observed Zone 4 spike to \$150 in 2015-2016, which was nearly ten times the 2014-2015 price of \$16.75.

Third, it is not surprising that, in general, historical PRA clearing prices in MISO South have been low. It is undisputed that there is *currently* a capacity surplus in MISO. Thus, the auction clearing price for capacity in MISO's PRA does not reflect the true cost of capacity. But as I discussed above, that situation is not expected to exist in perpetuity; rather, as indicated by MISO and NERC, the capacity

[30] Rogers Direct at 32.

surplus in MISO is expected to decline over the next five to ten years. When a capacity deficit exists, it is reasonable to expect capacity prices in the MISO PRA to approach, if not equal, new build prices.

Q18. IS THERE EVIDENCE THAT THE PRA CLEARING PRICES ARE NOT REPRESENTATIVE OF THE TRUE VALUE OF CAPACITY?

A. Yes. According to the MISO IMM, "[t]he demand for capacity in the PRA continues to poorly reflect its true reliability value, which undermines its ability to provide efficient signals for investment and retirement decisions."[31] The report specifies that the $1.50 per MW-day 2017/2018 auction clearing price "fails to reflect the true value of capacity in MISO. In addition, the year-over-year volatility in MISO's auction clearing prices creates uncertainty, leading to highly unpredictable expected future revenue streams for long-term investment decisions."[32] Accordingly, as the utility tasked with long-term resource planning and an obligation to reliably serve its customers, ENO cannot base its long-term planning decisions on prevailing ACPs in MISO's PRA in any given year.

[31] Exhibit SEC-15 at 15.

[32] *Id.*

Q19. DID THE MISO IMM REPORT COMMENT SPECIFICALLY ON DIFFICULTIES IN THE CAPACITY MARKET ASSOCIATED WITH UTILITIES OPERATING IN A LOAD POCKET?

A. Yes. In the discussion of its concerns with MISO's current capacity market, the IMM report states:

> The third issue with MISO's current capacity market relates to definitions of local resource zones. Currently, a local resource zone cannot be smaller than an entire LBA. However, capacity is sometimes needed in certain load pockets within LBAs. A good example of this type of requirement is the Narrow Constrained Areas (NCAs) in MISO South where ***the addition of fast-start capacity would be extremely valuable***. Hence, we recommend that MISO's local resource zones be established based primarily on transmission deliverability and local reliability requirements.[33]

As demonstrated throughout the Company's application, it is striving to build a fast-start resource to meet the Company's long-term needs and support grid reliability in New Orleans.

[33] SEC-15 at 18 (emphasis added). Amite South, including DSG and the ENO service area, is one of the NCAs in MISO South where the addition of quick-start resources would be "extremely valuable."

Q20. ADVISORS WITNESS ROGERS CLAIMS THAT THE THEORY OF SUPPLY AND DEMAND MAY NOT APPLY IN MISO BECAUSE MOST OF THE LOAD-SERVING ENTITIES ARE VERTICALLY-INTEGRATED UTILITIES WITH AN OBLIGATION TO SERVE AND, THEREFORE, WILL BUILD CAPACITY WITHOUT AN ECONOMIC INCENTIVE. DO YOU AGREE?

A. No, to the extent Mr. Rogers relies on this claim to support his argument that capacity prices will remain flat in real terms over the 20-year planning horizon. First, this approach assumes that the necessary capacity additions are timed such that supply will always exceed demand in order for ACPs to remain flat over the planning horizon, which is an unreasonable assumption for purposes of long-term planning. The timing of deactivations and new resource additions rarely coincide perfectly as planned, as evidenced by the early deactivation of Michoud Units 2 and 3.

Second, Mr. Rogers's claim also rests on a static view of demand. While load growth in MISO moderated in the 2017 OMS MISO Survey, for the same reasons I describe for the Company's load forecast, there exists the possibility that other Load Serving Entities ("LSEs") could experience increases in demand, leading to an increase in the need for capacity in the PRA. Thus, while LSEs such as ENO certainly take seriously their obligation to serve whatever load materializes, relying on speculation that the market will remain over-supplied for the entire 20-year planning horizon is not reasonable for purposes of long-term planning.

Third, this assumes that other utilities and their regulators will act responsibly with respect to resource planning and not, as the Joint Intervenors have suggested, "exploit" the market until capacity prices rise. When prices rise, it will take several years to obtain regulatory approval and construct new units, during which time customers will be exposed to high capacity prices that could have been avoided but for ill-fated attempts to time the market. This also begs the question of how many other utilities and regulators will make a similar assumption, *i.e.*, there is no need to build because others will do it. Here, the Council should recognize the value of having a local resource owned or controlled by the utility it regulates to protect New Orleans against rising capacity prices and reliability risks, instead of increasing reliance on entities over which the Council has no regulatory authority.

Q21. HOW DO YOU RESPOND TO JOINT INTERVENORS WITNESSES STANTON'S AND FAGAN'S CLAIMS THAT MISO TENDS TO OVERSTATE ITS PROJECTED RESOURCE NEEDS?[34]

A. First, they are focusing on a relatively short time period. Second, load forecasts are not static; rather, they are meant to change and respond to evolving market dynamics. Criticizing a load forecast for being wrong is like criticizing a single hurricane model for being wrong in predicting the exact path of a storm; as atmospheric conditions change, the model must be adjusted with new data to update its forecast. Such tools are not capable of casting a perfect prediction in stone, but that is not the intent of forecasting models.

Mr. Fagan also suggests that recent declines in net load growth establish a pattern that will continue into the future, but I disagree.[35] This is pure speculation on

[34] Stanton Direct at 40-41; Fagan at 23-25.

his part without any evidence to support it. Load forecasts will change, but claiming that just because a forecast declined over some historical period of time it will continue to do so in perpetuity is speculative. The point is that no one knows for sure, but a prudent utility planner will utilize the best information available and not rely on pure speculation. I also note that neither Dr. Stanton nor Mr. Fagan performed any specific analysis with respect to MISO's forecast or submitted their own forecast that they think would be more reasonable. In other words, as in all of their testimony, they criticize the Company's analysis but provide no alternative analysis for consideration.

Q22. ALTHOUGH MR. FAGAN FOCUSES PRIMARILY ON SHORT-TERM CAPACITY POSITIONS IN MISO, DOES HE HAVE AN OPINION ON CAPACITY AVAILABILITY OVER THE LONG-TERM?

A. Like most of Mr. Fagan's analysis, it is based on optimistic speculation around the availability and cost of solar and wind resources, optimistic speculation about the effectiveness and cost of energy efficiency, and optimistic speculation about the pace of retirement of aging fossil units and their replacement by new technologies.[36] Importantly, and in addition to the extremely optimistic and speculative nature of his beliefs, his view of available capacity over the long-term is dependent on constructing transmission to deliver remote wind resources in MISO North.[37] Mr. Charles Long

[35] Stanton Direct at 21.

[36] Fagan Direct at 27.

[37] Fagan Direct at 27-29.

addresses points related to transmission, but as indicated in my Direct and Supplemental and Amending Direct Testimonies, the Company is already over-reliant on transmission to serve load. Increasing that reliance by adding even more remote resources in combination with more transmission does not provide the local reliability or market and supply risk mitigation that an in-region resource would provide. NOPS, on the other hand, is designed to meet the Company's long-term needs consistent with its unique planning circumstances, and is not dependent on Mr. Fagan's optimistic speculation in order to meet those needs.

V. ENO'S PROJECTED CAPACITY NEED

Q23. THE OTHER FUNDAMENTAL ARGUMENT PRESENTED BY THE JOINT INTERVENORS IS THAT ENO'S LOAD FORECAST AND NET CAPACITY POSITION MAY BE OVERSTATED BECAUSE THEY DO NOT REFLECT THE JOINT INTERVENORS' ASSUMPTIONS REGARDING DSM, RENEWABLE RESOURCES, AND DISTRIBUTED GENERATION THAT THEY CONTEND ARE REASONABLE. ADVISORS WITNESS ROGERS SIMILARLY CONTENDS THAT ENO'S LOAD FORECAST IS OVERSTATED FOR NOT INCLUDING THE COUNCIL'S 2% DSM GOAL. DO YOU AGREE WITH THEIR ASSUMPTIONS?

A. No. Their assumptions are not reasonable, and I address each one below.

Q24. JOINT INTERVENORS WITNESS STANTON AND ADVISORS WITNESS ROGERS CRITICIZE THE COMPANY'S REFERENCE LOAD FORECAST FOR

NOT INCLUDING THE COUNCIL'S 2% DSM GOAL.[38] IS THAT A REASONABLE ASSUMPTION FOR USE IN ESTIMATING LONG-TERM DSM POTENTIAL IN NEW ORLEANS?

A. No, and neither Dr. Stanton nor Mr. Rogers offers any reasonable basis upon which to assume that 2% annual incremental energy efficiency savings can be achieved in New Orleans at all, let alone in a cost-effective manner. They also ignore that the Council's goal is aspirational and not meant to supplant a reasoned and analytical approach to estimating long-term DSM potential.

Q25. PLEASE EXPLAIN.

A. The Council has set an aspirational goal that targets an increase in savings of 0.2% per year until such time as the programs generate 2% savings per year. However, the Company is not under a mandate to achieve the goal; instead, it is simply required to comply with the Council's request to target the annual increase in savings. Importantly, the Council requires that cost-effectiveness testing be used to develop Energy Smart program savings targets and implementation budgets.[39] This requirement acts to protect customers from paying for efficiency programs where costs exceed expected benefits. The Company is currently in its seventh year of energy efficiency program implementation, and at the end of Program Year 6 it had

[38] Stanton Direct at 13-14; Rogers Direct at 10-13.

[39] Resolution R-09-267 at 3 ("Whereas, all programs approved by the Council, with the exception of low income weatherization and domestic solar water heater programs, must be determined to be cost-effective under the industry accepted testing criteria of the Total Resource Cost ("TRC") Test and the Program Administrator Cost ("PAC") Test as defined in the California Standard Practice Manual, "Economic Analysis of Demand-Side Programs and Projects," October 2001.").

achieved approximately 0.34% annual savings, consistent with prior years despite increased program budgets.

Moreover, as Navigant concluded in its report (Exhibit SEC-14), the assumptions required to force their proprietary Demand Side Management Simulator (DSMSim™) model to solve for 2% annual savings in New Orleans were theoretical and required Navigant to relax industry standard thresholds for cost-effectiveness, incentive levels, administrative costs, and market saturation and assume measures not in existence today will be invented and available at some unknown future date. Under those theoretical assumptions, Navigant estimated that achieving the Council's 2% aspirational goal is estimated to cost **$2.3 billion** over the planning horizon, which costs would ultimately be borne by ENO's customers. This approach to long-term resource planning is not reasonable, and I note that it is inconsistent with Dr. Stanton's own prior assertion that the "more modern approach" is to emphasize the acquisition of *cost-effective* supply- and demand-side resources.[40]

Q26. JOINT INTERVENORS WITNESSES STANTON AND FAGAN ALSO CRITICIZE ENO'S FORECAST FOR NOT UTILIZING AT LEAST THE 0.85% HIGH CASE POTENTIAL ENERGY EFFICIENCY SAVINGS DISCUSSED IN NAVIGANT'S REPORT.[41] HOW DO YOU RESPOND?

A. That would be inappropriate because Navigant's 0.85% savings level is not a reference case savings level. To begin, the Company engaged Navigant to assess the

[40] Stanton Direct at 10.

[41] Stanton Direct at 31-32; Fagan Direct at 12, 16, 32.

feasibility and cost of achieving the Council's aspirational 2% kWh savings goal. As explained in Navigant's report, the analysis included three scenarios for evaluation, starting with a High Case Achievable scenario to establish the ceiling for cost-effective long-run energy efficiency potential in New Orleans, against which the remaining two scenarios could be compared. The second scenario, referred to as High Case Theoretical – Known Measures, relaxed the already aggressive assumptions made in the High Case Achievable scenario in order to determine the cost necessary to reach 2% and assess the effect of saturation on achievable savings potential thereafter. Because the results of the second scenario showed that the effect of saturation would significantly reduce long-run achievable potential, the third and final case, referred to as High Case Theoretical – Known and Unknown Measures, adopted the unrealistic assumptions of the second scenario and incorporated the additional theoretical assumption that sufficient future efficiency measures not available today will become available to sustain a 2% annual savings rate over the planning horizon. Navigant then presents the results of each case and also contrasts those results with a benchmarking analysis of actual savings rates for southern states.

Q27. WHAT WERE THE ACTUAL SAVINGS RATES FOR SOUTHERN STATES IN 2015?

A. According to Navigant's report, it was 0.61% or less.[42]

[42] Exhibit SEC-14, Figure 10, p. 33.

Q28. NAVIGANT'S BENCHMARKING ANALYSIS FOCUSED ON THE SOUTHERN UNITED STATES. ARE THERE CIRCUMSTANCES THAT CAN AFFECT THE LEVEL OF DSM SAVINGS ACHIEVED AMONG UTILITIES, REGIONS, AND STATES?

A. Yes. DSM savings can be affected by:

- different utility avoided costs;
- different retail rates;
- different maturity in energy efficiency work force; and
- different customer mix – most states and utility territories have a large, diverse customer mix. ENO's mix of customers provides less of the diversity that helps utilities and states achieve higher savings at lower cost.

Q29. BEFORE ADDRESSING COMPARISONS MORE BROADLY, HOW DOES THE CITY OF NEW ORLEANS COMPARE TO A SOUTHERN STATE?

A. New Orleans is a much smaller geographic area when compared to a southern state. When considering an entire state, the diversity of the customer base can provide significant opportunities to target large projects capable of increasing the savings rate in a given year. In contrast, New Orleans has a very homogenous customer base with over 75% of load served in the residential and commercial market segments. In addition, despite having retail electric rates 15-20% below the national average, because of the high number of cooling degree days in the Southeast, customers in New Orleans have higher usage when compared to other parts of the U.S. with fewer cooling degree days. As a result, the same efficiency measure installed in a region of the U.S. with relatively low usage can have a higher impact on the savings rate for that customer when compared to regions with relatively higher usage.

Q30. HOW DOES ENO COMPARE TO THE STATES ACHIEVING 1% OR HIGHER DSM SAVINGS, WHICH THE JOINT INTERVENORS IMPLY IS A FAIR COMPARISON?

A. I have not conducted that analysis, and neither has Dr. Stanton or Mr. Fagan. I understand that the top 16 performing states referenced by Dr. Stanton are: Massachusetts, Rhode Island, Vermont, Washington, California, Connecticut, Arizona, Maine, Hawaii, Minnesota, Illinois, Michigan, Oregon, Idaho, New York, and Iowa.[43] I would expect there to be differences between those states and New Orleans with respect to avoided costs, retail rates, market maturity, geography, climate, and customer mix.

In fact, Navigant presented benchmarking results for states in the southern United States, which indicates average **potential** savings of 0.86%.[44] **Actual** savings in the southern states, according to the ACEEE report cited by Dr. Stanton, tend to be much less: Oklahoma (0.39%), Missouri (0.39%), Georgia (0.27%), Mississippi (0.26%), Tennessee (0.19%), Texas (0.19%), Florida (0.11%), Louisiana (0.10%), Alabama (0.6%).[45] Accordingly, the Joint Intervenors' argument that ENO should be

[43] Refer to Dr. Stanton's footnote 48 on page 32 of her testimony. I believe that the page number referenced in her citation is incorrect and that the table listing the 2016 incremental net savings percentages by state is Table 9 on page 29 of the ACEEE report. I have attached that table as Exhibit SEC-20.

[44] Exhibit SEC-14 at 32.

[45] Exhibit SEC-20.

able to achieve cost-effective DSM savings in excess of 1% just because some states that are nowhere near Louisiana have done so at least once is meaningless without an analysis of whether the circumstances that can affect DSM savings are similar, and which analysis they have not done. It is also at odds with the actual savings of states that are in proximity to Louisiana, and Louisiana itself.

Q31. WOULD IT BE REASONABLE TO USE THE NAVIGANT 0.85% HIGH CASE ACHIEVABLE RESULT AS A BASE OR REFERENCE CASE IN LONG-TERM PLANNING ANALYSES?

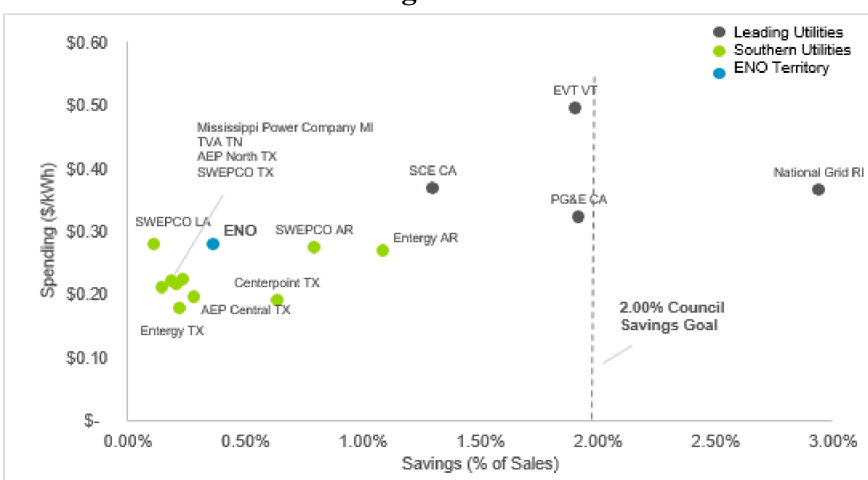
A. No. As the description implies, the High Case Achievable Scenario represents "Navigant's best-case judgment regarding a level of EE that would be achievable with an aggressive roll-out of EE programs."[46] In fact, Navigant's three scenarios (high case achievable, theoretical achievable with known measures, and theoretical achievable with known and unknown measures) were intended to assess the feasibility of the Council's 2% goal by starting with the maximum long-run achievable potential that may be possible under aggressive assumptions. Consistent with the Company's Reference Portfolios, reference scenarios are typically calibrated to historical program penetration and existing program spend levels. Thus, when considered in that context, Navigant's High Case Achievable is not a floor for incorporation into prudent long-term resource planning, but rather a ceiling more appropriate for consideration as an aspirational goal.

[46] Exhibit SEC-14 at 19.

Q32. IS IT SURPRISING THAT NAVIGANT ESTIMATED IT WILL COST MORE THAN TWICE THE CURRENT ENERGY SMART SPENDING LEVELS TO ACHIEVE 0.85% IN AVERAGE ANNUAL SAVINGS IN THE HIGH CASE ACHIEVABLE SCENARIO?

A. No. Dr. Stanton states that "ENO's program costs do not increase commensurately with projected savings," and the implication seems to be that savings should rise proportionally with costs.[47] Aside from comparing savings and cost levels from other states, which I addressed above, Dr. Stanton provides no support for such a theory. To the contrary, Figure 6 below demonstrates that there is no trend line between $/kWh and the savings percentage, and doubling program spending does not necessarily equal doubling savings.

Figure 6[48]



47 Stanton Direct at 33.

48 Exhibit SEC-14 at Figure 11, p. 34.

In addition, it is my understanding that, as DSM programs mature and move to more advanced stages, many energy efficiency measures become more expensive. In other words, the efficiency options tend to get costlier to access and it requires more money to be spent to encourage customers to participate in new or existing programs. This concept has been described as moving up the energy efficiency tree. As a portfolio captures the lower cost measures, the remaining potential is higher up the tree and costlier. This is also exhibited with an efficiency supply curve, which is a commonly-used method in the industry to rank order estimated savings from energy efficiency measures based on their costs. There are the energy measures lower on the supply curve at lower costs, and as you move up the slope of the supply curve, energy efficiency measures yield savings at higher costs. Thus, it is not surprising that Navigant calculated it would cost more than twice current spending levels to achieve roughly double the savings.

Q33. HOW DO YOU RESPOND TO DR. STANTON'S CLAIMS THAT THE COSTS OF THE MEASURES INCLUDED IN NAVIGANT'S MODELS (EXHIBIT SEC-14) ARE UNREALISTICALLY HIGH COMPARED TO OTHER STATES ACHIEVING HIGH SAVINGS PERCENTAGE LEVELS?[49]

A. Dr. Stanton's point seems to be that, if Massachusetts, Vermont, and Rhode Island (the only three states achieving greater than 2% incremental savings in 2016)[50] can achieve savings of 2% for around $0.35 per kWh in any given year, ENO should be

[49] Stanton Direct at 34-35.

[50] Stanton Direct at p. 32, n.48; Exhibit SEC-20.

able to achieve that result, too. As I explained above, comparing ENO to other utility territories and states is not an apples-to-apples comparison because of differences in avoided costs, retail rates, program mix, market maturity, geography, climate, and customer mix.

Dr. Stanton, however, made no comparative analysis of those factors among ENO and those three northeastern, high achieving states. Nor did she include any analysis of the individual measure costs in Navigant's analysis to determine if any were unreasonable in her opinion. Moreover, she overlooks that recent program results have shown ENO is spending approximately $0.27 per kWh while achieving approximately 0.34% savings. Navigant, in its modeling to achieve 2% **for ENO**, had to assume that incentives cover 100% of a measure's total cost (which results in ~$0.60/kWh), very high marketing effectiveness, and administrative costs 50% higher than historic administrative costs due to the need for increased marketing. Thus, **for ENO**, it is not surprising that it was estimated to cost more to achieve 2% than it does for Massachusetts, Rhode Island, and Vermont. Comparison to those states is just not relevant to the determination of long-run efficiency potential in New Orleans.

Q34. MR. FAGAN ALSO ASSERTS THAT THE COMPANY SHOULD HAVE INCLUDED IN THE REFERENCE CASES THE PROJECTED SAVINGS ASSOCIATED WITH THE RECENTLY-APPROVED ENERGY SMART PROGRAMS FOR YEARS 7 THROUGH 9.[51] WHY WERE THOSE SAVINGS NOT INCLUDED?

A. The Company has already made reasoned decrements to its forecast to account for the current level of Energy Smart savings. Although Program Years 7 through 9 include programs designed to achieve incremental energy and peak demand reductions, the budget and incentive levels have yet to be approved.[52] Moreover, the Company has been spending more each year on Energy Smart programs, but savings have not increased. The Company's actual savings level is also consistent with or better than the level of savings actually being achieved in the southern states to which Navigant benchmarked its study results. Thus, it would be unreasonable to decrement a long-term reference case load forecast any further to account for future, unfunded near-term DSM programs. And as I explained earlier, the risk of decrementing the load forecast too much is that, if more load than forecast materializes, ENO's customers are subject to the risks of being completely reliant on an already heavily loaded transmission system, as discussed by Mr. Charles Long, and the short-term MISO PRA for capacity, which has already demonstrated potential for substantial price spikes from one year to the next.

[51] Fagan Direct at 7.

[52] Resolution R-17-176.

Q35. JOINT INTERVENORS WITNESSES STANTON AND FAGAN CRITICIZE THE COMPANY'S PROJECTIONS OF INCREMENTAL ROOF-TOP SOLAR INSTALLATIONS DURING THE PLANNING PERIOD.[53] CAN YOU COMMENT ON WHY THE COMPANY'S PROJECTIONS ARE REASONABLE?

A. Yes. The Company's projection that the rate of new rooftop solar installations will decline significantly is based on the unique circumstances that led to the remarkable growth of rooftop solar in New Orleans over the last few years as well as the uncertainty around whether customers who do not yet have rooftop solar will be willing to pay more than past customers as those circumstances change. Currently, all the customer-located behind-the-meter rooftop solar in New Orleans that is interconnected with the Company's system takes service pursuant to a tariff approved by the Council. As of August 2017, the clear majority of rooftop solar systems in New Orleans (~99.5%) were installed by residential customers and, thus, are billed using a mostly volumetric ($/kWh) rate that includes the majority of the Company's fixed and variable costs. The tariff, commonly referred to as "Net Metering," provides an offset to the customer's bill for all solar production that is consumed behind the meter, and any excess energy sent back to the grid is credited at the full retail rate. In addition to the full retail rate credit for solar production under the Council's current net metering policy, state and federal tax credits were combined to cover up to 80% of the cost of a typical rooftop solar system.

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[53] Stanton Direct at 15-19; Fagan Direct at 12-13.

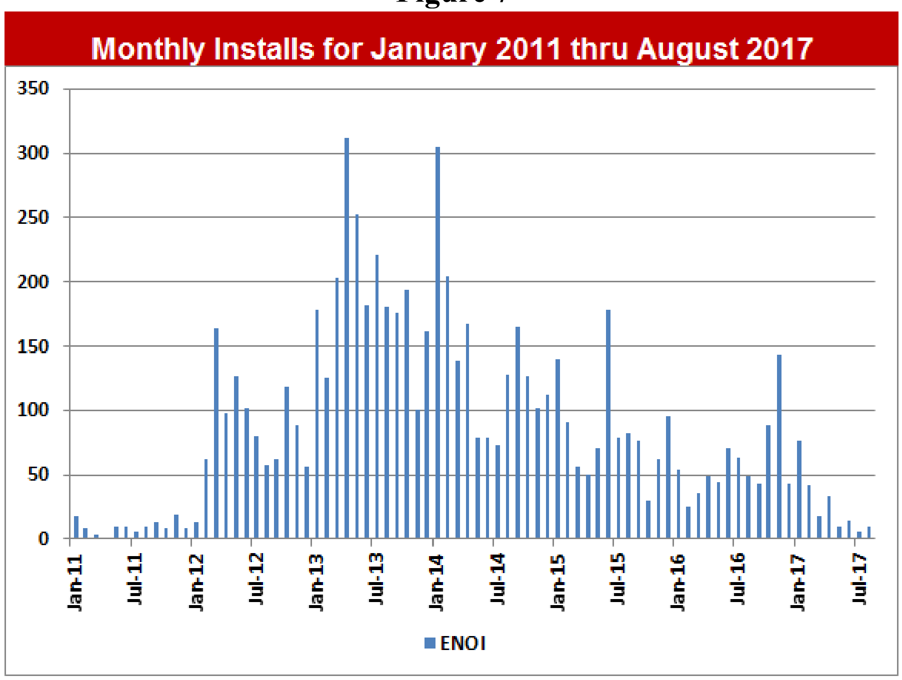
Currently, the refundable state tax credit for rooftop solar is no longer available except for a limited amount of funding for leased solar systems, which will end December 31, 2017.[54] In addition, on a more regional level, rooftop installation and marketing companies began offering systems in early 2012 at no upfront cost to the customer, where the installer would install, own, and maintain a rooftop system that the customer signs up for pursuant to a long-term lease. Federal and state tax incentives were combined by solar companies with leasing to attract more customers who were otherwise unable or unwilling to pay the upfront cost of a new system and reap the benefit of the 80% combined tax credit themselves. It was the confluence of these circumstances coupled with then-falling solar equipment costs that drove the significant growth in rooftop solar adoption in Louisiana, and especially in New Orleans, between 2013 and 2015. After the Louisiana legislature enacted policy changes in 2015, the number of rooftop solar systems installed in New Orleans began to decrease.

Going forward, the Company reasonably expects that the number of new installations will continue to decrease to a *de minimis* point following expiration of the existing state tax credit at the end of 2017 (and that is currently only available to solar leasing companies) and the phase-down of federal tax credits that will begin in 2020 and, ultimately, will significantly reduce the subsidies to customers and installation companies. As shown in Figure 7, the effects of these change are already evident because there are no funds remaining for customer-owned systems and the

[54] Per legislation enacted in 2015, Louisiana's refundable state tax credit was capped for leased and purchased solar systems at $25 million, respectively, and scheduled to sunset on December 31, 2017.

limited remaining funds available for leased rooftop solar systems will sunset by year end. Average monthly interconnections in New Orleans have fallen by ~86% in 2017 compared to their peak in 2013. Through August 2017, ENO has averaged ~26 interconnections per month.[55] These important circumstances unique to the recent slowing of growth in rooftop solar adoption in New Orleans were completely missed by Dr. Stanton because she made no independent effort to analyze any data specific to New Orleans.

Figure 7



Instead, in support of their position, Dr. Stanton and Mr. Fagan separately point to a few short articles of dubious authority to support their assertions about recent and projected declines in the national and global cost of solar panels. For example, Dr. Stanton cites to a Forbes article, which interestingly appears on the

[55] Per Company data adjusted for ENO's acquisition of Algiers in September 2015.

Forbes website in a section titled "Great Speculations." Further, the main point of the article she cites is that "Demand growth in the once-booming rooftop solar market in the United States appears to be leveling off, despite a reasonably healthy real estate market and strong consumer sentiment."[56]

Additionally, in Figure 6 of her Direct Testimony, Dr. Stanton points to research conducted by GreenTech Media ("GTM") that asserts rooftop solar has reached "grid parity" in Louisiana due to the conclusion that customer bill savings exceed the levelized cost of energy of rooftop solar. Upon closer review I note the GTM research that Dr. Stanton relies upon to produce Figure 6 does not provide the underlying data and calculations necessary to evaluate the reasonableness of the analysis she relies upon to make her assertion. Thus, it is unclear if the financial incentives that led to the rapid growth in rooftop solar in New Orleans between 2013 and 2015 have been accounted for in the GTM research that Dr. Stanton relies on to conclude expected customer bill savings will exceed the embedded cost of energy of a rooftop solar system. It is ironic that Dr. Stanton would argue that Louisiana, and New Orleans more particularly, are at so-called "grid parity," which would lend itself to increased adoption of rooftop solar systems, when the reality over the past two years shows quite the opposite – installations have fallen dramatically.

Notably, more recent material from the sources cited by Dr. Stanton contradicts much of her position. For example, the Q3 U.S. Solar Market Insight

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[56] Exhibit SEC-21.

Report,[57] a quarterly publication by GTM and the Solar Energy Industries Association (SEIA) that analyzes data on the U.S. solar market from nearly 200 utilities, state agencies, installers and manufacturers, projects the U.S. residential PV market to fall by 3% in 2017. The report cites customer acquisition challenges and changes to national residential solar companies' operations and sales strategies as reasons for the downturn. Per GTM, the cost for an installer to acquire a residential customer in the U.S. has continued to show a steady rise, going from $0.41 per watt in 2013 to $0.52 per watt in 2016.[58] GTM predicts another increase, to $0.56 per watt, for 2017.

More importantly, neither Dr. Stanton nor Mr. Fagan address the Complaint filed by Suniva under Section 201 of the Trade Act of 1974 with the U.S. International Trade Commission ("U.S. ITC") alleging unfair trade practices by foreign manufacturers of solar cells and solar modules.[59] The Complaint requests a tariff be imposed on all imported solar cells and modules. In an opinion issued September 22, 2017, the U.S. ITC ruled unanimously that imported solar panels had in fact caused harm to the domestic panel manufacturers. On November 14, 2017 U.S. ITC submitted its final report to the President, after which the procedural schedule calls for the President's final determination within approximately two months, which could be to grant or deny the recommended relief or make a different

[57] https://www.seia.org/sites/default/files/2017-09/USSMI-Q3-2017-Executive%20Summary.pdf.

[58] https://www.greentechmedia.com/articles/read/costs-to-acquire-us-residential-solar-customers-are-high-and-rising#gs.nsYZJoc.

[59] U.S. International Trade Commission Investigation No. TA-201-75 into Crystalline Silicon Photovoltaic Cells as amended and properly filed on May 17, 2017. This proceeding is discussed, but apparently ignored by Dr. Stanton, in one of the GTM articles that she references. The proceeding is discussed under the heading "America's new trade case is a crapshoot," and it says that the potential penalties resulting from the case "could result in the destruction of tens of gigawatts of solar installations in the U.S. through 2022." See Stanton Direct at n.22.

determination of what relief should be granted. Importantly, based on my understanding of the current market for panels, the risk of the petitioners' relief being granted at some level has already begun to be reflected in the market price for solar panels, which would most significantly affect the residential rooftop market given the small scale of individual systems and the sensitivity of that market to changes in cost. In fact, the Q3 U.S. Solar Market Insight Report referenced above mentions the current trade dispute initiated by Suniva as the primary downside risk to the U.S. solar outlook.

The point is that there are a number of circumstances that led to the remarkable growth in rooftop solar in New Orleans, such as generous state tax credits that are effectively exhausted and set to expire on December 31, 2017. Additionally, the pending trade case before the ITC presents the solar industry with the potential for a significant increase in the cost of solar panels, which could further depress demand for residential rooftop systems concurrently with elimination of state incentives and phase-out of federal solar tax incentives that begins in 2020. And even if the demand for new residential rooftop solar does not decline to zero, assuming some small number of installations each month would not have a material effect on the Company's analysis. The average size of residential rooftop solar systems being installed in New Orleans is about 5 kW, so a small number of new installations each month going forward, regardless of whether its zero or something slightly higher, would not have a meaningful impact on the Company's long-term resource needs.

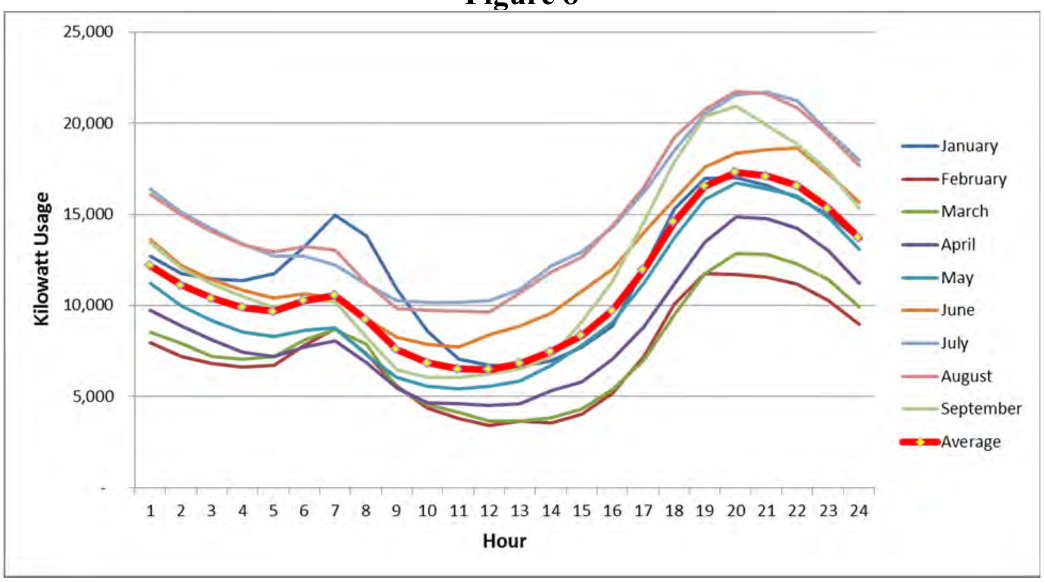
Q36. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Using the 50% capacity credit that MISO provides for utility-scale solar installations and applying that to a typical 5 kW rooftop system, one megawatt of capacity credit would require 400 residential rooftop systems. Based on the average number of installations per month through the first seven months of 2017, it would take nearly 1.5 years to total one additional megawatt of solar capacity credit. Given the expiring tax credits and the current declining trend in installations, that timeframe is likely understated. Thus, even if rooftop solar were capable of meeting the identified long-term need for peaking and reserve capacity, which it is not, Dr. Stanton's recommendation that the Company rely on the assumption that customers who do not yet have rooftop solar will spend more than customers who were able to take advantage of the expiring tax credits, especially in light of the trade case pending before the ITC, is extremely speculative and not the type of assumption that a prudent utility planner would rely upon.

Q37. ARE THERE ADDITIONAL CONSIDERATIONS RELATED TO THE IMPACT OF SOLAR ON LONG-TERM RESOURCE NEEDS?

A. Yes. Using metered data for a sample of the Company's Net Metered customers, Figure 8 shows the average load-profile of a typical Net Metered customer. As the chart indicates, rooftop solar production is at its highest during the early afternoon; however, as the sun begins to set solar production falls off at an exponential rate, at a time that coincides with the Company's daily peak. This is commonly referred to as the "duck curve" effect and is an important consideration for long-term planning as resources are required to quickly ramp up to replace the lost generation. During periods of inclement weather (*e.g.*, cloud-cover, thunderstorms) the duck curve can occur multiple times throughout the day. This holds true for utility-scale solar resources as well. Resources such as NOPS, on the other hand, are well-suited to help address the duck curve by providing a local quick-start, fast-ramping resource to balance the intermittency of solar generation, which will grow in importance as utility-scale solar resources are incorporated into the Company's portfolio.

Figure 8



Q38. WHAT CONCLUSIONS DOES DR. STANTON REACH ABOUT THE COST OF RENEWABLE RESOURCES, INCLUDING SOLAR?

A. While conducting no actual cost analysis, Dr. Stanton reaches seemingly contradictory conclusions. On the one hand she argues that "investment in capacity resources like NOPS is strongly dependent on assumptions regarding the expected future capacity price," presenting a "liability for ENO and an added cost burden for its customers."[60] Yet she also argues that the Company's planned investments in utility-scale solar, the additional solar capacity evaluated in the Requested Portfolios, and "facilitation of customer investments in behind-the-meter solar" could be used to reduce the Company's capacity deficit.[61] In her Figure 9, Dr. Stanton illustrates how those speculative assumptions combine to result in excess capacity without NOPS, by simply replacing NOPS with capacity from a combination of investments in utility-scale solar, increased DSM that may not prove cost-effective, and highly uncertain behind-the-meter rooftop solar. The economics behind the excess capacity resulting from these assumptions would rely on the same market price for capacity that Dr. Stanton argues presents a liability for customers if the excess results from NOPS.

Q39. DO DR. STANTON'S CONTRADICTORY CONCLUSIONS OFFER A VIABLE ALTERNATIVE TO NOPS?

No. The scenario that Dr. Stanton describes would actually expose customers to the market price for capacity to an even greater extent than NOPS by virtue of the total investment required to meet the identified need with utility-scale renewables, behind-the-meter solar, and DSM that may not be cost effective. Instead of investing in NOPS, the Company would have to invest in, or facilitate behind-the-meter customer investments in, anywhere from 2 MW of solar capacity to as much as 7 MW of wind capacity, respectively, to obtain 1 MW of capacity credit for purposes of meeting its overall long-term capacity shortfall. And to the extent excess capacity results from

60 Stanton Direct at 23.
61 Stanton Direct at 26.

investing in DSM that may not be cost-effective, customers would have paid for 2 to 7 MWs of renewables for every 1 MW of capacity credit while at the same time paying for efficiency gains where the costs may exceed the benefits.

Q40. DO YOU AGREE WITH DR. STANTON'S REVISED CAPACITY FORECAST REPRESENTED IN HER FIGURE 9?[62]

A. No. Dr. Stanton's forecast merely incorporates her unreasonable assumptions regarding DSM potential and behind-the-meter solar installations, plus ENO's planned 100 MW of utility-scale solar. Combining these three elements results in extremely speculative, best-case scenario adjustments that lack any analysis and cannot be the basis for prudent long-term resource planning decisions. They represent an extremely optimistic wait-and-see approach that relies on outcomes the Company has no control over or certainty around, and in any event, would not provide the same reliability or market- and supply-related risk mitigation as NOPS. ENO cannot base long-term resource planning decisions on such speculation.

[62] Stanton Direct at 22.

Q41. JOINT INTERVENORS WITNESS STANTON IMPLIES THAT ENO MISREPRESENTED ITS PROJECTED CAPACITY DEFICIT BY NOT ACCOUNTING FOR 100 MW OF PLANNED SOLAR RESOURCES.[63] IS THIS A CORRECT REPRESENTATION OF YOUR TESTIMONY AND EXHIBITS?

A. No. A basic tenet of resource planning is to identify needs before evaluating the impact of resource additions. Importantly, when taken as a whole, the information supporting NOPS as the best alternative to meet those needs dates back to the 2015 IRP. As the Council is well aware, the 2015 IRP Action Plan identified plans to issue an RFP to market-test the renewable resources evaluated in the IRP, which RFP is currently nearing completion. The inclusion of 100 MW of planned solar resources in the load and capability analysis that accompanied my Supplemental and Amending Direct Testimony (Exhibit SEC-11) reflects the Company's commitment to the Council to pursue up to 100 MW of renewable resources. However, that commitment should not be construed to supplant the analysis and conclusions reached in the 2015 IRP, or my Direct and Supplemental and Amending Direct Testimonies, that NOPS is the best alternative to meet the Company's long-term overall capacity deficit, including the substantial need for a local peaking and reserve resource that would provide the benefits discussed above.[64]

[63] Stanton Direct at 11-12.

[64] While the 2015 IRP acknowledged the declining cost of renewables (solar in particular), and evaluated different combinations of renewables that totaled 100 MW in capacity, all of the portfolios also included NOPS, which was consistent with the technology and economic analyses conducted in the IRP. The inclusion of renewables in the 2015 IRP was done to determine the ability of those resources to decrease production costs for the benefit of customers and further diversify the Company's generation portfolio.

Moreover, the analysis underlying both the 2015 IRP and my Direct Testimony assumed the larger CT resource is deployed, whereas my Supplemental and Amending Direct Testimony evaluated the original CT and a smaller Alternative Peaker. As the Council considers the merits of those options, it is important to understand that it would be inappropriate to evaluate the Company's long-term need as Dr. Stanton suggests. The Company committed to add up to 100 MW of solar, but the timing and location of those resources are still uncertain. Importantly, there are a number of uncertainties that support a measured approach to the amount and timing of additional potential solar additions (*e.g.*, outcome of the pending Suniva trade case). In contrast, NOPS has been established as the best among alternatives to meet an existing long-term capacity and reliability need, which alternatives do not include renewables such as wind and solar.

Q42. ACCORDING TO DR. STANTON'S ANALYSIS, INCLUDING 100 MW OF PLANNED SOLAR AND EITHER NOPS ALTERNATIVE WILL RESULT IN ENO CARRYING SOME AMOUNT OF EXCESS CAPACITY THROUGH MOST OF THE PLANNING PERIOD.[65] IS THAT AN UNREASONABLE SITUATION FROM A LONG-TERM PLANNING PERSPECTIVE?

A. No, especially in consideration of the Company's unique planning circumstances I described above. When making long-term resource planning decisions, it is appropriate to consider the entire planning horizon over which resource needs have

[65] Stanton Direct at 12.

been identified. Importantly, it is unreasonable to expect that resource additions can be perfectly matched to resource needs regardless of the technology under consideration, with which Advisors witness Mr. Rogers agrees.[66] In the case of NOPS, the Company has proposed two viable alternatives for the Council's consideration, where the CT would be expected to meet and slightly exceed the Company's target reserve margin over the planning horizon, and the Alternative Peaker would be expected to only meet that target for the first half of the planning horizon and thereafter leave the Company short. Selection of either option for NOPS would be a prudent way to meet the overall need for capacity, as well as mitigate the substantial peaking and reserve deficit. The additional capacity associated with the larger CT option would provide additional benefits to mitigate the market- and supply-related risks that I discuss in my Supplemental and Amending Direct Testimony, and which is reasonable in consideration of the unique planning circumstances I discuss therein and above. The smaller Alternative Peaker would provide similar benefits over the first half of the planning horizon.

Q43. IN YOUR OPINION, DID THE COMPANY MAKE REASONABLE ASSUMPTIONS WITH RESPECT TO ITS REFERENCE LOAD FORECAST?

A. Yes. The Company carries the obligation to serve load, and it must take a reasoned approach to long-term planning. It cannot rely on best-case scenarios and hope that circumstances outside of its control come to pass. Nevertheless, it is critical to

[66] Rogers Direct at 33.

understand that reasonable adjustments were made in the forecasting process that address the issues the Joint Intervenors claim are lacking. It is also important to understand that the Company's load forecast was not prepared solely for this proceeding but is part of a broader purpose that includes being the basis upon which management makes financial decisions and financial plans for the Company. Thus, it is critical that the forecast, which is prepared by specialists at ENO's service company, Entergy Services, Inc., include adjustments based only on reasonable assumptions.

To that end, the forecast includes the effects of Energy Smart programs through Program Year 6, the last full year for which data is available, based on the effects those programs actually had on billed sales. Moreover, embedded within the load forecast are the estimated effects on the Company's sales and peak demand associated with a range of factors that are inherently uncertain. Those factors include the assumption that historical savings from Company-sponsored energy efficiency programs will continue at the same level, historical customer behavior, historical voluntary customer efficiency investments, and historical performance of customer investments in behind-the-meter technologies (*e.g.* smart thermostats and rooftop solar). The assumption that those improvements, investments and behaviors will continue to provide the same levels of sales and peak demand reduction over a long-term planning horizon, especially considering the continued growth in customer count, is uncertain and requires ongoing sustained investments.

The forecast also includes an annual reduction in projected sales that reaches 1.5% in 2022 to account for the anticipated effect of the proposed deployment of

AMI across the Company's service area, which docket is still pending before the Council. The assumption that AMI will permanently reduce customer usage is also uncertain and depends on customer behavior. While, as Dr. Stanton and Mr. Fagan note, the Company did file an implementation plan designed to target an increased level of savings for Program Years 7 – 9 of Energy Smart, those goals are significantly higher than the savings results the Company has achieved through the first six years of Energy Smart despite annual increases in program spending, and moreover, the Council has not approved the Company's proposed funding levels or a dedicated recovery mechanism to recover program costs.

The point is that the load forecast already assumes reductions in future demand associated with historical factors, changes in customer behavior, and prospective investments that are not certain to continue providing the estimated savings over a long-term planning horizon, but the Company has assumed they will continue and are included in the current load forecast. Including ***additional*** reductions based on speculative best-case scenarios as proposed by Dr. Stanton and Mr. Fagan would not be reasonable and would expose the Company's customers to price risks in the market as well as reliability risks if the speculative decrements do not materialize as assumed, which is also discussed by Company witnesses Charles Long.

Q44. ALTHOUGH YOU HAVE DESCRIBED ADJUSTMENTS FOR CIRCUMSTANCES THAT HAVE THE EFFECT OF REDUCING LOAD IN THE FORECAST, ARE THERE EXAMPLES OF CIRCUMSTANCES THAT COULD

INCREASE THE COMPANY'S PROJECTED NEED BUT WERE NOT INCLUDED IN THE FORECAST?

A. Yes. The Company's load forecast does not include any adjustments for potential increases that could materialize if the economy expands more strongly than forecast, which could increase growth in customer count, load, or both. The forecast also does not include the potential for adoption by customers of electric vehicles ("EVs") that would increase the Company's load as those vehicle's batteries are charged.[67] The forecast also assumes that existing rooftop solar will continue providing the same level of load reduction over the planning horizon, which does not account for degradation in the production of solar panels over time, and also assumes customers will continue maintaining their systems in good operating condition and minimize shading from adjacent vegetation. Accordingly, considering that adjustments to the forecast were made for potential decreases but none were made for potential increases, the Company believes that any additional decrements, along the lines suggested by the Joint Intervenors witnesses, would be extremely risky and irresponsible considering ENO has an obligation to be prepared to reliably serve whatever load actually materializes.

The Company's need for more generating capacity could also stem from unexpected reductions in the rated capacity of existing resources. For example, the results of generator verification tests ("GVTC"), which are performed to calculate a

[67] It is worth noting that on September 28, 2017 the Council adopted Ordinance No. 31953, which ordained changes to Code of the City of New Orleans providing for the requirements to permit the installation of curbside EV charging stations in public right of way. On October 11, 2017, the Mayor approved and returned the Ordinance, and in accordance with Section 3-113(2) of the Home Rule Charter, the Ordinance became effective on October 9, 2017.

unit's unforced capacity (UCAP) for purposes of MISO's resource adequacy processes, can change annually. In fact, for upcoming PY18-19 the Company will recognize a 21 MW reduction in available generating resources due to a newly calculated GVTC for the Company's Union Power Station generating facility. Ultimately, when compared to the Company's electrical load, this results in an unexpected reduction in available capacity that is not reflected in my Exhibit SEC-11. In fact, while I explained in my Supplemental and Amending Direct Testimony that the difference in load forecasts between the initial application and the Supplemental Application was a reduction of approximately 40 MW in peak demand,[68] the reduction in the Company's generation capacity as a result of the most recent GVTC test results negates over half of the effect of the load reduction on the Company's overall capacity need.

Q45. IN HIS FIGURE 3, ADVISORS WITNESS ROGERS PRESENTS A REVISED EXHIBIT SEC-11, WHICH PRESENTS A REDUCED CAPACITY NEED OF 92 MW IN 2036.[69] DO YOU AGREE WITH MR. ROGERS'S ADJUSTMENTS?

A. No. Mr. Rogers's adjustment simply includes the assumed effect of modifying the Company's load forecast to include the Council's 2% DSM goal. As Mr. Rogers points out, the Company's forecast of load has declined since the Final 2015 IRP due to decreases in customer demand associated with historical energy efficiency gains and behind-the-meter rooftop solar. Additionally, the current forecast includes

68 Cureington Supplemental and Amending Direct at 3.

69 Rogers Direct at 12, Figure 3.

further downward adjustments by the Company to reflect full deployment of AMI. As illustrated by Figure 1 in Mr. Rogers's testimony, the direct and indirect reductions to the Company's load forecast have been significant. As I discussed at length above, no one in this proceeding has offered any evidence that the Council's 2% goal is achievable, sustainable, and cost-effective over a long-term planning horizon. To the contrary, Navigant's analysis indicates that it is not. Thus, further decrementing the load forecast to include that goal would be extremely speculative and unreasonable. Moreover, like the Joint Intervenors, Mr. Rogers ignores potential factors that may increase long-term demand.

Q46. JOINT INTERVENORS WITNESS FAGAN CLAIMS THAT ENO'S PROJECTED LONG-TERM CAPACITY DEFICIT IS NOT ENOUGH TO JUSTIFY THE ADDITION OF A NEW RESOURCE AND THAT ENO SHOULD INSTEAD RELY ON MISO'S CAPACITY MARKET.[70] IS HIS SUGGESTION REASONABLE FROM A LONG-TERM PLANNING PERSPECTIVE?

A. No. Mr. Fagan argues in favor of exposing customers to the market price for capacity over a long-term planning horizon based on the mere observation that the annual prices are low today, his assumption that equilibrium is not likely to occur because of potential capacity additions in MISO, and the speculative conclusion that Navigant's High Case Achievable level of DSM materializes. In fact, in making his argument, Mr. Fagan does not address Navigant's conclusion that the assumptions underlying its

[70] Fagan Direct at 16-17, 31-32.

High Case Achievable level of DSM are aggressive and would not yield a sustainable annual savings level for the duration of the planning horizon.[71] Mr. Fagan's speculation also fails to address that the energy efficiency programs implemented by the Company over the last six years, which are largely consistent with the programs modeled by Navigant, have produced only about half the maximum achievable savings level (0.85%) estimated by Navigant, despite increased annual funding of those programs. Moreover, Mr. Fagan concludes his speculative argument by asserting that "ENO should fully utilize the transmission system capability when seeking to meet capacity requirements" that are not addressed by DSM when in fact my Direct and Supplemental and Amending Direct Testimonies make clear the Company is over-reliant on the transmission system today. In the HSPM Table 1 below, I summarize the different ways in which this over-reliance has been characterized in my prior testimonies.[72]

[redacted]

[71] Exhibit SEC-14 at 22.

[72] Cureington Direct at 23 (Table 4); Cureington Supplemental and Amending Direct at 23.

Q47. MR. BRUBAKER RECOMMENDS THAT ENO CONSIDER BUILDING THE INFRASTRUCTURE TO ACCOMMODATE ALL SEVEN RICE UNITS, BUT NOT INSTALLING ALL SEVEN AT THIS TIME. WHAT IS THE COMPANY'S RESPONSE TO THAT RECOMMENDATION?

A. The Company has considered the recommendation and does not agree that the cost impact to customers ultimately would be less if the Company built out the infrastructure to accommodate seven 18 MW Wartsila units but only installed four or five units now. Although ENO is not proposing to install only four or five units now, and accordingly does not have a fully developed cost estimate for such a project, economies of scale were found to exist during the development of the Alternative Peaker. In other words, it should be expected that installing fewer than seven units would cost more on a dollar-per-kW basis than a seven-unit plant. Furthermore, the infrastructure build out that Mr. Brubaker recommends would obviously be more extensive and costly than for a four or five unit site, and it is not clear that the costs of mobilizing contractors to the site for a second time in the future and obtaining any necessary regulatory approvals would support delaying the installation of two or three units from an economic standpoint.

More importantly, based on the Company's demand forecast for the next 20 years, ENO is projected to have an overall capacity needs of approximately 100 MW for the first ten years of the planning horizon, but that need is projected to more than double in second decade of the planning period. Accordingly, ENO will ultimately need the full 128 MW of capacity that the seven-unit Alternative Peaker would provide, and, as I discussed in my Supplemental and Amending Direct Testimony, the

Company's resource needs could increase sooner than forecasted if existing legacy units included in the Company's portfolio deactivate earlier than expected or load increases more than projected due to the adoption of new technologies (*e.g.* electric vehicles). Although the Company has recognized that the Council may prefer the Alternative Peaker to the CT if it wishes to delay some capacity expansion as Mr. Brubaker recommends, reducing the capacity of the Alternative Peaker is not justified considering ENO's long-term needs and the expected reliability benefits of the seven-unit plant.

VI. ECONOMIC ANALYSIS

Q48. HOW DO YOU RESPOND TO JOINT INTERVENORS WITNESS FAGAN'S GENERAL CRITICISM THAT "ENO DID NOT PERFORM A SUFFICIENTLY RIGOROUS ANALYSIS"?[73]

A. It is misplaced and ignores the process the Company followed leading up to and during this proceeding. It all began with the 2015 IRP filed in February 2016 (Exhibit SEC-7 to my Direct Testimony). The IRP documented the extensive analysis undertaken, and stakeholder input sought, over the course of nearly 18 months of work that resulted in the conclusion that the Company has a substantial need for peaking and reserve capacity, and that a CT is the lowest reasonable cost resource capable of meeting that need. The modeling undertaken as part of the IRP

[73] Fagan Direct at 9, 11-15.

involved hundreds of hours of data review, modeling, post-processing analysis, and stakeholder review, as well as public technical conferences and reports to the Council.

In fact, the type of analysis described by Mr. Fagan that he believes should be conducted is consistent with the type of analysis undertaken in the 2015 IRP, or any IRP for that matter, which is designed to consider a wide range of different future scenarios and resource alternatives. Once the Company established both the need and the lowest reasonable cost resource to meet that need, it was reasonable to then narrow the scope of the analysis to optimize the selection of a resource type, in this case peaking resources, from a list of proven and viable equipment manufacturers.

In my Direct Testimony I provided an update to the technology evaluation included in the 2015 IRP (Exhibit SEC-5), which evaluated a range of peaking technologies consistent with the findings in the 2015 IRP. That analysis then formed the basis of the detailed economic evaluation that compared the economics of building the larger CT to building a smaller aero-derivative gas turbine and deferring the addition of a second smaller unit until later in the planning horizon (Exhibit SEC-6).

Subsequent to that analysis, the Company conducted numerous detailed supplemental economic evaluations as presented in my Supplemental Direct Testimony and Supplemental and Amending Direct Testimony. Those analyses include the results of production cost modeling utilizing different assumptions around gas prices, capacity prices, DSM, renewable resources, and two gas-fired resources. Mr. Fagan's argument that the Company's analysis supporting its application lacks rigor should be rejected. The analysis supporting the need for a new generating resource has been in development for roughly three years now, and NOPS continues to prove to be the best resource alternative for meeting ENO's specific long-term needs, notwithstanding that, as Mr. Rogers notes, conditions have changed since the 2015 IRP process began.[74]

Q49. DOES MR. FAGAN VOICE OTHER CONCERNS ABOUT THE COMPANY'S ECONOMIC ANALYSIS?

A. Yes. Mr. Fagan goes on to complain that the economic analysis is flawed because it failed to incorporate least-cost energy efficiency resources and it relies on capacity prices that are too high.[75] He also criticizes ENO for "self-selecting" a set of scenarios that do not include, in his view, reasonable mixes of renewable resources, DSM, and behind-the-meter resources.[76] I addressed those points above, but as a general matter I note that he did not conduct any analysis of his own, and he does nothing but propose speculative, unsupported ideas for ways that might reduce ENO's forecasted peak load and then urges the Council to gamble that MISO will remain in a surplus position throughout the planning period, despite the fact that MISO, MISO's IMM, and NERC all project a capacity deficiency in coming years.

Mr. Fagan offers scant to no support for his positions beyond citations to macro-level information not specific to ENO or its unique planning circumstances, and ENO cannot rely on such speculation in assessing its long-term needs,

[74] Rogers Direct at 14-18.
[75] Fagan Direct at 11.
[76] Fagan Direct at 12.

recognizing that it has an obligation to serve whatever load materializes. Moreover, ENO has made adjustments for the issues raised by the Joint Intervenors, but in a measured, reasonable manner. Further, ENO conducted analyses in the Requested Portfolios, which were supported by the Joint Intervenors,[77] that tested the Joint Intervenors witnesses' theories, and NOPS still proves to be the best alternative for addressing ENO's needs, especially considering the local reliability, storm response, and the energy and capacity market hedge it provides. In fact, even under the combined sensitivity of low capacity prices and high gas prices, the total relevant supply cost of the Requested Portfolios that include NOPS (Case 3 and 3G) are not materially different from that of Case 4A (solar) and Case 4B (wind).

Q50. IN DISCUSSING THE RESULTS OF THE ECONOMIC ANALYSES, ADVISORS WITNESS ROGERS CLAIMS THAT QUESTIONS REMAIN AROUND THE COMPANY'S RESPONSE TO ADVISORS DATA REQUEST 14-1 BECAUSE THERE WERE "CHANGES THAT WERE CURIOUSLY INCLUDED BUT NOT REVEALED OR EXPLAINED IN THE INITIAL DISCOVERY RESPONSE."[78] DO YOU AGREE?

A. Mr. Rogers is referring to the identification of an error in the Company's modeling of the CT alternative in which the value of make-whole payments, which is part of the variable supply costs calculation, was inadvertently doubled. Mr. Rogers questions

[77] Alliance for Affordable Energy, Deep South Center for Environmental Justice, Inc., and Sierra Club's Response to Advisors' Recommendations with Respect to ENO's New Orleans Power Station Supplemental Filings; Docket No. UD-16-02 (April 13, 2017).

[78] Rogers Direct at 26-27.

why that error did not have a significant effect on the overall rankings of the various alternatives. Despite his assertions that there were unexplained changes included in the updated results, the workpapers provided in the Company's response to Advisors' 14-1 made clear that the error impacted both variable supply costs and revenues equally such that the correction simply resulted in a slight decrease in the present value of the total relevant supply costs presented in Exhibit SEC-13. That is why there was not a significant effect on the overall results.

Q51. ADVISORS WITNESS ROGERS COMMENTS ON PAGE 29 OF HIS TESTIMONY THAT IT IS NOT HELPFUL TO COMPARE THE TWO SETS OF CASES, *I.E.*, THE COMPANY'S REFERENCE PORTFOLIOS AND THE REQUESTED PORTFOLIOS, UNLESS THEY HAVE IDENTICAL GENERATING PORTFOLIOS. DO YOU HAVE ANY COMMENT?

A. Such a comparison was not intended. The Company believes that the Reference Portfolios should guide the Council's determination in this case. As I explained in my Supplemental and Amending Direct Testimony as well as at length above, the Requested Portfolios include unreasonable assumptions around the achievable level of DSM, MISO capacity prices, and inclusion of renewable resources that are not viable for addressing ENO's need for peaking and reserve capacity or addressing the current reliability issues.

Q52. ADVISORS WITNESSES ROGERS AND WATSON PRESENTED REVISIONS TO THE COMPANY'S ECONOMIC ANALYSES THAT CALCULATE THE

TOTAL RELEVANT SUPPLY COSTS ON A NON-LEVELIZED BASIS (MR. ROGERS'S TABLES 4 AND 5).[79] DO YOU AGREE WITH THAT ADJUSTMENT?

A No. The Company disagrees with the assertion that it is inappropriate to use the levelized calculation when assessing total relevant supply costs of different portfolios. In fact, as Mr. Rogers notes, the differences in the amount and timing of capital expenditures between different resource portfolios is one of the primary reasons for using the levelizing calculation so as not to skew the results based simply on timing differences associated with capital outlays necessary to construct each resource. And in any event, the methodology is commonly used in the industry when comparing alternatives of different terms or economic useful lives and consistent with the revenue requirement calculation that spreads the return of an on the investment over its depreciable life. Nonetheless, based on the Company's Reference Portfolios and reference capacity price forecast, the results of the Advisors' analysis still indicate that the CT is the most economic choice. The results are different for their revised Recommended Portfolios, but those suffer from inclusion of the 2% DSM goal reduction to the load forecast.

Q53. HOW DO YOU RESPOND TO THE ADVISORS' SECOND SET OF REVISED ANALYSES (MR. ROGERS'S TABLES 6 AND 7), WHICH UTILIZED NON-

[79] Rogers Direct at 42.

LEVELIZED COSTS AND A SUBSTANTIALLY REDUCED CAPACITY FORECAST?[80]

A. Those analyses are not reasonable because they incorporate a completely arbitrary assumption of a $6/kW-year capacity price increased only by a general economic inflation factor, which assumes that MISO PRA clearing prices will remain extremely low, essentially flat in real terms over the 20-year planning horizon. As I explained above, that is contrary to the position of the Company, MISO, the MISO IMM, IHS, and NERC. I also explained above why past PRA clearing prices are meaningless in terms of trying to predict future clearing prices, particularly as the capacity surplus declines. The analyses presented in Mr. Rogers's Table 7 suffer from those same defects plus the assumption that the Council's 2% DSM goal is achievable and sustainable. Those analyses should be rejected because the assumptions are unreasonable for all of the reasons I have discussed.

Q54. IN MR. WATSON'S TABLE 5, HE RECALCULATES TYPICAL BILL IMPACTS BASED ON THE ADVISORS' REVISED ECONOMIC ANALYSES. DO YOU HAVE ANY CONCERNS WITH HIS CALCULATIONS?

A. Yes. Mr. Watson's revised bill impacts indicate that the transmission-only case is significantly less expensive than the NOPS alternatives. That result, however, is obtained from using the non-levelized total relevant supply cost and the unreasonably low capacity price forecast provided by Mr. Rogers. Because those analyses are

80 Rogers Direct at 44.

fatally flawed through the inclusion of a speculative capacity price forecast that is entirely inconsistent with the substantial evidence put forth in this proceeding by the Company of equilibrium occurring around 2022, Mr. Watson's bill impacts are not reasonable. The Company's calculations shown on page 13 of Mr. Watson's testimony remain the most relevant indication of the bill impacts of the various alternatives for purposes of comparing the Company's Reference Portfolios.

Q55. HOW DO YOU RESPOND TO MR. ROGERS'S ARGUMENT THAT HIS POSITION ON CAPACITY MARKET RISK IS ANALOGOUS TO THE COMPANY'S CONCERNS IT STATED IN THE 2015 IRP THAT CONSTRUCTING A COMBINED CYCLE GAS TURBINE ("CCGT") TO ADDRESS ITS PEAKING AND RESERVE CAPACITY NEEDS WOULD EXPOSE CUSTOMERS TO ENERGY MARKET RISK?

A. Insofar as he has characterized this issue and its relation to NOPS, Mr. Rogers misunderstands the Company's arguments in the IRP. In the IRP, the Company established it had a need for capacity, not energy. Accordingly, AURORA's selection of a baseload or load-following resource such as a CCGT was inconsistent with the identified needs. As identified in the Final 2015 IRP, as well as my Direct and Supplemental and Amending Direct Testimonies, the Company has a substantial peaking and reserve capacity deficit that exceeds the size of the CT. Thus, it is reasonable that in both the 2015 IRP and the instant proceeding the Company has proposed a peaking resource capable of meeting a substantial portion of the identified need, even if the result is not perfectly aligned with the Company's overall capacity need. As Mr. Rogers acknowledges, "[o]bviously, ENO cannot exactly build to meets its Resource Adequacy Requirements each year,"[81] and in consideration of the Company's long-term overall capacity need of approximately 250 MW and over 300 MW peaking and reserve capacity deficit, it is not reasonable to conclude that customers would be exposed to the capacity market with the addition of NOPS in the same way as they would be exposed to the energy market if the Company built a CCGT instead, simply because the Company has identified a need for peaking and reserve capacity which NOPS, not a CCGT, is designed to address.

Q56. HOW DO YOU RESPOND TO MR. FAGAN'S CLAIMS THAT, "WHEN ENO MODELS A MORE REASONABLE ESTIMATE OF MISO'S CAPACITY CLEARING PRICE, A TRANSMISSION-ONLY APPROACH IS THE MOST COST-EFFECTIVE OPTION"?[82]

A. Mr. Fagan's claim misses the forest for a single tree. Even assuming capacity prices that are 40% less than the Company's projections, the transmission-only case is less than one percent more cost effective than the CT option under the reference and high gas cases, and the transmission-only case is less cost-effective than the CT option under the low gas case.[83] In fact, NYMEX projections are currently tracking closer to the low gas sensitivity. The RICE alternative is within four percent of the transmission-only alternative in all three gas sensitivities. Accordingly, for roughly

81 Rogers Direct at 33.

82 Fagan Direct at 10, 36-37.

83 Cureington Supplemental and Amending Direct at 29.

the same cost, it is not reasonable to select the transmission-only option that would not meet the capacity need nor provide the benefits I describe above.

The same essentially holds true under the Company's projected capacity prices. The CT's advantage over the transmission-only case is slightly greater in all three gas sensitivities, and the gap between the RICE units and the transmission-only case narrows to less than two percent. Thus, again, from a total supply cost basis, it is a virtual tie, **but the transmission upgrades would not provide the reliability benefits needed by New Orleans and would not meet the identified need for a local source of peaking and reserve capacity**. Mr. Charles Long addresses the reliability benefits of the local generation in more detail.

Q57. HOW DO YOU RESPOND TO MR. FAGAN'S ASSERTION THAT BATTERY STORAGE IN COMBINATION WITH ENERGY EFFICIENCY AND SOLAR PV WOULD REDUCE PEAK LOADS AND REDUCE TRANSMISSION REINFORCEMENT NEEDED TO MEET NERC RELIABILITY STANDARDS, THUS MAKING TRANSMISSION INVESTMENT A BETTER CHOICE?

A. Again, Mr. Fagan is relying on a string of assumptions that amounts to a risky gamble that everything in New Orleans will work out as he speculates based on generic national and global purported trends. However, neither Mr. Fagan nor Dr. Stanton provide any credible information specific to New Orleans that battery storage is economic, let alone whether it could effectively meet **ENO's** peaking needs. I also addressed above why it would be unreasonable to decrement the load forecast more than ENO has already done to account for extremely optimistic assumptions with respect to continued solar roof-top solar growth when the subsidies end and in the shadow of potential trade tariffs. I also explained that decrementing the load forecast for more DSM would be unreasonable given ENO's program history to date. Thus, ENO has taken a reasonable approach to these issues, whereas Mr. Fagan and Dr. Stanton would potentially expose ENO's customers to increased reliability problems if their assumptions prove incorrect and ENO were to find itself with more load than the transmission system can support. Further, in that scenario, building a resource to solve the problem would take several years, during which time ENO's customers would be exposed to higher LMPs given the congested transmission system, higher capacity prices given ENO would be completely reliant on the MISO capacity market for its needed incremental capacity, potential NERC fines, and potential cascading power failures. That risk can be mitigated with NOPS while simultaneously meeting the identified need for a long-term local source of peaking and reserve capacity that provides the benefits I describe above, all for the same cost or less than a short-term transmission fix.

Q58. WILL NEW TRANSMISSION INVESTMENT IN MISO AS A WHOLE ALLOW ENO MORE ACCESS TO RESOURCES IN MISO?

A. Mr. Fagan makes this claim,[84] but it is unfounded, and he offers zero analysis to support his assertions. New transmission in MISO does not automatically result in additional capacity being available to MISO South and then to DSG in particular. In

[84] Fagan Direct at 30.

any event, as I articulate above, the Company's over-reliance on transmission to serve load today makes Mr. Fagan's argument here moot. This is more wait-and-see speculation that places considerable risk on ENO and its customers.

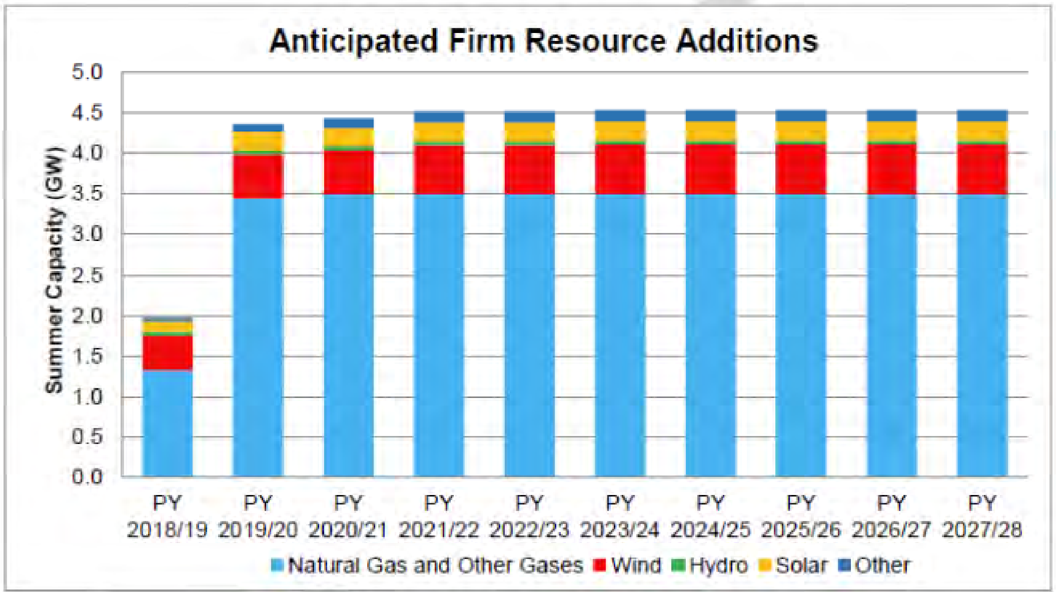
VII. TECHNOLOGY SELECTION

Q59. HOW DO YOU RESPOND TO MR. FAGAN'S CLAIM THAT "AS AGING AND UNECONOMIC COAL PLANTS RETIRE, CAPACITY OBLIGATIONS WILL BE MET WITH DEMAND-SIDE RESOURCE ADDITIONS (THE EFFECT OF INCREASING ENERGY EFFICIENCY AND AVAILABLE DEMAND RESPONSE RESOURCES), BEHIND-THE-METER RESOURCES (ESPECIALLY SOLAR PHOTOVOLTAIC), AND AVAILABLE NEW WIND, STORAGE, AND TO SOME EXTENT GAS-FIRED RESOURCES"?[85]

A. Mr. Fagan has it backwards. Most utilities are planning to meet their demand and reliability needs with gas-fired resources. DSM, renewables, and distributed generation are being added in a measured approach to further diversify resource portfolios. This position is illustrated in the MISO Transmission Expansion Planning ("MTEP") report cited by Mr. Fagan. As seen in Figure 9, below, over 75% of the anticipated firm resource additions in MISO are expected to be natural gas.

[85] Fagan Direct at 23.

Figure 9[86]



Q60. HOW DO YOU RESPOND TO DR. STANTON'S CHARGE THAT GAS PEAKERS ARE AMONG THE MOST EXPENSIVE ALTERNATIVES GIVEN THEIR TYPICALLY LOWER CAPACITY FACTOR?[87]

A. Dr. Stanton's argument is factually wrong and lacks the appropriate context. When measured in terms of cost of energy, gas-fired peaking technology is typically higher per megawatt-hour when compared to generating technologies that have higher capacity factors and/or greater efficiency. However, the Company's identified need

[86] Exhibit SEC-17 at 16, Figure 6.2-1.

[87] Stanton Direct at 41-43.

is for peaking and reserve capacity, not energy.[88] For that reason, a more relevant metric in evaluating the cost to meet a peaking and reserve capacity need is the installed cost of the generating unit per unit of capacity. Even if renewables such as solar and wind were capable of serving in a peaking and reserve capacity role, which they are not, the Company would have to invest in 2-7 times more MWs of solar and wind respectively to equal the same amount of MWs provided by NOPS. Thus, even if the cost of solar and wind were equal to NOPS on a $/kW basis, the Company would have to invest significantly more in total to meet the identified need than otherwise necessary.

Q61. WHAT IS THE RELEVANCE OF DR. STANTON'S REFERENCE TO RECENT CALIFORNIA DECISIONS ON TWO PEAKER UNITS?[89]

A. None. ENO's request should be based on its unique needs and operating environment, and the Council's focus in rightly on how to reliably and economically serve New Orleans power needs. Nonetheless, I would point out that Dr. Stanton's statement regarding the Puente plant is not correct. The California Energy Commission Committee of the Energy Resources Conservation and Development Commission did provide notice that it planned to recommend against approving the

[88] Dr. Beverly Wright states in her Direct Testimony that only 15% of NOPS's operations would serve New Orleans customers, citing generally to my Direct Testimony. *See* Wright Direct at 10. Nowhere in my testimony; however, did I make such a statement. Rather, I simply defined the peaking requirement as the level of load that is served in the highest 15% of hours of the year. *See* Cureington Direct at 17. Thus, my testimony and the air permit application that Dr. Wright mentions in her testimony do not support her contention that "the majority of the plant's operations would be to generate electricity for users outside of New Orleans on the MISO grid." *See* Wright Direct at 9.

[89] Stanton Direct at 43.

Puente plant,[90] but the proceeding has been suspended for six months.[91] Further, should the Committee eventually offer a recommendation to deny the plant, it would then go before the full Commission to either accept, reject, or modify the Committees' recommendation.[92]

Q62. DR. STANTON CHALLENGES ENO'S IDENTIFIED NEED FOR A PEAKING RESOURCE, CLAIMING THAT CONSIDERATION OF ENO'S USE OF SUPPLY ROLES IN PLANNING IS "OUTDATED" AND NOT USEFUL OR RELEVANT IN DETERMINING ENO'S LONG-TERM RESOURCE NEEDS. IS THAT ACCURATE?

A. No. The goal of prudent resource planning is to identify a portfolio of resources capable of cost-effectively serving the time-varying customer demand while mitigating market- and supply-related risks. As discussed in my Direct and Supplemental and Amending Direct Testimonies, this requires an analysis of how the supply roles of resources included in the Company's portfolio compare to the Company's load-shape. Contrary to Dr. Stanton's argument, such an approach is not outdated but rather a fundamental part of the long-term planning process. In fact, Dr. Stanton concedes that the objective of resource planning is to acquire cost-

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90 Committee Statement Regarding the State of Presiding Member's Proposed Decision, *Application for Certification for the: Puente Power Project*, Docket No. 15-AFC-01 (October 5, 2017).

91 Committee Order Granting Applicant's Motion to Suspend Denying Intervenors' Application to File Supplemental Response, *Application for Certification for the: Puente Power Project*, Docket No. 15-AFC-01 (November 3, 2017).

92 Committee Statement Regarding the State of Presiding Member's Proposed Decision, *Application for Certification for the: Puente Power Project*, Docket No. 15-AFC-01 (October 5, 2017).

effective, flexible and reliable supply- and demand-side resources,[93] which would not be possible without first understanding the time-varying levels of customer demand and the different technologies and their associated operating characteristics and cost in order to identify those resources best suited to serve those needs. If such an approach were "outdated" and unnecessary, resource planners would simply add supply- and/or demand-side resources to meet long-term needs irrespective of the operating characteristics or cost of the technology. Such an approach would be a ridiculous method for assessing and attempting to meet long-term resource needs.

Q63. DOES DR. STANTON PROVIDE ANY SUPPORT FOR HER POSITION?

A. In support of her argument, Dr. Stanton states that "ENO does not need to balance each of these three categories' separately."[94] Instead, Dr. Stanton points to MISO and other Independent System Operators to argue that because these entities do not consider load shape or supply-role characteristics, and instead consider a total reserve requirement by capacity zone, ENO should similarly not be concerned with looking beyond its overall capacity need.[95] Dr. Stanton goes on to argue that because of increases in technology, "the more modern approach is to emphasize the acquisition of both supply- and demand-side resources that are cost-effective, flexible and reliable in order to help the electric grid operate most efficiently."[96]

[93] Stanton Direct at 10-11
[94] Stanton Direct at 9.
[95] Stanton Direct at 10.
[96] Stanton Direct at 10-11.

While I agree that it is important to deploy cost-effective and reliable resources, I disagree with Dr. Stanton's conclusion that because there were fewer technology choices available historically that necessitated such designations, the Company can ignore supply-role needs in its planning process today. The mere fact that new technologies are being contemplated that will increase the range of alternatives available to meet customers' needs does not render consideration of supply-role needs moot. In fact, because the number of alternatives that can impact the time-varying shape of customer demand are increasing, consideration of the Company's load shape and how the operating characteristics of the Company's existing supply-side resources compare will become more important as those new technologies are adopted.

For example, if utility-scale battery storage becomes cost-effective over the planning horizon, one of the primary use cases would be to arbitrage the difference between on-peak and off-peak LMPs by charging the batteries during off-peak hours when LMPs are low and discharging them on-peak when LMPs are relatively higher. Such a scenario would tend to increase the Company's off-peak load and decrease the amount of on-peak load. Were the Company to ignore the impact this could have on its load shape, it would have no basis to determine whether the existing supply role of its generating portfolio (*e.g.*, baseload, load-following, peaking and reserve) would be sufficient to cost-effectively meet those time-varying needs.

Dr. Stanton also misunderstands MISO's role as it relates to resource adequacy within its footprint, which is to determine an adequate annual reserve requirement for each Local Resource Zone and administer the annual Planning

Reserve Auction process. MISO's obligations as grid operator to maintain reliability of the bulk electric system acts much like an air-traffic controller whose charge is to direct the flow of air traffic, manage congested airspace to avoid unsafe conditions, and ensure the most efficient use of finite resources, namely runways. Similarly, MISO dispatches available generation to enable efficient use of the electric system while managing congestion on transmission lines to avoid unsafe conditions that could compromise reliability of the bulk electric system. MISO's role in coordinating dispatch while maintaining reliability relies on an overall planning reserve requirement simply because MISO's obligations do not extend to resource planning for LSEs. MISO correctly leaves that determination to the individual LSEs and their retail regulators, as each LSE's planning circumstances are different and limiting planning analysis to an overall planning reserve requirement would ignore how each LSE's unique planning circumstances influence long-term needs.

In contrast, the Company's obligation is to ensure sufficient resources to cost-effectively meet MISO's annual resource adequacy requirements, as well as its long-term needs. As discussed in my Direct Testimony, consideration of the Company's load-shape and the supply-role of different generating technologies is important to determining how best to meet long-term needs. Were the Company to ignore those important factors, it would not have information necessary to ensure that its portfolio of long-term resources (for which customers ultimately bear the costs) is consistent with the underlying load that it is designed to serve.

VIII. SITE SELECTION

Q64. DR. WRIGHT OPINES THAT ENO'S SITE SELECTION PROCESS WAS UNREASONABLE BECAUSE IT CONSIDERED ONLY PATERSON AND MICHOUD.[97] DO YOU AGREE WITH HER ASSESSMENT?

A. No. First, I have previously discussed the local considerations that led ENO to evaluate potential locations within Orleans Parish, including the importance of local generation to restoring service after a major storm.[98] Furthermore, in Resolution R-15-524, the Council directed ENO to "use reasonable diligent efforts" to develop a peaking resource "within the City of New Orleans."[99] Consistent with that guidance, ENO evaluated the Paterson and Michoud sites, both of which are located within the City and were once the site of significant sources of generating capacity owned by the Company, and considered factors relating to fuel supply, transmission, existing infrastructure, site suitability, and environmental regulations.[100] It is important to point out, however, that this language from the Council in Resolution R-15-524 does not constitute approval of any unit in any location.

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97 Wright Direct at 12.

98 Cureington Direct at 22–25 (describing the benefits of local generating capacity). Additionally, previous studies of the best site for new generation for ENO were not limited to the Michoud and Paterson sites.

99 New Orleans City Council Resolution R-15-524, at 12.

100 Cureington Direct at 41.

Q65. DID MICHOUD HAVE ANY ADVANTAGES AS A POTENTIAL SITE FOR NOPS?

A. Yes. As I discussed in my Direct Testimony, Michoud has several advantages relating to utility infrastructure.[101] Michoud is located in close proximity to three major gas pipelines, and it has existing office building infrastructure as well as available bays in the high-voltage switchyard for interconnection to the transmission system.[102] In addition, the Michoud substation is strongly interconnected to the Company's service area and the load pocket more broadly, via multiple lines at both 230 kV and 115 kV voltages, which enables a resource at the Michoud site to provide more support to local reliability.[103] In other words, the Company determined that a new unit at Michoud would have more positive effects on transmission reliability in the DSG load pocket than other locations, including Paterson.

Q66. DR. WRIGHT ADDITIONALLY CONTENDS THAT ENO DID NOT CONSIDER RISKS AND ADVERSE IMPACTS TO NEARBY RESIDENTIAL NEIGHBORHOODS WHEN IT SELECTED THE MICHOUD SITE FOR NOPS.[104] HOW DO YOU RESPOND TO THAT CONTENTION?

A. Dr. Wright's contention seems to disregard the knowledge that ENO had about the Michoud site from owning and operating a power plant there for decades. Furthermore, ENO's evaluation has shown that NOPS will not have significant

[101] *See* Cureington Direct at 41–42.
[102] *Id.* at 42.
[103] *Id.*
[104] Wright Direct. at 12.

adverse impacts and will meet all federal and state environmental permitting requirements. Company witness Bliss Higgins notes in her Rebuttal Testimony that information from the Environmental Protection Agency and U.S. Census Bureau indicates that no people live within one mile of the center of the Michoud site.

IX. PUBLIC PARTICIPATION IN THE CONSIDERATION OF NOPS

Q67. DR. WRIGHT CLAIMS IN HER DIRECT TESTIMONY THAT ENO'S PROCESS FOR PLANNING NOPS WAS FLAWED AND BLOCKED PUBLIC INPUT. DO YOU AGREE WITH THAT ASSESSMENT?

A. No. ENO's integrated resource planning process and its specific proposal to construct NOPS have provided multiple opportunities for meaningful public participation. As a regulated utility, ENO's planning processes are subject to far more public scrutiny than many other industrial or commercial entities. And the Council, as ENO's retail regulator, has established a collaborative approach to long-term resource planning that provides the citizens of New Orleans, through their elected representatives, substantial advance information about ENO's plans to meet its customers' power needs. The potential need to develop new, in-region electric generation was identified within that collaborative process, which culminated in ENO's 2015 IRP, the final version of which was filed with the Council on February 1, 2016. Contrary to Dr. Wright's criticisms of that process, the Council and ENO provided multiple opportunities for meaningful public involvement.

In reviewing Dr. Wright's criticisms, it is important to bear in mind that ENO's 2015 IRP report did not formally propose the construction of NOPS. The report, instead, identified resource needs, and ENO later filed with the Council on June 20, 2016, its application for approval to construct NOPS in order to address the identified needs. Although Dr. Wright appears to be aware of these facts, (she states that the siting of NOPS is not mentioned in ENO's 2015 IRP),[105] she goes on to criticize the opportunities for public and stakeholder participation in the IRP process as though NOPS had been formally proposed. In fact, it had not been, and even a brief review of the opportunities for public involvement both before and after ENO finalized its 2015 IRP demonstrates that ENO's actions in no way "resulted in blocking public input."[106]

Q68. PLEASE DISCUSS HOW THE 2015 IRP PROCESS ALLOWED FOR MEANINGFUL PUBLIC INVOLVEMENT.

A. As I noted above, NOPS has been proposed to meet a need for new generation that was identified in ENO's 2015 IRP.[107] New Orleans City Council Resolution R-14-224, approved unanimously on June 5, 2014, established four "milestones" for ENO to meet leading up to the filing of the final 2015 IRP Report.[108] The first milestone discussed DSM potential study inputs; the second discussed DSM potential study results, as well as other assumptions and inputs that would be used in modeling the IRP; the third discussed IRP modeling results; and the fourth discussed the draft IRP

[105] *See* Wright Direct at 12.
[106] *See id.*
[107] *See* Entergy New Orleans, Inc., 2015 Integrated Resource Plan, at 75 (2016).
[108] New Orleans City Council Resolution R-14-224, at 16.

report.[109] The Council required several items and occurrences at each milestone to facilitate public participation and to allow for public comments to be considered in the planning process: "(a) a report from ENO to the Intervenors,[110] Advisors, the public, and the Council; (b) a technical conference; (c) a question-and-answer period where all parties and members of the public may ask questions over ENO's website with the answers posted publicly by ENO; (d) an opportunity for Intervenors to file comments on ENO's report; and (e) input and feedback from the Council."[111]

To facilitate the technical conferences and to encourage public participation, ENO issued a Public Notice thirty days before each meeting[112] and made the materials used during the meetings available to the public via the ENO IRP website.[113] A comment period followed the technical conferences, during which ENO received and answered questions regarding the IRP.[114]

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[109] *Id.*

[110] The Council later took specific steps to allow for participation by additional Intervenors. New Orleans City Council Resolution R-14-364, adopted on September 4, 2014, provided a twenty-day period for additional individuals or entities to intervene. Existing Intervenors the Alliance for Affordable Energy, Jacobs Technology, Inc., the Folger Coffee Company, U.S. Gypsum, and the Sierra Club were allowed to continue as Intervenors. The Resolution also allowed the intervention of the Gulf States Renewable Energy Industries Association ("GSREIA"), Green Coast Enterprises, and the Southeast Energy Efficiency Alliance. *See* R-14-364, at 8. Additional intervenors include Air Products and Chemicals, Inc., the Greater New Orleans Housing Alliance, Posigen Solar Solutions, South Coast Solar, and Building Science Innovators, LLC. *See* New Orleans City Council Resolution R-16-104, at 7.

[111] New Orleans City Council Resolution R-14-224, at 16. Although I provide a summary in my testimony here, I have previously provided the Council with a detailed description of how the company addressed the public participation components of R-14-224. *See* Exhibit 1 Affidavit of Seth Edward Cureington, to ENO's Response to Rule to Show Cause, Docket No. UD-16-01.

[112] *See* Exhibits SEC-1, SEC-4, SEC-6, SEC-9, SEC-14, and SEC-16, attached to Exhibit 1, Affidavit of Seth Edward Cureington to ENO's Response to Rule to Show Cause, Docket No. UD-16-01.

[113] *See* Entergy New Orleans, Inc. Integrated Resource Plan, Entergy New Orleans, Inc., http://www.entergy-neworleans.com/IRP/.

[114] Exhibit 1, Affidavit of Seth Edward Cureington to ENO's Response to Rule to Show Cause, Docket No. UD-16-01, at 9.

The milestone technical conferences were all held at the Lindy C. Boggs International Conference Center at the University of New Orleans. Dr. Wright's Direct Testimony takes issue with the fact that none of those conferences took place in New Orleans East, where ENO plans to construct NOPS. However, the IRP affects the power plan for the entire city of New Orleans. As such, it was not improper to hold the meetings relating to the IRP at one central location that was accessible from all points of the city, including New Orleans East. ENO specifically explained that it held the meetings at this location so as "to provide a central, accessible, consistent and neutral meeting location."[115] Furthermore, as I discuss later in my testimony, ENO hosted a Public Technical Conference in New Orleans East regarding the Final 2015 IRP in May 2016,[116] and, once it filed its initial application for approval to construct NOPS, ENO participated in several NOPS-specific meetings in New Orleans East.[117]

In addition to holding the four technical conferences required by Resolution R-14-224, ENO hosted, at the direction of the Council, a first Interim Milestone Technical Conference between Milestones 1 and 2.[118] And ENO voluntarily held a Second Interim Milestone Technical Conference between Milestones 3 and 4 in order

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[115] Entergy New Orleans, Inc., 2015 Integrated Resource Plan, at 35.

[116] http://www.entergy-neworleans.com/content/IRP/ENO_2015_IRP-Public_Notice.pdf.

[117] *See* Entergy New Orleans Hosts Public Information Sessions on Proposed New Orleans Power Station in November, Entergy New Orleans, Inc. (Nov. 10, 2016), http://www.entergynewsroom.com/latest-news/entergy-new-orleans-hosts-public-information-sessions-proposed-new-orleans-power-station-november/; and Entergy New Orleans Hosts Public Information Sessions on Proposed New Orleans Power Station in December, Entergy New Orleans, Inc. (Nov. 15, 2016), http://www.entergynewsroom.com/latest-news/entergy-new-orleans-hosts-public-information-sessions-proposed-new-orleans-power-station-december/.

[118] Exhibit 1, Affidavit of Seth Edward Cureington to ENO's Response to Rule to Show Cause, Docket No. UD-16-01, at 2–9.

to provide stakeholders and the Council's Advisors additional opportunity to review portfolio evaluation results before ENO released its Draft IRP and proceeded to the Milestone 4 Technical Conference.[119] ENO presented its Draft IRP at the Milestone 4 Technical Conference on June 30, 2015.

After Milestone 4, ENO received extensive criticism of information, methods, and assumptions that had been presented during earlier milestones.[120] ENO explained its view that much of that criticism concerned inputs and assumptions used in the modeling for the 2015 IRP and should have been raised earlier, in accordance with the Council's timeline for the IRP process, to allow for the feedback to be incorporated in the modeling.[121] But, after receiving recommendations from the Council's Advisors, ENO worked on an action plan for finalizing the IRP and incorporating as much of the stakeholder input as possible.[122] After filing its action plan, ENO convened a conference call to discuss it and to provide transparency around the planned steps for finalizing the IRP.[123] Furthermore, in response to feedback received during that call, ENO revised its action plan and committed to revising certain assumptions and inputs and to creating and modeling a Stakeholder Input Case in the IRP, all in an effort "to incorporate actionable Stakeholder feedback."[124] Using this newly developed set of assumptions, ENO ran additional simulations and discussed the results of the Stakeholder Input Case throughout the

[119] *Id.* at 9.
[120] *Id.* at 9–10.
[121] *Id.*
[122] *Id.* at 10–11.
[123] *Id.* at 11.
[124] *Id.* at 11–12.

Final 2015 IRP and in a supplement to the IRP.[125] ENO's efforts to incorporate stakeholder feedback received even after it had done extensive modeling and satisfied earlier milestones set by the Council show that it was responsive to concerns voiced during the IRP process. Furthermore, the foregoing summary of that process demonstrates that Dr. Wright's charge that ENO "unilaterally develop[ed] the Integrated Resource Plan without meaningful public input"[126] is incorrect and unfair.

Q69. WERE THERE OPPORTUNITIES FOR PUBLIC REVIEW AND COMMENT ON THE FINAL 2015 IRP?

A. Yes. After ENO filed the Final 2015 IRP on February 1, 2016, the Council passed Resolution R-16-104, on April 7, 2016, determining that, "notwithstanding the extensive stakeholder process already undertaken," it wanted to "solicit public comments on ENO's Final 2015 Integrated Resource Plan to aid in its consideration for approval…."[127] The Council directed ENO to hold a technical conference the week of May 9, 2016, with a 15-day public comment period to follow.[128] The Council additionally directed its Advisors to convene a Community Hearing in the

125 *See* Entergy New Orleans, Inc., 2015 Integrated Resource Plan, at 12, 35–40, 49–51, 64–72, 79, and 81–82; *see also* Supplement 11: Stakeholder Input Case, Entergy New Orleans, Inc., http://www.entergy-neworleans.com/content/irp/Supplement_10_1-DSM_Stakeholder_Input_Case_Assumptions.pdf, at 27–41.

126 Wright Direct at 9.

127 New Orleans City Council Resolution R-16-104, at 6.

128 *Id.* at 7–8.

Council Chambers on June 15, 2016.[129] Intervenors were given an almost two-month period to submit comments regarding the IRP.[130]

As Dr. Wright acknowledges in her testimony, ENO held a Public Technical Conference on May 12, 2016, in accordance with the Council's directive, and ENO chose to conduct the meeting in New Orleans East.[131] Dr. Wright includes the notice as Exhibit 3 to her testimony and contends, among other things, that the notice did not give full details about the IRP. But the IRP addresses issues and analyses that are complex, and providing a complete understanding of the plan is not a reasonable expectation of the meeting notice. The notice complied with the Council's directive that ENO issue "sufficient notice to the public to allow for all interested to attend the technical conference."[132] The notice also provided an email address and telephone number for interested members of the public to address questions to ENO and included the website address for ENO's IRP. At that address, ENO posted a full copy of the Final 2015 IRP Report. In connection with the Public Technical Conference, ENO also provided a 35-page presentation that included information about (1) the development, objectives, stages, modeling, and analyses of the 2015 IRP; (2) ENO's resource needs; (3) identification and assessment of DSM options; (4) identification and assessment of supply alternatives, including solar and other renewable options; (5) the composition and relative costs of supply portfolios considered in the IRP

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129 *Id.* at 8.

130 *Id.*

131 *See* Wright Direct at 6; *see also* http://www.entergy-neworleans.com/content/IRP/ENO_2015_IRP-Public_Notice.pdf.

132 New Orleans City Council Resolution R-16-104 at 7.

analysis; (6) stakeholder input received, ENO's actions to address that input, and the results of additional analysis done for the Stakeholder Input Case; and (7) the components of the Preferred Portfolio identified through the IRP process and ENO's action plan. These materials and efforts meet any reasonable standard of providing the public with information about the IRP and facilitating the review process directed by the Council.

Q70. DR. WRIGHT STATES IN HER DIRECT TESTIMONY THAT "STRONG PUBLIC OPPOSITION" WAS VOICED CONCERNING NOPS AT THE JUNE 2016 COMMUNITY HEARING ON ENO'S 2015 IRP.[133] HOW DO YOU RESPOND TO THAT TESTIMONY?

A. Dr. Wright's testimony obscures the purpose of the June 15, 2016 Community Hearing directed by the Council. Although ENO's action plan to implement the needs identified in the 2015 IRP included the addition of an in-region "peaking" resource by 2019, ENO had not yet filed its application to construct NOPS at the time of the Community Hearing, and the purpose of that hearing was to allow the public to express its views on the Final 2015 IRP. Before the hearing, the Alliance for Affordable Energy sent out communications[134] that relayed—whether intentionally or not—a sense that ENO would be presenting a plan to construct a new unit in New Orleans East at the June 15, 2016 hearing. Those communications and related

[133] Wright Direct at 9.

[134] *See* ENO's Response to Rule to Show Cause, Docket No. UD-16-01, at 27–30. *See also* http://i.szoter.com/f4fa1442eb86412a; http://i.szoter.com/e19bebe15648e66b; http://i.szoter.com/5574b479c88b2fc4; http://all4energy.org/2016/06/new-natural-gas-plant-new-orleans-east/; and Exhibits 11–13 to ENO's Response to Rule to Show Cause, Docket No. UD-16-01.

misunderstanding about what ENO intended to address at the hearing could well explain some of the residents' comments about public outreach that Dr. Wright notes in her testimony. Although there certainly is an important relationship between ENO's 2015 IRP and its proposal to construct NOPS, the June 15, 2016 Community Hearing was not intended to address the sort of NOPS-specific issues that Dr. Wright raises in her testimony.

Q71. DID ENO ENGAGE IN MEANINGFUL COMMUNITY OUTREACH AFTER THE JUNE 2016 COMMUNITY HEARING IN CONNECTION WITH ITS INITIAL APPLICATION TO CONSTRUCT NOPS?

A. Yes. After filing its initial application, ENO participated in multiple meetings with community groups, neighborhood associations, and other civic organizations to discuss issues surrounding NOPS.[135] The Council, moreover, passed Resolution R-16-506 on November 3, 2016, to set a procedural schedule for the consideration of ENO's application for approval to construct NOPS. The Council noted expressly in that resolution its intention to afford meaningful public involvement in that process: "[T]he Council intends to provide the residents of the City of New Orleans with an open and transparent process that will allow for multiple opportunities for the public to communicate its views to ENO and the Council as they relate to the construction of the proposed project…."[136] Consistent with that intention, the Council (1) ordered ENO to make a supplemental filing in November 2016 to address groundwater

[135] Entergy New Orleans, Inc.'s Response to Rule to Show Cause, Docket No. UD-16-01, at 31.

[136] New Orleans City Council Resolution R-16-506, at 8.

withdrawal and subsidence at the Michoud site and potential air-quality effects of NOPS; (2) provided an opportunity for Intervenors to file testimony; (3) required ENO to conduct at least two public outreach meetings related to NOPS before December 24, 2016; (4) provided for a public hearing in Council Chambers before December 24, 2016, "for the purpose of receiving additional public comment related to the project"; and (5) created a mechanism for interested persons to receive email notices of any public meetings or public hearings concerning the NOPS application.[137]

After the Council passed Resolution R-16-506, ENO conducted the following Community Information Sessions in New Orleans East to share information about NOPS: November 10, 2016 (Einstein Charter School Auditorium); November 14, 2016 (New Orleans East Public Library General Meeting Room); December 13, 2016 (Epiphany Baptist Church Sanctuary); and December 14, 2016 (Apostolic Outreach Center Sanctuary).[138] ENO prepared handouts for those meetings in English, Spanish, and Vietnamese.[139] Those meetings and a December 12, 2016 public hearing in Council Chambers that was conducted in accordance with the Council's resolution provided opportunities for the public to raise concerns about NOPS. Dr. Wright's suggestion that public input has been blocked is simply not correct.

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[137] *Id.* at 8–11.

[138] *See* http://www.entergynewsroom.com/latest-news/entergy-new-orleans-hosts-public-information-sessions-proposed-new-orleans-power-station-november/ and http://www.entergynewsroom.com/latest-news/entergy-new-orleans-hosts-public-information-sessions-proposed-new-orleans-power-station-december/.

[139] New Orleans Power Station Community Information, Entergy New Orleans, Inc., http://www.entergy-neworleans.com/powertogrow/power_station/community.aspx.

Q72. DR. WRIGHT ASSERTS IN HER SUPPLEMENTAL TESTIMONY THAT ENO'S SUPPLEMENTAL APPLICATION IN THIS DOCKET DOES NOT ADDRESS OR REMEDY "THE WOEFULLY INADEQUATE PROCESS FOR PUBLIC INPUT THAT EXCLUDED THE PARTICIPATION OF PEOPLE WHO WOULD BE MOST IMPACTED BY THE PROPOSED POWER PLANT."[140] HOW DO YOU RESPOND TO THAT TESTIMONY?

A. Dr. Wright does not support her bare assertion that ENO has a "woefully inadequate process for public input" or that ENO has excluded the participation of anybody with regard to NOPS. As I discussed above, ENO received extensive public input throughout the 2015 IRP process and since it proposed NOPS. ENO employees, including the Company's President and CEO, have attended numerous community meetings concerning NOPS, and the Company's July 2017 Supplemental Application reflected and responded to various issues that have been addressed in those meetings. Indeed, the Supplemental Application's Alternative Peaker proposal, which addresses both the need for reliable generation within the City and concerns raised about the size of the proposed CT, demonstrates that ENO has received and responded to stakeholder input in a reasonable, productive manner.

ENO's community outreach efforts have continued since the filing of the Supplemental Application. In setting the procedural schedule for consideration of the Supplemental Application, the Council set forth its intention "to provide the residents of the City of New Orleans with an open and transparent process that will allow for

140 Wright Supplemental Testimony, October 2017, at 2.

multiple opportunities for the public to communicate its views to ENO and the Council as they relate to either of the proposed projects."[141] Consistent with that intention, the Council instructed ENO to "conduct a minimum of five public outreach meetings, one in each Council district, for the purpose of sharing information with, and answering questions from, the public related to the proposed projects."[142] ENO went above and beyond the number of meetings prescribed by the Council and held nine public meetings regarding the NOPS proposals, four of which were held in New Orleans East.[143] Additionally, all notices of these meetings, as well as the handouts provided at the meetings, were available in English, Spanish, and Vietnamese in order to facilitate participation from all concerned residents of New Orleans.[144] Furthermore, the Council held a public meeting in its chambers on October 16, 2017,[145] that was well-attended and featured a significant amount of community support for NOPS.

In summary, ENO has held at least **<u>21</u>** public meetings regarding NOPS, many of which have been held in New Orleans East. And that number does not include the several public meetings concerning NOPS that the Council has held in its chambers. Rather than being "woefully inadequate," it is clear that ENO has made extensive and reasonable efforts to include and inform the public about NOPS.

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[141] City Council Resolution R-17-426, at 14–15.

[142] *Id.* at 17.

[143] *See* New Orleans Power Station Public Notices, http://www.entergyneworleans.com/powertogrow/power_station/NOPS_Community_Meetings.pdf; and http://entergyneworleans.com/powertogrow/power_station/Entergy_NOPS_Sept_27_meeting.pdf.

[144] *See* New Orleans Power Station Community Information, http://entergyneworleans.com/powertogrow/power_station/community.aspx.

[145] *See* Public Notice of Public Hearing, http://nolacitycouncil.com/docs/notices/10-16%20PN.pdf.

X. CONCLUSION

Q73. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SETH CUREINGTON**, who after being duly sworn by me, did depose and say:

That the above and 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.

Seth Cureington

Seth Cureington

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 17th DAY OF NOVEMBER, 2017

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

2016 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC ECONOMICS

**Independent Market Monitor
for the Midcontinent ISO**

June 2017

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Guide to Acronyms

AMP	Automated Mitigation Procedures
ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Markets
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CDD	Cooling Degree Days
CMC	Constraint Management Charge
CONE	Cost of New Entry
CRA	Competitive Retail Area
CROW	Control Room Operating Window
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CTS	Coordinated Transaction Scheduling
DAMAP	Day-Ahead Margin Assurance Payment
DDC	Day-Ahead Deviation and Headroom Charge
DIR	Dispatchable Intermittent Resource
DR	Demand Response
DRR	Demand Response Resource
ECF	Excess Congestion Fund
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFE	Firm Flow Entitlement
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
GWh	Gigawatt-hour
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
IESO	Ontario Independent Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JCM	Joint and Common Market
JOA	Joint Operating Agreement
kWh	Kilowatt-hour
LAC	Look-Ahead Commitment

LAD	Look-Ahead Dispatch
LMP	Locational Marginal Price
LSE	Load-Serving Entity
M2M	Market-to-Market
MATS	Mercury and Air Toxics Standards
MCP	Marginal Clearing Price
MISO	Midcontinent Independent Transmission System Operator
MMBtu	Million British thermal units, a measure of energy content
MSC	MISO Market Subcommittee
MTLF	Mid-Term Load Forecast
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NDL	Notification Deadline
NERC	North American Electric Reliability Corporation
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
ORCA	Operations Reliability Coordination Agreement
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection, Inc.
PRA	Planning Resource Auction
PVMWP	Price Volatility Make Whole Payment
PY	Planning Year
RAC	Resource Adequacy Construct
RCF	Reciprocal Coordinated Flowgate
RDI	Residual Demand Index
RGD	Regional Generation Dispatcher
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
SMP	System Marginal Price
SOM	State of the Market
SPP	Southwest Power Pool
SRPBC	Sub Regional Power Balance Constraint
SSR	System Support Resource
STLF	Short-Term Load Forecast
TCDC	Transmission Constraint Demand Curve
TLR	Transmission Line Loading Relief
VCA	Voluntary Capacity Auction
VLR	Voltage and Local Reliability
WUMS	Wisconsin-Upper Michigan System

EXECUTIVE SUMMARY

As the Independent Market Monitor (IMM) for the Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity includes monitoring for attempts to exercise market power or manipulate the markets, identifying market design flaws or inefficiencies, and recommending improvements to the market design and operating procedures. This Executive Summary to the *2016 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

MISO operates competitive wholesale electricity markets in the Midcontinent region that encompasses a geographic area from Montana east to Michigan and south to Louisiana. The MISO South region shown to the right in blue was integrated in December 2013.

MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, its ancillary services market in 2009, and its most recent capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably and at the lowest cost.

Additionally, the MISO markets establish prices that reflect the marginal value of energy at each location on the network (i.e., locational marginal prices or LMPs). These prices facilitate efficient actions by participants in the short term (e.g., to make resources available and to schedule imports and exports) and support long-term decisions (e.g., investment, retirement, and maintenance). The remainder of this Executive Summary provides an overview of market outcomes, a discussion of key market issues, and a list of recommended improvements.

Market Outcomes and Competitive Performance in 2016

The MISO energy and ancillary services markets generally performed competitively in 2016. The most notable factor affecting market outcomes in 2016 was the continuing decline in fuel prices through the first half of the year, with natural gas prices falling to their lowest levels since the commencement of the MISO markets in 2005. The 10 percent decrease in natural gas prices from 2015 and declines in other fuel prices led to a 3 percent reduction in energy prices throughout MISO, which averaged $26.56 per MWh in 2016.

Energy prices did not fall as much as fuel prices because relatively hot conditions during the summer in 2016 resulted in higher loads and prices in these months. Nonetheless, the MISO markets continue to exhibit a consistent overall relationship between energy and natural gas prices. This is expected in a well-functioning, competitive market. Natural gas-fired resources are frequently the marginal source of supply, and fuel costs constitute the vast majority of most resources' marginal costs.

In addition to this overall correlation, we evaluate the competitive performance of the MISO markets by assessing the conduct of its suppliers, which was broadly consistent with expectations for a workably competitive market. This is indicated by the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. Our analysis revealed the price-cost mark-up 0.5 percent, or effectively zero, in 2016. This indicates that the MISO markets were highly competitive in 2016.

- The "output gap" is a measure of potential economic withholding. It remained unchanged from 2015, averaging 0.11 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

Although system-wide energy prices fell slightly, prices often varied substantially throughout MISO, reflecting congestion on the MISO transmission network. The value of real-time congestion increased by four percent to $1.4 billion, partly due to hot conditions and storms during the summer and high levels of outages in the spring and fall. We recommend a number of improvements in this Report to lower the cost of managing congestion on MISO's system.

MISO implemented several market design changes in 2016 that should improve the efficiency and competitiveness of the MISO markets.

- On February 1, MISO implemented a settlement agreement with its neighbors and created the Regional Dispatch Transfer (RDT) constraint that allows 3,000 MW of flow in the North-to-South direction and 2,500 MW of flow in the South-to-North direction.
  - This allowed much higher interregional flows from the prior 1,000 MW constraint.
  - Net interregional flows between the MISO South and MISO Midwest regions were predominantly in the South-to-North direction early in the year.
  - The flows reversed to be prodominantly in the North-to-South direction in the summer and in the fall because of high levels of generation outages in the South.
- On May 1, MISO implemented the ramp product, which contributed to low price volatility and slightly lower prices in the real-time market.
- In July, emergency pricing was implemented to ensure that additional supply or demand reductions acquired through emergency actions are priced at appropriate shortage levels.
- In September, the Real-Time Offer Enhancement (RTOE) capability was introduced to allow resources to update offers intra-hour to reflect short-term operating limitations.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

In 2016, MISO lost 6.8 GW of resources to retirement, suspension, or because they were pseudo-tied out of MISO to PJM. MISO added 3.6 GW of resources, but 1.4 GW were renewable resources whose capacity value is relatively low. Based on the capacity market design concerns we discuss in this report, we expect the installed capacity in MISO to continue to fall. In the near-term, however, our assessment indicates that the system's resources should be adequate for the summer of 2017 if the peak conditions are not substantially hotter than normal.

- We estimate a planning reserve margin of 18.9 percent, which exceeds MISO's planning reserve requirement of 15.8 percent.
- Under hotter than normal summer conditions and realistic assumed performance of MISO's demand response (DR) capability, the planning margin would be 10 percent. This margin should be sufficient given typical forced outage rate of 5 to 8 percent.

Long-Term Signals: Net Revenues

Market prices should provide signals that govern participants' long-run investment, retirement, and maintenance decisions. These signals can be measured by the "net revenues" generators receive in excess of their production costs. We evaluate these signals by estimating the net revenues that different types of new resources would have received in 2016, and found:

- Net revenues increased at locations in MISO Central and North compared to last year and decreased in locations in MISO South;
- However, net revenues continue to be substantially less than necessary for new investment to be profitable in any area (i.e., the annual cost of new entry, or "CONE").

Low natural gas prices have led to low energy prices, which have disproportionately affected the net revenues of non-gas-fired resources, most notably nuclear units. This has led some suppliers that own nuclear resources to announce plans to retire their units. Late in 2016, the State of Illinois passed legislation to subsidize two nuclear units to extend their operations for 13 years.

Capacity market design issues described in this report have contributed to understated price signals, which will become an increasing concern as the capacity surplus falls due to retirements and units exporting capacity to PJM. In 2016, approximately three GW of MISO's coal-fired resources retired or pseudo-tied into PJM, largely due to the combined effects of low gas prices, costly retrofits required by environmental regulations, and low capacity prices in MISO. Although most of MISO is vertically integrated, it still has may resources owned by competitive suppliers and loads served by competitive load-serving entities. These participants rely on the economic signals from MISO's markets to guide their long-term decisions. Decisions of regulated suppliers are also informed by these economic signals. Hence, establishing efficient capacity and energy prices remains essential to ensuring resource adequacy in the MISO region.

PRA Results and Design

MISO administers a Planning Resource Auction (PRA) to allow its participants to buy and sell capacity at various locations in MISO to satisfy the capacity requirements established in Module E of the MISO Tariff.[1] The auction includes MISO-wide requirements, local clearing requirements in ten local zones, and models a transfer constraint between MISO South and MISO Midwest regions.

The design issues described below, along with modest changes in supply and demand, have resulted in volatile market outcomes over the past two years:

- In 2016/2017, the auction cleared at $72 per MW-day throughout most of the Midwest subregion and $2.99 per MW-day in MISO South.
- In 2017/2018, decreased capacity requirements and increased assumed transfer capability between subregions contributed to a MISO-wide clearing price of essentially zero ($1.50 per MW-day).

The extremely low clearing price in the most recent auction and the price volatility more broadly is a result of the capacity market design issues we discuss below.

PRA Design Issues

Several PRA design issues continue to undermine the efficiency of the PRA and contributed to the price volatility in MISO's capacity prices in the past few years. The most significant design flaw relates to how the demand for capacity is represented. Demand in the PRA is modeled as a single MISO-wide requirement and single zonal requirements and a deficiency price if the market is short. This effectively establishes a "vertical demand curve" for capacity, which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value and results in inefficient capacity market outcomes. To address this issue, we continue to recommend that MISO adopt a sloped demand curve to reflect the reliability value of resources that are in excess of MISO's minimum clearing requirement.

Understated capacity prices is a particular problem in Competitive Retail Areas (CRAs) where unregulated suppliers rely on the market to retain resources MISO needs to ensure reliability. In 2016, MISO developed a proposal to improve the capacity pricing in CRAs that we did not support. We offered an alternative proposal that would establish prices for CRAs that reflect the marginal reliability value of MISO's unregulated resources. While FERC rejected MISO's proposed solution, we believe FERC would approve an efficient proposal. Hence, we continue to encourage MISO to pursue a reasonable solution to ensure efficient capacity prices, if only for competitive loads and suppliers.

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1 Hereinafter, "Tariff" will refer to MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

In addition to addressing the fundamental design issue related to the modeling of the demand in the PRA, we have recommended a variety of other improvements to the PRA, including:

- Allowing units with Attachment Y retirement requests to participate in the PRA and have the ability to postpone or cancel the retirement if they clear in the auction.
- Transitioning to a seasonal capacity market.
- Improving the modeling of transmission constraints in the PRA.

Transmission Congestion

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources. The costs of these dispatch changes are congestion costs and arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location given the marginal energy costs, network congestion, and losses. Because most market settlements occur through the day-ahead market, most congestion costs are collected in this market.

Congestion Costs in 2016

The value of real-time congestion increased by four percent from last year to $1.4 billion. Congestion levels were highest during the summer months, when real-time congestion rose 35 percent from last summer (to $464 million), which was due to high loads and key generation and transmission outages, particularly in the South. High network flows from wind resources in MISO and PJM contributed to the congestion in the spring and fall. These factors more than offset the reductions in natural gas prices that tend to reduce the costs of managing congestion in MISO, as well as the much lower congestion costs in early 2016 because of mild winter weather.

During 2016, MISO continued to pursue improvements to lower the cost of congestion and improve dispatch efficiency.

- In October 2015, MISO reached a settlement with SPP and other parties to increase the constraint on flows between the MISO South and Midwest subregions from 1,000 MW up to levels ranging from 2,500 MW to 3,000 MW. This increased economic transfers between regions and allowed MISO to capture substantial dispatch savings.
- MISO and the IMM have worked with transmission owners to improve the utilization of the transmission system by obtaining more accurate facility ratings. This included a pilot program with one transmission owner to expand the use of temperature-adjusted, emergency ratings. This program has been successful and we recommend that MISO expand it to include more constraints and other transmission owners.

Although improvements have been made, we are concerned that a significant amount of congestion could have been avoided or managed more efficiently. For example, we found that more than $450 million of the congestion from January 2016 to May 2017 was incurred on constraints in cases where more than one planned outage was scheduled that affected the same constraint. Some of these planned outages were also scheduled when planned transmission outages were occurring. We believe congestion could have been reduce significantly in 2016 if MISO had expanded authority to coordinate planned outages.

Not all of the $1.4 billion in real-time congestion is collected by MISO through its markets, primarily because loop flows caused by others and flow entitlements granted to PJM, SPP and TVA do not pay MISO for use of the network. Hence, day-ahead congestion costs totaled $737 million in 2016, down two percent from last year. These congestion costs are used to fund MISO's FTRs.

FTR Shortalls and Balancing Congestion Shorfalls

FTRs represent the economic property rights associated with the transmission system. FTRs are acquired in MISO-administered auctions and serve as a hedge against day-ahead congestion costs. If the FTRs issued by MISO are physically feasible (do not imply more flows over the network than the limits in the day-ahead market), then MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs – to pay them 100 percent of the FTR entitlement – which was the case in 2016. FTR shortfalls arise when insufficient day-ahead congestion is collected to fully fund the FTRs. Under-funding FTRs degrades the value of the FTRs. Ultimately, this harms transmission customers that receive reduced revenues from the sale of the FTRs. Therefore, the full funding in 2016 is a good outcome and MISO should ultimately consider guaranteeing full funding of FTRs.

Balancing congestion shortfalls (negative balancing congestion revenue) occurs when the transmission capability available in the real-time market is less than the capability scheduled in the day-ahead market. In other words, the network was over-scheduled in the day-ahead market, which tends to be caused by real-time transmission outages, derates, or loop flows that were not anticipated in the day-ahead market. Balancing shortfalls are uplifted to MISO's customers. Balancing congestion costs increased 47 percent in 2016 to nearly $41 million. These levels of balancing congestion costs indicate that consistency between the day-ahead and real-time market models and assumptions could likely be improved.

Market-to-Market Coordination and External Congestion

MISO incurs a substantial amount of congestion on external constraints located in PJM or SPP, which are coordinated through the market-to-market processes. Likewise, there are many MISO constraints that are coordinated with PJM and SPP because generation in these areas affect the flows on these constraints. The number of MISO constraints that need to be coordinated with PJM are growing rapidly as PJM has taken dispatch control of increasing numbers of MISO generators via pseudo-ties. Over the past year, more than one-hundred new market-to-market constraints in MISO have been defined because of the MISO units that have been pseudo-tied to PJM.

Congestion on MISO's market-to-market constraints grew 26 percent in 2016 to $377 million, which is more than one fourth of all congestion in MISO. Because there are so many MISO constraints that are substantially affected by generators in SPP and PJM, it is increasingly important that the market-to-market coordination operate as effectively as possible. To that end, we evaluated whether the RTOs are defining new market-to-market constraints when warranted and activating existing market-to-market constraints in a timely manner. We found $238 million in congestion on MISO constraints that: a) likely should have been defined as market-to-market constraints ($192 million), b) were delayed in being defined ($41 million), or c) were delayed in being activated after they were defined ($5 million). These results indicate that the RTOs should improve the automation of their testing process to ensure that constraints are appropriately tested and activated to coordinate congestion efficiently.

Lastly, some of the most costly market-to-market constraints are constraints that are dominated by generation in the non-monitoring RTO area (e.g., SPP or PJM constraints dominated by MISO or vice versa). This situations have sometimes caused the RTOs to abandon economic coordination and seek other means to manage the constraint. In these cases, substantial savings can be achieved by transferring the monitoring responsibility for the constraint to the non-monitoring RTO. Hence, we recommend MISO continue working with SPP and PJM to implement a procedure to transfer the monitoring responsibility when appropriate.

Day-Ahead Market Performance

The day-ahead market is critically important because it coordinates most resource commitments and is the basis for almost all energy and congestion settlements with participants. Day-ahead market performance can be judged by the extent to which day-ahead prices converge with real-time prices, because this will result in the resource commitments needed to efficiently satisfy the system's real-time operational needs. In 2016:

- The difference between day-ahead and real-time prices was 0.4 percent, after accounting for day-ahead and real-time uplift charges, which is good convergence overall.

- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence, particularly in MISO South.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared virtual transactions increased by more than 50 percent in 2016, resulting in lower overall profitability of virtual trades. Most of this virtual trading is by financial participants and the report shows that roughly 60 percent of this virtual trading improved price convergence and economic efficiency in the day-ahead market. Hence, virtual trading continues to be a vital component of the MISO's market. The improvements MISO has made in the allocation of RSG costs have resulted in more active virtual trading and a more liquid day-ahead market than any other market we monitor.

Price convergence was worst at congested locations in 2016, as in prior years. Price-insensitive transactions continued to frequently be placed to establish an energy-neutral (balanced) positions (offsetting virtual supply and demand at different locations) to arbitrage congestion-related price differences. These positions are valuable in improving the convergence of congestion between the day-ahead and real-time markets but would be more effective if they could be submitted price-sensitively through a virtual spread product. Participants today must submit these transactions with prices that compel both sides of the position to clear, which increases the risk of the positions. Accordingly, we continue to recommend MISO develop a virtual spread product that may be submitted price sensitively, which should improve the convergence of day-ahead and real-time congestion patterns.

Real-Time Market Performance and Uplift

The performance of the real-time market is very important because it governs the dispatch of MISO's resources. The real-time market sends economic signals that facilitate scheduling in the day-ahead market and longer-term decisions. Additionally, efficient price signals during shortages and tight operating conditions can reduce the reliance on revenue from the capacity market to maintain resource adequacy. Real-time prices were competitive in 2016, as indicated above, falling 3 percent relative to 2015.

Real-Time Price Formation

In March 2015, MISO implemented the Extended Locational Marginal Pricing (ELMP) algorithm. ELMP is intended to improve price formation in the real-time energy and ancillary services markets by allowing prices to better reflect the true marginal costs of supplying the system at each location. ELMP reforms pricing by allowing:

- Online, inflexible fast-start resources to set the LMP when they are economic.[2] These are online "Fast-Start Resources" and demand response resources.
- Offline fast-start resources to be eligible to set prices during transmission or energy shortage conditions.

MISO's initial ELMP rules permitted only five percent of the online peaking resources to set prices. In May 2017, MISO implemented Phase 2 of ELMP that would have allowed 16 percent of peaking resources dispatched in 2016 to set prices. While this is an improvement, the vast majority of the peaking resources utilized by MISO are still ineligible to set real-time prices. Therefore, we recommend that ELMP be extended to most of the remaining peaking resources, which would have reduced the $17 million in RSG payments made to these units.

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2 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff term as: a "Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less…."

It is efficient for offline resources to set the price only when a) they are feasible (can be started quickly to address the shortage), and b) they are economic for addressing the shortage. Our evaluation revealed that only seven percent of the offline resources that set prices under ELMP appeared to be both feasible and economic. Accordingly, we conclude that ELMP's offline pricing is inefficiently changing real-time prices during shortage conditions and recommend that MISO disable the offline pricing logic.

Real-Time Generator Performance

Our greatest concern regarding the real-time market is the poor performance of some of the generators in following MISO's dispatch instructions. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) in 2016 averaged 158 MW and averaged almost 600 MW in the worst 10 percent of the intervals. Although this is an improvement over 2015, it continues to raise substantial economic and reliability concerns because these deviations were often not perceived by MISO's operators.

To address these concerns, we have proposed better uninstructed deviation thresholds and modifications in the DAMAP formulas to greatly improve incentives for generators to follow dispatch signals. We have also recommended better tools for operators to identify poor generator performance and State-Estimator model errors that are contributing to inefficient dispatch. These changes will improve generators' performance and would have lowered DAMAP by one third (more than $12 million) in 2016.

Wind Overforecasting

We determined that average deviations by wind units are larger than any other class of resource. These deviations occur because a number of wind units tend to substantially overforecast their output. The forecast is used by MISO to establish wind units' dispatch maximum, and because their offer prices are low, also usually their dispatch level. These results raise concerns because they undermine the efficiency of MISO dispatch and may lead to unjustified payments to the wind resources. The wind deviations contributed to increased congestion and under-utilization of the transmission system, supply and demand imbalances, and caused non-wind resources to be dispatched at inefficient output levels.

In evaluating the causes for the forecast errors, we found that:

- Wind resources in MISO have a strong incentive to overforecast their output because the settlements for Excessive Energy (incurred when they underforecast) are far more punitive than the Deficient Energy settlements (incurred when they overforecast); and
- Day-Ahead Margin Assurance Payments (DAMAP) settlement rules can allow wind resources to earn more revenue by deliberately overforecasting their output than by forecasting accurately.

Hence, we are recommending a number of changes to the deviation thresholds, excessive and deficient energy settlement rules, and DAMAP rules to provide incentives for wind resources to forecast their output accurately. We are also recommending that MISO validate the forecasts in real time and address sustained errors when it produces its real-time dispatch.

Real-Time Settlements

MISO's real-time market produces new dispatch instructions and prices every five minutes, but settlements are based on hourly-average prices. This inconsistency can create incentives for suppliers to be inflexible. For this reason, MISO instituted Price Volatility Make-Whole Payments (PVMWP) to ensure that suppliers are not harmed when they respond to MISO's five-minute dispatch instructions. Total PVMWPs, the vast majority of which are DAMAP, rose 1.6 percent in 2016 as price volatility at the resources' locations increased by two percent.

PVMWPs will be substantially reduced and generators will have stronger incentives to be flexible and follow MISO's dispatch instructions when MISO implements five-minute settlements for generators in early 2018. We have recommended this important change for a number of years because better generator performance will produce production cost savings for the system and improve reliability. FERC endorsed this by issuing a rulemaking that requires RTOs to settle with generators in the same time increments as their dispatch (i.e., five-minute settlements for MISO).[3]

In addition to this change, our evaluation in this report indicates that roughly one-third of MISO's DAMAP is paid to units because they are not following MISO's dispatch instructions or to wind resources that are not forecasting their output accurately. The wind resources are only eligible for these DAMAP revenues because of the flaw in MISO's tariff that we recommend they correct as quickly as possible. To address the broader issue, we recommend that MISO reform its DAMAP and RTORSP formulas to only make payments to resources that are performing reasonably well in following MISO's dispatch instructions. This will not only lower the costs of these payments, but improve the incentives for generators to perform well.

Uplift (RSG) Costs

Revenue Sufficiency Guarantee (RSG) payments are made in both the day-ahead and real-time markets to ensure suppliers' offered costs are recovered when a unit is dispatched.

- Real-time RSG payments fell 1.6 percent to $5.2 million per month.
- Day-ahead RSG costs fell by almost 50 percent to $3.4 million per month. Slightly more than half of these payments. Almost 60 percent of the day-ahead RSG costs were associated with Voltage and Local Reliablity (VLR) commitments in MISO South.

3 FERC Order 825, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, issued June 16, 2016.

Most of these RSG reductions were due to lower fuel prices and improvements in the procedures for satisfying the VLR needs in MISO South. The RSG associated with VLR requirements in MISO South is attributable to reliability needs that are not reflected in the market. We have recommended that MISO develop a new operating reserve product that would reflect these needs and establish prices that incent participants to provide it in both the short-term (by committing of resources in the area) and long-term (by building new resources in the area).

Pseudo-Ties to PJM and Real-Time Dispatch Concerns

Because MISO's market does not establish efficient capacity prices, suppliers with uncommitted capacity have been exporting their capacity to PJM in increasing quantities. This has raised substantial operational concerns because PJM requires these units to be "pseudo-tied" to PJM. Twelve resources in MISO pseudo-tied into PJM in 2016. Because they affect power flows over numerous constraints on MISO's network, losing dispatch control of the units undermines MISO's dispatch and its ability to manage congestion on its network efficiently. Our analysis in this report shows that congestion on the constraints affected by these units have increased by 152 percent on a monthly average basis from before the pseudo-ties were implemented. Our analysis in this Report also shows that the dispatch of pseudo-tie resources has been much less efficient than if the units continued to be dispatched by MISO.

The effects of these pseudo-tied units have to be managed under the M2M coordination process with PJM. This is problematic, because not all of the constraints that were affected by pseudo-tied resources have been redefined as M2M. Earlier this year, we filed a 206 complaint with the Commission to protest PJM's pseudo-tie requirement for external capacity resources. If FERC grants this complaint or PJM is willing to relinquish this requirement, we recommend that MISO implement firm capacity delivery procedures with PJM in lieu of pseudo-tying. These procedures would guarantee the delivery of the energy from MISO capacity resources to PJM, while maintaining the efficiency and reliability of MISO's dispatch.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2016, importing an average of 5.3 GW per hour in real time. MISO remained a net importer of energy from PJM in 2016, with imports averaging roughly 1.2 GW per hour. Price differences between MISO and neighboring areas create incentives to schedule imports and exports that alter the net interchange between the areas. If interface prices accurately reflect the relative cost difference between the neighboring RTOs (including congestion costs), then scheduling between the RTOs that are consistent with the price differences is efficient and desirable. However, efficient interchange is currently compromised by several shortcomings in the market design, including:

- Flawed interface pricing on market-to-market and other external constraints, and
- Suboptimal and poorly-coordinated interchange scheduling.

Addressing these issues is important because they can lead to inefficient transactions that increase price volatility, reduce dispatch efficiency, increase uplift costs, and sometimes create operating reserve shortages.

Interface pricing. To calculate an accurate congestion price at the interface, an RTO must assume the sources or sinks in the neighboring area. For example, when MISO calculated congestion prices at the PJM interface for imports from PJM, it previously assumed the power would come from all over PJM's system (i.e., all generator locations). This was a good methodology because, in most cases, the marginal generators are located throughout an RTOs footprint. However, PJM has generally assumed that the power sources from a limited number of points near the seam, which is not accurate and tends to inflate the congestion pricing at the interface. MISO recently implemented PJM's approach for the MISO-PJM interface. Unfortunately, our analysis indicates that the PJM approach will result in less efficient imports and exports and raise costs for customers in both regions, but we will monitor the actual results.

Ultimately, we continue to recommend that MISO implement an efficient interface pricing framework by: a) removing all external constraints from its interface prices (i.e., including only MISO constraints), and b) adopting accurate assumptions regarding where imports source and exports sink when when calculating interface congestion.

Interchange Coordination. The most promising means to improve interchange coordination is to allow participants to submit offers to transact within the hour if the spread in the RTOs' real-time interface prices is greater than the offer price (i.e., Coordinated Transaction Scheduling or CTS). MISO worked with PJM to develop and file a CTS proposal and it is scheduled for implementation later this year. Although we support the CTS proposal, we requested that FERC order PJM to eliminate all fees charged to CTS transactions because this will limit its effectiveness. Additionally, we remain concerned that the interface pricing issues described above may diminish the savings achieved by the CTS process.

Demand Response

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. With the resolution of issues related to FERC Order 745 by the U.S. Supreme Court in early 2016, MISO is continuing to seek to expand its DR capability. This includes efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 10.7 GW of DR resources, which includes 4 GW of behind-the-meter generation. However, most of MISO's DR capability is in the form of interruptible load developed under regulated utility programs (referred to as "load-modifying resources" or LMRs). MISO does not directly control LMRs and they cannot set energy prices when they are called.

MISO has also been working with its Load Serving Entities to improve real-time information on the availability of LMRs. Although the information from many of the participants is not fully accurate, MISO's improved operational awareness from this process will improve its ability to maintain reliability. In addition to this improvement, we have recommended a number of other changes related to the integration of LMRs in the MISO markets. These recommendations include modifying the emergency procedures to utilize its DR capability more efficiently.

Table of Recommendations

Although the markets performed competitively in 2016, we make 25 recommendations in this report intended to further improve their performance. Nine of the recommendations are new this year, while 16 were recommended in prior reports. This is not unexpected because many of our recommendations require software changes that can require years to implement. MISO addressed three of our recommendations in 2016 and early 2017, as discussed in Section X.F.

The table shows the recommendations organized by market area. They are numbered to indicate the year in they were introduced and the recommendation number in that year. We indicate whether each would provide high market benefits and whether it can be achieved in the short term. The table also notes the seven "Focus Areas" from MISO's market roadmap process.[4]

SOM Number	Focus Area	Recommendations	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2015-1	3	Expand eligibility for online units to set prices in ELMP and suspend offline pricing.	✓	
2015-2	2,3	Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities	✓	
2014-3	2	Improve external congestion related to TLRs by developing a JOA with TVA.		
2012-5	1,2	Introduce a virtual spread product.		
2016-1	1,3,7	Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load.	✓	
2016-2	3,4	Improve procedures for M2M Activation and Coordination including identifying, testing, and transferring control of M2M Flowgates.	✓	
2016-3	2,7	Enhanced Transmission and Generation Planned Outage Approval Authority.		

[4]
1. Enhance Unit Commitment and Economic Dispatch Processes;
2. Maximize Economic Utilization of Existing and Planned Transmission Infrastructure;
3. Improve Efficiency of Prices under All Operating Conditions;
4. Facilitate Efficient Transactions Across Seams with Neighboring Regions;
5. Streamline Market Administrative Processes that Reduce Transaction Costs;
6. Maximize Availability of Non-Confidential and Non-Competitive Market Information; and
7. Support Efficient Development of Resources Consistent with Long-term Reliability.

SOM Number	Focus Area	Recommendations	High Benefit	Feasible in ST
Operating Reserves and Guarantee Payments				
2014-2	1,3,7	Introduce a 30-Minute reserve product to reflect VLR requirements and other local reliability needs.	✓	
2016-4	1,3,7	Establish regional reserve requirements and cost allocation.		
2016-5	1,5	Reform DAMAP and RTORSGP rules to improve performance incentives, and reduce gaming opportunities and unjustified costs.	✓	
Improve Dispatch Efficiency and Real-Time Market Operations				
2012-12	1,5	Improve thresholds for uninstructed deviations.	✓	✓
2012-16	1,3	Re-order MISO's emergency procedures to utilize demand response efficiently.		✓
2015-4	1	Enhanced tools and procedures to address poor dispatch performance.		✓
2016-6	1	Improve the accuracy of the LAC recommendations.		✓
2016-7	1,5	Improve forecasting incentives for wind resources by modifying deviation thresholds and settlement rules.		
2016-8	1,7	Validation of wind suppliers' forecasts and use results to correct dispatch instructions.		✓
Resource Adequacy				
2010-14	7	Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.	✓✓	
2013-4	7	Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions.		✓
2014-5	7	Transition to seasonal capacity market procurements.		
2014-6	7	Define local resource zones primarily based on transmission constraints and local reliability requirements.		
2015-5	7	Implement Firm Capacity Delivery Procedures with PJM.	✓✓	
2015-6	7	Improve the modeling of transmission constraints in the PRA.	✓	
2015-7	7	Improve the physical withholding mitigation measures for the PRA by addressing uneconomic retirements.		✓
2015-8	7	Improve the limit on the transfer constraint between MISO South and Midwest in the PRA.		✓
2016-9	7	Qualification of planning resources.		✓

I. INTRODUCTION

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. This annual report summarizes this evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets that are designed to efficiently satisfy the needs of the MISO system, which initially encompassed parts of 12 states in the Midwest. In 2013, MISO integrated the MISO South region in Texas, Louisiana, Mississippi, and Arkansas. The MISO markets include:

Day-ahead and real-time energy markets. They utilize the lowest-cost resources to satisfy the system's demands without overloading the transmission network. They provide economic signals to govern short and long-run decisions by participants.

Financial Transmission Rights (FTRs). Congestion revenues collected by MISO through its markets fund FTRs. FTRs allow participants to hedge congestion costs by entitling holders to the congestion price difference between locations in the day-ahead energy market.

Ancillary Services Markets (ASM). These include operating reserves and regulation markets. The ancillary services and energy markets are jointly optimized to allocate resources efficiently. Co-optimization allows prices to fully reflect shortages of and tradeoffs between the products.

Capacity Market. The Planning Reserve Auction (PRA) was implemented in 2013. Because the demand in the PRA does not reflect the reliability value of capacity, this market cannot achieve the purpose of any capacity market – to facilitate efficient investment and retirement decisions.

A number of key market improvements were implemented in 2016 and early 2017, including:

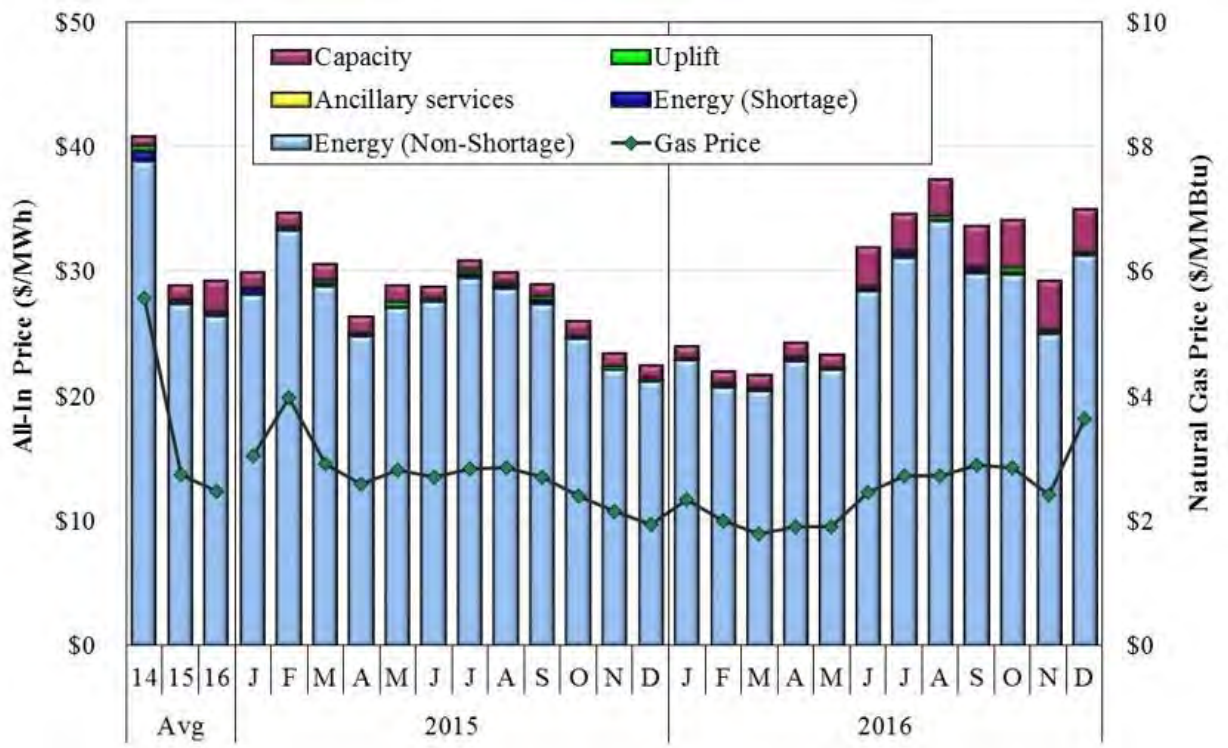
- Settling with SPP and others to create the Regional Dispatch Transfer (RDT) constraint, allowing larger transfers (2500 to 3000 MW) between the Midwest and South subregions;
- Introducing a ramp product in May to allow the system to reduce the costs of satisfying fluctuating system needs;
- Implementing Real-Time Offer Enhancement (RTOE) capability in September, allowing resources to update offers intra-hour to reflect short-term operating limitations.
- Shifting the day-ahead market in November to better align the electricity and gas markets.
- Implementing emergency pricing in July to ensure that additional supply or demand reductions acquired through emergency actions are priced at appropriate shortage levels.
- Modifying the ELMP pricing model to allow more peaking resources to set energy prices.

II. Price and Load Trends

A. Market Prices in 2016

Figure 1 summarizes changes in energy prices and other market costs by showing the "all-in price" of electricity, which is a measure of the total cost of serving load in MISO. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load. We separately show the portion of the all-in energy price that is associated with shortage pricing for any reserve product.

Figure 1: All-In Price of Electricity
2015–2016



The all-in price increased by one percent in 2016 to an average of $29.27 per MWh. The slight increase was driven by increases in capacity clearing prices from the 2016/2017 Planning Resource Auction (PRA). The energy and ancillary services components of the all-in price actually fell 3 percent relative to 2015, largely because of declining fuel prices in the first half of the year and increases in wind production. The average price of natural gas decreased 10 percent from 2015, while Powder River Basin coal prices were virtually unchanged from 2015 to 2016.

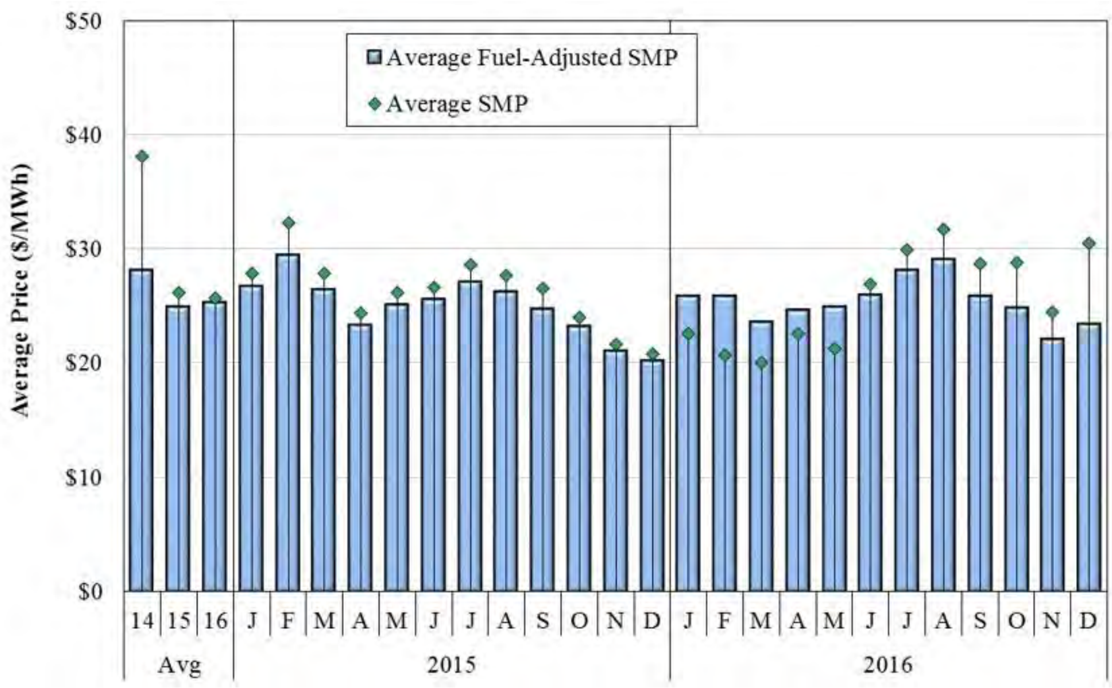
As in prior years, the real-time energy component constituted most of the all-in price. The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected in a well-functioning, competitive market because fuel costs are the majority of most suppliers' marginal production costs. Since suppliers in competitive markets have an incentive to offer marginal cost, fuel price changes should result in comparable offer price changes. However, the figure shows that energy prices rose faster than fuel prices in the summer months because the summer temperatures and loads were higher than normal in 2016.

Higher capacity prices in the Midwest subregion added 8 percent ($2.43 per MWh) to the all-in price in 2016. The PRA clearing price in the 2016/2017 delivery year was $72 per MW-day for most zones in the Midwest versus $2.99 per MW-day in the South, because the transfer constraint between subregions was binding. Despite the higher prices in the Midwest, capacity remains undervalued due to shortcomings in the PRA design that we discuss in this report.

Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs and Price Volatility Make Whole Payments (PVMWPs) made to ensure resources are not harmed when following MISO's dispatch instructions. Lower fuel prices led to lower uplift payments in 2016 and reduced the uplift contribution to the all-in price to 20 cents per MWh. Ancillary services costs remained modest at 9 cents per MWh.

To estimate the price effects of factors other than the change in fuel prices, we calculate a fuel price-adjusted System Marginal Price (SMP) that is based on the marginal fuel in each five-minute interval. To calculate this metric, each real-time interval's SMP is indexed to the three-year average of the price of the marginal fuel during the interval.[5]

Figure 2: Fuel-Adjusted System Marginal Price
2015–2016



5 See Figure A4 in the Appendix for a detailed explanation of this metric.

The average nominal SMP in 2016 fell three percent from 2015. However, the fuel-adjusted SMP *increased* by two percent because of the higher summer loads in 2016. The highest fuel-adjusted SMP occurred in August 2016 when MISO experienced several high-temperature periods and declared a Maximum Generation Alert for the North and Central regions at the end of the month. The fuel-adjusted SMP was also high in July, when MISO declared Hot Weather Alerts throughout the Central and North regions and a Maximum Generation Event (Step 1) on one day. A week later, MISO experienced an Operating Reserve Shortage.

B. Fuel Prices and Energy Production

The continuing decline in fuel prices during 2016 contributed to changes in the generation mix in MISO. In particular, low natural gas prices throughout 2016 increased MISO's output from natural gas-fired units and decreased the generation from coal-fired resources. The following table shows how these changes affected the share of energy produced by fuel type and which generators set real-time energy prices in 2016.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type
2015–2016

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)*		LMP (%)	
	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Nuclear	12,432	12,432	9%	9%	16%	16%	0%	0%	0%	0%
Coal	59,181	53,471	42%	41%	50%	46%	62%	55%	95%	85%
Natural Gas	58,013	55,367	42%	42%	24%	27%	37%	44%	94%	85%
Oil	2,063	1,832	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,603	3,478	3%	3%	1%	1%	1%	1%	2%	2%
Wind	2,412	2,796	2%	2%	7%	8%	1%	1%	45%	32%
Other	1,688	2,076	1%	2%	1%	2%	0%	0%	4%	3%
Total	**139,391**	**131,452**								

** In 2016, we updated our methodology for SMP price-setting to allow for multiple fuels to be marginal in the same interval.*

The lowest-cost resources (coal and nuclear) operate at the highest capacity factors and coal continued to produce the greatest share of energy. Natural gas-fired output grew from 24 percent in 2015 to 27 percent in 2016, yet remains lower than its 42 percent share of capacity. Coal-fired resources now constitute a slightly smaller share of MISO's capacity than last year, and they produced 46 percent of MISO's output in 2016, down from 50 percent in 2015.

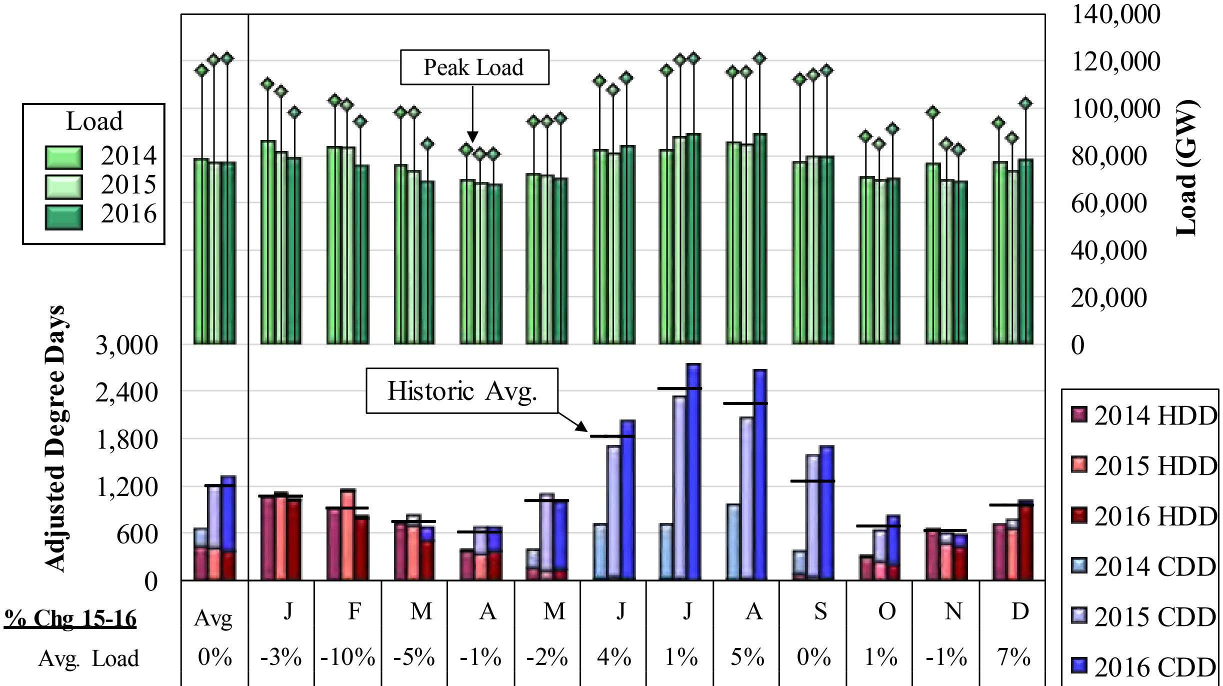
Although natural gas-fired units produce a modest share of the energy in MISO, they play an important role in setting energy prices. Gas-fired units set the system-wide price in 44 percent of all intervals for the year, up from 37 percent in 2015. Gas-fired resources effectively set the system-wide prices in almost all peak hours, because gas rarely sets prices overnight when prices are lower. Congestion frequently causes gas-fired units to set prices in local areas when lower-cost units may be setting the system-wide price. Hence, natural gas-fired resources set LMPs in local areas in 85 percent of all intervals, highlighting why natural gas prices are an important driver of energy prices. Coal-fired resources set the system-wide price in 55 percent of intervals, down from 62 percent in 2015.

The capacity values in Table 1 are planning values, so they are derated from the nameplate level by more than 13 GW. This derating has the largest effect on wind resources that are only two percent of MISO's planning capacity. Although wind resources' share of both energy and capacity is well below 10 percent, wind resources set LMPs in local areas (generally at negative prices) in almost one third of all intervals because they were frequently ramped down to manage congestion.

C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are determined by weather patterns. Figure 3 indicates the influence of weather by showing the heating and cooling needs together with the monthly average load over the past two years. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across six representative locations in MISO.[6]

Figure 3: Heating- and Cooling-Degree Days
2014–2016



% Chg 15-16	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	0%	-3%	-10%	-5%	-1%	-2%	4%	1%	5%	0%	1%	-1%	7%
Degree Days	9%	-6%	-27%	-20%	-1%	-8%	19%	18%	30%	7%	30%	-4%	30%

6 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65 degrees Fahrenheit). To normalize the relative impacts on load of HDDs and CDDs, HDDs are inflated by a factor of 6.07, based on a regression analysis. The historic average degree-days are based on data from 1971 to 2000.

Although the degree days increased in 2016, the average load in MISO remained unchanged compared to 2015 levels. Total degree days increased by nine percent, primarily because the summer and early fall in 2016 were warmer than in recent years. Winter conditions early in the year were significantly milder than normal in most MISO areas, leading to fewer heating-degree days during typically colder months.

Annual Peak Load on July 21

MISO set its annual peak load of 121.0 GW on July 21, which was one GW higher than the peak load in 2015. Actual peak load was roughly five GW lower than the forecasted peak of 125.9 GW from MISO's *2016 Summer Resource Assessment.* On July 21:

- MISO declared a Maximum Generation Event and remained in Conservative Operations through the evening of July 22 because it had forecasted load of nearly 125 GW.
- The real-time load was substantially below the day-ahead and mid-term forecasts (made on the morning of July 21), because storms in Wisconsin, Michigan, and Northern Indiana reduced temperatures and loads in those areas. Additionally, market participants voluntarily curtailed loads of nearly 1,600 MW during the emergency event.
- The day-ahead load forecast was 121.2 GW, and the mid-term load forecast (MTLF) called for approximately 125.5 GW. Given that the MTLF informs commitment decisions, MISO committed resources in real time based on a higher forecast load than actually materialized.
- MISO committed 195 turbines, most of which were ultimately unnecessary because the peak load was much lower than the forecast, causing them to lower real-time prices and leading to $1.6 million in real-time RSG.
- The turbines committed did not set prices because very few were eligible under Extended Locational Marginal Pricing (ELMP). We conducted a simulation that showed that expanding the eligibility rules would have raised peak hour prices by 38 percent on July 21 and lowered real-time RSG by 14 percent.
- Emergency Pricing rules implemented on July 1 called for MISO to apply a proxy offer floor price to all emergency MWs, but the emergency MWs did not set the price because they were not deemed necessary by ELMP.

Other Peak Load Days in 2016

MISO experienced several other weather-related events during the summer months in 2016. In June, high loads and outages in MISO South resulted in substantial congestion into the South, when the RDT constraint was binding. MISO declared Severe Weather Alerts and Conservative Operations and Local Transmission Operators declared emergency conditions on several days. On June 17, MISO issued a Maximum Generation Alert in the South. MISO also experienced several hot periods in August and declared local Conservative Operations for severe flooding conditions in the Amite South and DSG load pockets. On August 29, MISO issued a Maximum Generation Alert for the North and Central regions due to weather conditions.

D. Long-Term Economic Signals

While price signals play an essential role in coordinated commitment and dispatch of units in the short term, they also provide long-term economic signals that govern investment and retirement decisions for generators and transmission. This section evaluates MISO's long-term economic signals by measuring the "net revenue" a new generating unit would have earned in 2016.

Net revenue is the revenue a new unit would earn above its variable production costs if it ran when it was economic to run. A well-designed market should produce net revenue sufficient to support new investment when existing resources are not sufficient to meet the system's needs. Figure 4 and Figure 5 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the prior three years in the Midwest and South regions. For comparison, the figures also show the annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE).

Figure 4: Net Revenue Analysis
Midwest Region, 2014–2016

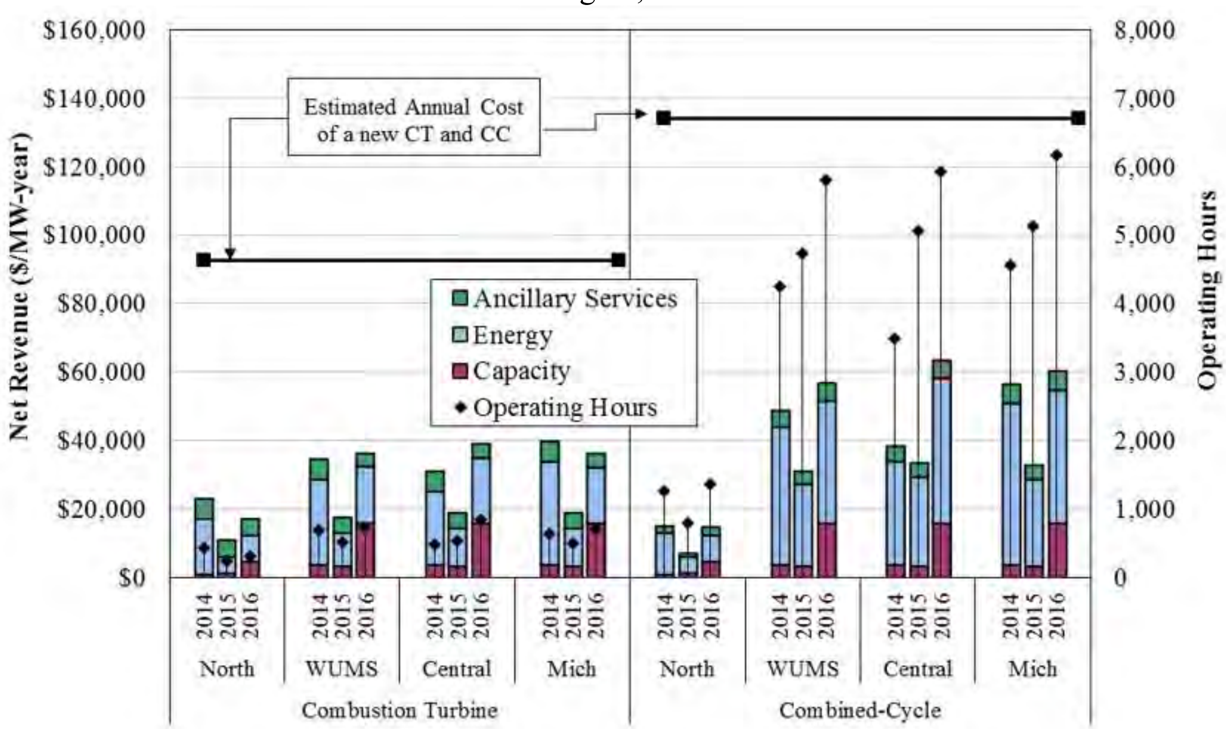
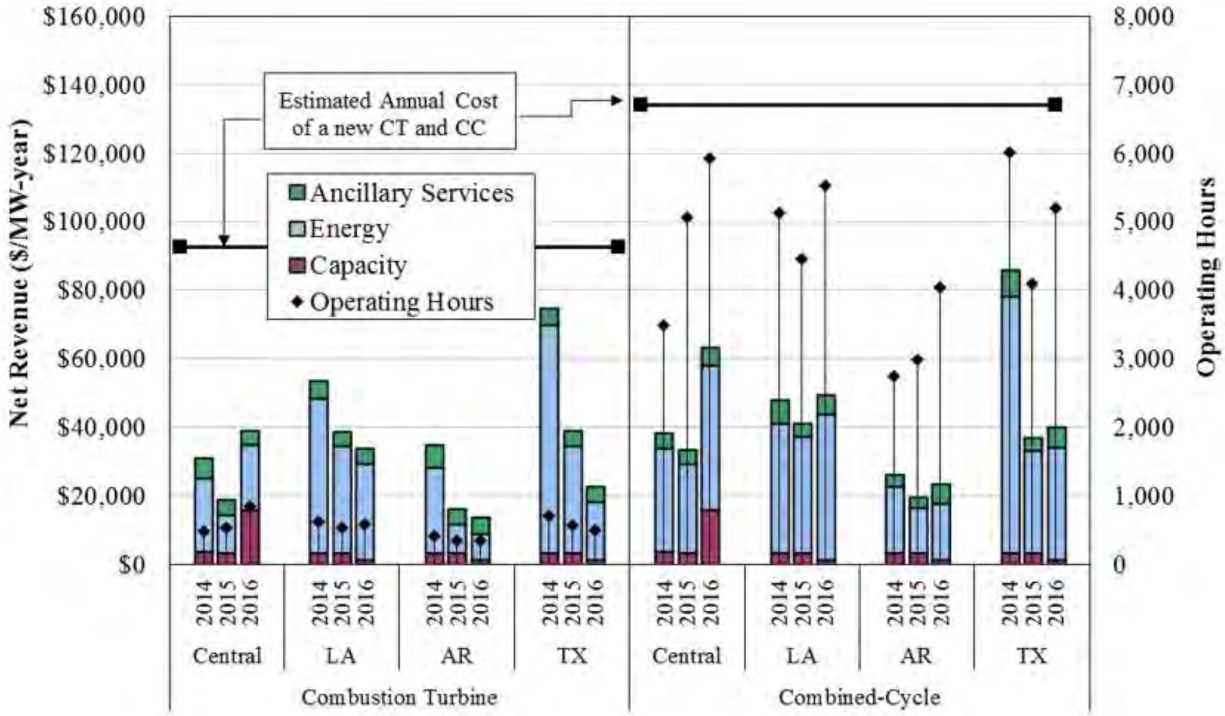


Figure 5: Net Revenue Analysis
South Region, 2014–2016



Note: "Central" refers to the Central region of MISO Midwest and is included for reference purposes.

Net revenues for combustion turbines in the South region generally decreased as capacity prices and congestion levels fell in 2016. Estimated net revenues in the Midwest Region for both types of units increased substantially in 2016 because of higher capacity prices and higher prices during the summer months. Nonetheless, net revenues continue to be substantially less than CONE in all regions. The relatively low net revenues are consistent with expectations, because of the small prevailing capacity surplus and capacity market design issues that we describe in this report.

Capacity market design issues continue to undermine MISO's economic signals. This raises particularly timely concerns, because MISO's capacity surplus is dissipating as resources are facing substantial economic pressure and competitive suppliers are incented to export capacity to PJM. To improve these price signals, we recommend a number of changes to both the energy and capacity markets in this Report. The next section discusses the supply in MISO in more detail and evaluates the design and performance of the capacity market.

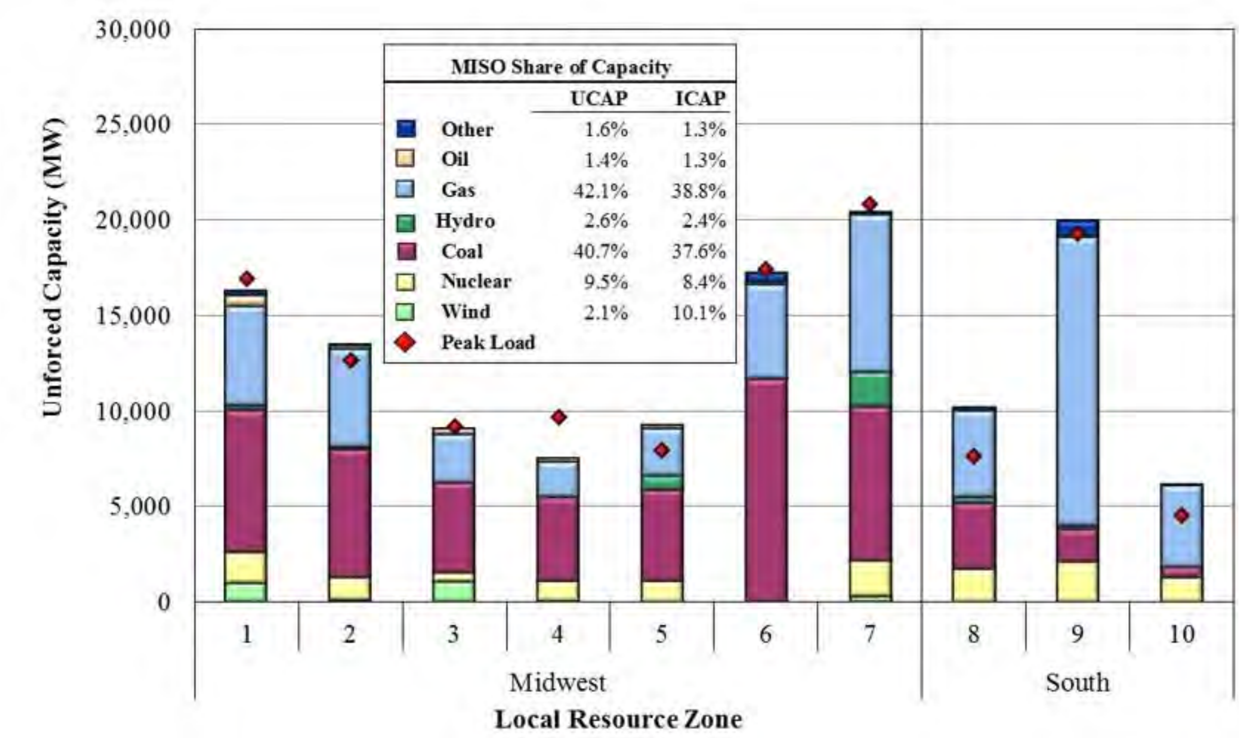
III. Resource Adequacy

This section evaluates the adequacy of the supply in MISO for the upcoming summer and discusses improvements to MISO markets that would promote efficient investment and retirement decisions to satisfy MISO's long-term resource adequacy needs.

A. Regional Generating Capacity

The next two figures show the capacity distribution of existing generating resources by Local Resource Zone. Figure 6 shows the distribution of Unforced Capacity (UCAP) at the end of 2016 by zone and fuel type, along with the 2016 coincident peak load in each zone. UCAP was based on data from the MISO PRA for the 2016/2017 Planning Year. UCAP values account for forced outages and intermittency; therefore, UCAP values for wind units are lower than Installed Capacity (ICAP) values (as shown in the inset table). Hence, although wind is 10 percent of MISO's ICAP, it is only two percent of its UCAP.

Figure 6: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2016



MISO Share of Capacity	UCAP	ICAP
Other	1.6%	1.3%
Oil	1.4%	1.3%
Gas	42.1%	38.8%
Hydro	2.6%	2.4%
Coal	40.7%	37.6%
Nuclear	9.5%	8.4%
Wind	2.1%	10.1%
Peak Load		

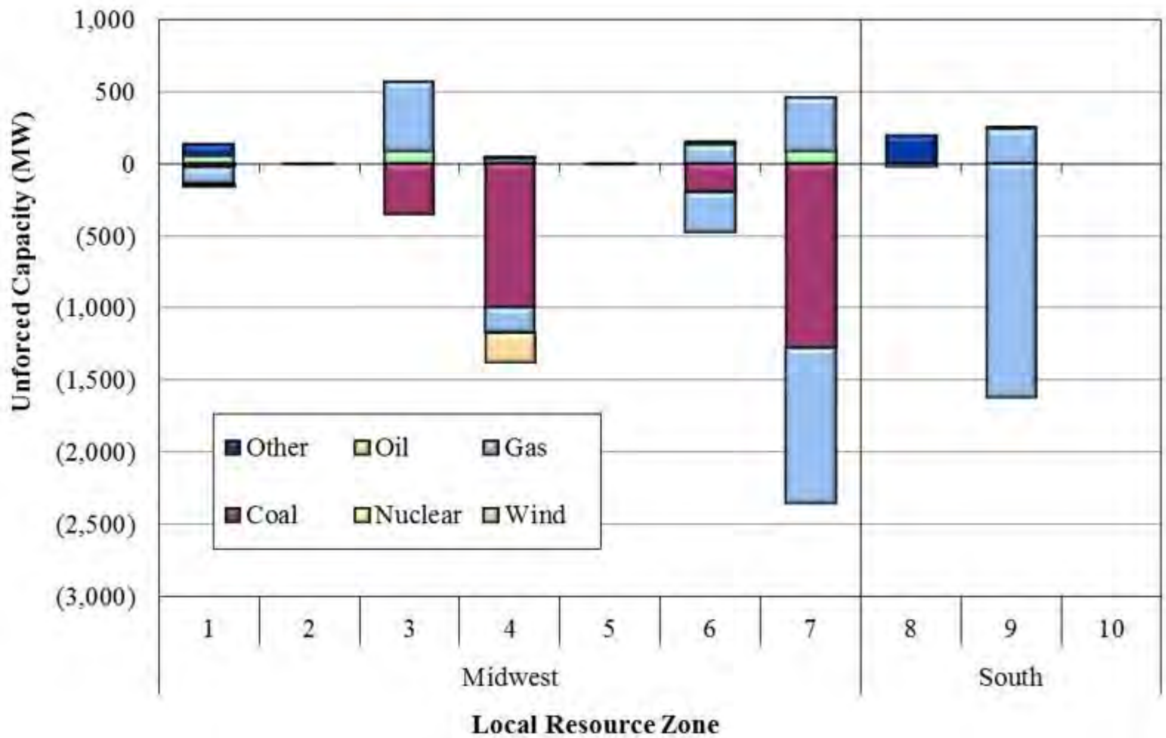
This figure shows that gas-fired resources now account for a larger share of MISO's capacity than any other capacity type including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the South to the Midwest Region when natural gas prices and outage levels are low.

Additionally, because the average energy output from wind units in the western zones (i.e., zones 1 and 3) is generally greater than those units' UCAP credit, the western areas produce substantial surplus energy when wind output is high, resulting in large west-to-east flows and congestion.

B. Changes in Capacity Levels

Capacity levels have been falling in MISO because of accelerating retirements and capacity exports to PJM. Figure 7 shows the capacity additions and retirements during 2016.

Figure 7: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone, 2016



Capacity Losses

In 2016, 6.8 GW of resources exited MISO, of which nearly 4 GW was gas-fired capacity that retired, suspended, or pseudo-tied out of MISO. More than half of these resources were located in the South. In total, more than three GW of lost capacity consisted of coal-fired resources, two-thirds of which was sold into PJM. Capacity exports to PJM have grown rapidly where the price of capacity has been more reflective of its reliability value.

In recent years, the U.S. Environmental Protection Agency (EPA) has issued several environmental regulations that required older coal units to install costly retrofits in order to continue operating, and multiple resources retired in order to avoid incurring those costs. Additional resources have announced their intentions to suspend or retire in 2017.

New Additions

Most new capacity additions in MISO were natural gas-fired resources, totaling more than 2.2 GW. In 2016, 1.4 GW of renewables entered in the Midwest region, including a 100-MW solar farm that entered on December 1, 2016. Additional investment in wind resources may occur in the coming years as Multi Value Projects (MVP) are completed, which include 17 transmission projects that are estimatd to cost more than $6.6 billion. Four of these projects are completed, five are underway and expected to be completed between 2017 and 2019, and the remaining eight are pending. In April 2017, a new gas-fired combined-cycle unit entered MISO.

C. Planning Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2017. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2017 Summer Resource Assessment,* with one notable exception. MISO assumes a transfer limit assumption of 1,500 MW (consistent with the 2017/2018 PRA). We assume a probabilistic derated transfer capability of 2,000 MW, which results in a slightly higher planning reserve margin. Table 2 shows three scenarios that examine how variations in demand response (load-modifying resources or "LMRs") and unusually hot temperatures affect MISO's planning reserve margins.

Table 2: Summer 2017 Planning Reserve Margins

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	Realistic DR	Full DR	Realistic DR
Load				
Base Case	125,020	125,020	125,020	125,020
High Load Increase	-	-	7,211	7,211
Total Load (MW)	125,020	125,020	132,231	132,231
Generation				
Internal Generation	140,850	140,850	140,850	140,850
BTM Generation	4,009	4,009	4,009	4,009
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(2,157)	(2,157)	-	-
Total Generation (MW)	142,701	142,701	139,958	139,958
Imports and Demand Response				
Demand Response***	6,112	4,890	6,112	4,890
Capacity Imports****	3,483	3,483	3,483	3,483
Capacity Exports	(3,636)	(3,636)	(3,636)	(3,636)
Margin (MW)	23,640	22,417	13,686	12,464
Margin (%)	**18.9%**	**17.9%**	**10.9%**	**10.0%**

Notes:
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.
** The MISO Base Case Reserve Margin assumes that 2,157 MW (50/50 scenario) of capacity in MISO South cannot be accessed due to the 2,000 MW Transfer Limit (applying probabalistic derates on the 2,500 MW Transfer Limit) so this reduces the overall MISO Capacity Margin.
*** Demand Response reflects cleared Demand Response for 2017/2018 planning year.
**** Capacity imports reflects cleared imports for 2017/2018 planning year.

The columns in Table 2 include a number of cases:

- Column 1: Base case that assumes that MISO will receive full response from its Demand Response (DR) resources (interruptible load and controllable load management) when they are deployed.
- Column 2: Base case with a "realistic DR" assumption that MISO will only receive 80 percent responses from the DR resources. DR resources are not subject to comparable testing to generators and have not fully performed in the rare cases when they have been deployed. However, MISO's certification requirements, operational awareness of available DR capability from LBAs, and penalties for failing to respond have all improved. Hence, we believe an 80 percent assumed response is realistic.
- Columns 3 and 4: Assuming "Full DR" and "realistic DR" scenarios under hotter than normal summer peak conditions. These cases are based on a "90/10" case (should only occur one year in ten).

The high-temperature cases are important because hot weather can significantly affect *both* load and supply. High ambient temperatures can reduce the maximum output limits of many of MISO's generators, while outlet water temperature or other environmental restrictions cause certain resources to be derated.[7] In its *2017 Summer Assessment*, MISO shows a high-load scenario that includes an estimate of high temperature derates. While we believe this scenario is a realistic forecast of potential high-load conditions, we continue to believe that it likely understates the derates that may occur under high-temperature conditions.

The results in the table show that the capacity surplus varies considerably in these scenarios:

- The baseline capacity margin for the MISO Midwest region is nearly 19 percent, which substantially exceeds the Planning Reserve Margin Requirement of 15.8 percent.
- The high-temperature cases show much lower margins—as low as 10 percent when DR is derated to a realistic level. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no forced outages, which generally range from five to eight percent but may be much higher due to correlated factors (e.g., during periods of extreme temperatures).

Overall, these results indicate that the system's resources should be adequate for summer 2017 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins have been decreasing and will likely continue to fall as resources retire and suppliers continue to export capacity to PJM. Therefore, it remains important for the capacity market to provide the efficient economic signals to maintain an adequate resource base. These issues are discussed in the following three subsections.

[7] There is significant uncertainty regarding the size of these derates, so our number in the table is an average of what was observed on extreme peak days in 2006 and 2012.

D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO 26 weeks in advance. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR), which it granted for the first time in 2012. A SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. The SSR agreement provides for compensation to the market participant during this period of delayed retirement.

In 2016, only one unit in MISO was classified as a SSR and in November 2016, FERC approved the termination of the SSR agreement. This resulted in an estimated savings of $9 million through April 2018, because the resource received more than $0.5 million in gross recovery per month while the agreement was active. On April 1, 2017, MISO entered a SSR agreement with one unit in MISO South.

As retirements accelerate, it is very important that the capacity market and the Attachment Y and SSR processes are well aligned to allow the market to facilitate reasonable retirement decisions and capacity market outcomes. These issues are discussed in the following subsection.

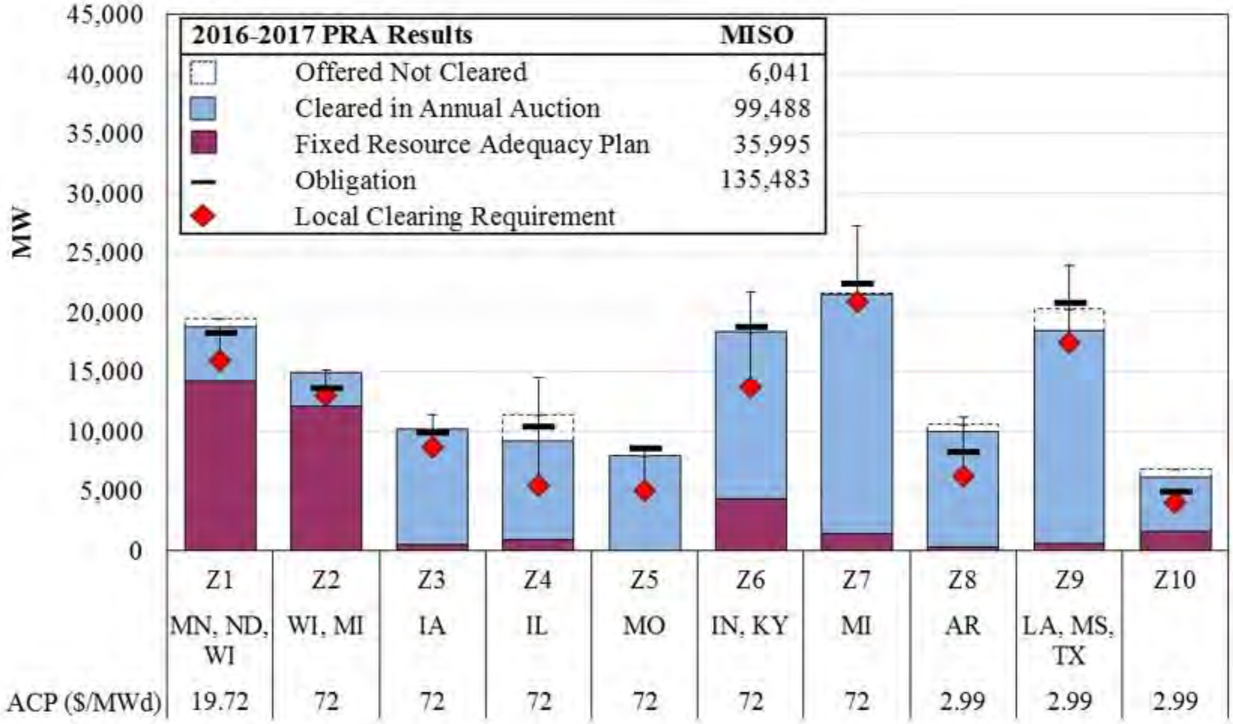
E. Capacity Market Results

MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the Planning Resource Auction (PRA). Resources clearing in MISO's PRA earn a revenue stream that, in addition to energy and ancillary services market revenues, should signal when and where new resources are needed.

Figure 8 shows the combined outcome of the PRA held in April 2016 for the 2016-2017 Planning Year. The figure shows the obligation in each zone, along with the minimum and maximum amount of capacity that can be purchased in each zone. The obligation is set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement, which is equal to the local resource requirement minus the maximum level of capacity imports. The maximum amount is equal to the obligation plus the maximum level of capacity exports.

The auction for the 2016-2017 planning year cleared at $72 per MW-day in most zones in the Midwest Regions, which is more than 25 percent of the Cost of New Entry (CONE), while Zone 1 remained export constrained and cleared at $19.72 per MW-day. The 876 MW transfer limit between the Midwest (Zones 1-7) and South (Zones 8 - 10) regions was binding and resulted in a significantly lower clearing price in MISO South of $2.99 per MW-day.

Figure 8: Planning Resource Auctions
2016–2017 Planning Year



As part of the Settlement Agreement with SPP,[8] MISO may normally schedule up to 2,500 MW of transfer capability from MISO South to MISO Midwest in real time, and this amount has been reliably available. Modeling the transfer constraint with a limit that reflects a probabilistic expectation of available transfer capability would allow MISO to more fully utilize its planning reserves in MISO South and would have affected prices on both sides of the transfer constraint in the PRA. Hence, we recommend MISO adopt a new methodology for establishing the transfer limit in future PRAs.

The 2016/2017 PRA was affected by a number of changes. In particular, MISO:

- Set the initial reference levels for all units to $0 and made other changes to the market power mitigation rules in response to a December 2015 Order from FERC (Resources can still request facility-specific reference levels based on going-forward costs);
- Adjusted the zonal import limits so that they now account for capacity exports from a zone, which is in line with our recommendation made in the 2014 SOM; and
- Reduced the transfer limit between the South and Midwest regions to 876 MW, well below the reasonably expected transfer capability under the RDT; and
- Allowed Attachment Y suspended units to offer into the capacity auction.

8 Agreement with MISO, SPP, and other first tier entities filed October 15, 2015 in docket EL14-21-000.

Additional changes were approved by FERC for the 2017/2018 PRA, which include:

- Imposing physical withholding at the affiliate level, as opposed to the market participant level;
- Excluding LMR Demand Resources, Energy Efficiency Resources, and External Resources from mitigation in the PRA;
- Allowing market participants to use default technology-specific avoided costs for the calculation of the Facility Specific References Levels (FSRLs); and
- Including a formulaic method for implementing a Going Forward Cost (GFC) in the MISO tariff, which is currently contested on the issue of amortizing capital expenses.

In the 2017/2018 capacity auction, the transfer constraint between MISO South and Midwest was expanded to 1,500 MW. This change, together with the PRA's vertical demand curve, led to a historically low auction clearing price of $1.50 per MW-day throughout the entire MISO footprint. This price is close to zero and fails to reflect the true value of capacity in MISO. In addition, the year-over-year volatility in MISO's auction clearing prices creates uncertainty, leading to highly unpredictable expected future revenue streams for long-term investment decisions. These concerns are discussed in the next subsection.

F. Capacity Market Design

The demand for capacity in the PRA continues to poorly reflect its true reliability value, which undermines its ability to provide efficient economic signals for investment and retirement decisions. Three design flaws undermine the performance of the PRA capacity market: (1) the current "vertical demand curve"; (2) barriers to participation affecting units with retirement plans within the planning year; and (3) the local resource zones that do not adequately reflect transmission limitations. In addition to these three design flaws, we discuss MISO's proposal to reform the capacity market in competitive retail areas at the end of this subsection.

Sloped Demand Curve

The PRA includes a single capacity requirement for each LSE and a deficiency price if the market is short, which is effectively a vertical demand curve. The marginal cost of selling capacity for most units is close to zero, so a vertical demand curve will predictably establish clearing prices close to zero (if supply is not withheld). In addition, the vertical demand curve is inconsistent with the underlying reliability value of excess capacity beyond the planning requirement. The implication of the vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity will improve reliability and lower energy and ancillary services costs for consumers (although these effects diminish as the surplus increases).

To address this flaw, we provided comments to FERC and recommended in prior *State of the Market Reports* that Module E of the Tariff be modified to implement a sloped demand curve.[9] A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power. This is because a market with a vertical demand curve is highly sensitive to withholding. Clearing at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless because the foregone capacity sales would otherwise be priced at close to zero. The need for a sloped demand curve will increase as planning reserve margins fall toward the minimum requirement level as a result of significant amounts of capacity exiting MISO.

LSEs and their ratepayers should benefit from a sloped demand curve. LSEs in MISO have generally built resources to achieve a small surplus over the minimum requirement because:

- Investment in new resources is "lumpy," occurring in increments larger than necessary to match the gradual growth in a LSE's requirement; and
- The costs of being deficient are large.

Under a vertical demand curve, the cost of the surplus must entirely be borne by the LSEs' retail customers because LSEs will generally receive very little capacity revenue to offset the costs that they incurred to build the resources. This additional capacity provides reliability value to MISO, so the fact that LSEs receive no capacity revenues is inefficient. Adopting a sloped demand curve would benefit most regulated LSEs. Table 3 illustrates this conclusion.

The table shows how hypothetical LSEs are affected by a sloped demand curve when they hold varying levels of surplus capacity beyond the minimum capacity requirement. The scenarios share the following assumptions: (1) a LSE with 5,000 MW of minimum required capacity; (2) net CONE of $65,000 per MW-year and demand curve slope of -0.01 (matching the slope of the NYISO curve); and (3) a market-wide surplus of 1.5 percent, which translates to an auction clearing price of $4.74 per kW-month ($54.85 per kW-year).

For each of the scenarios, we show the amount that the LSE would pay to or receive from the capacity market, along with the carrying cost of the resources the LSE built to produce the surplus. Finally, in a vertical demand curve regime where the LSE will not expect to receive material capacity revenues for its surplus capacity, all of the carrying cost of the surplus must be paid by the LSE's retail customers. The final column shows the portion of the carrying cost borne by the LSE's retail customers under a sloped demand curve.

9 See "Motion to Intervene Out of Time and Comments of the Midwest ISO's Independent Market Monitor," filed September 16, 2011, in Docket No. ER11-4081.

Table 3: Costs for a Regulated LSE Under Alternative Capacity Demand Curves

LSE Surplus	Market Surplus	Capacity Market Revenues ($Million)	Carrying Cost of Surplus ($Million)	Carrying Cost Borne by Retail Load	Surplus Cost: Sloped Demand Curve	Surplus Cost: Vertical Demand Curve
1.0%	1.5%	$-1.43	$3.25	100%	$4.68	$3.25
2.0%	1.5%	$1.41	$6.50	78%	$5.09	$6.50
3.0%	1.5%	$4.25	$9.75	56%	$5.50	$9.75
4.0%	1.5%	$7.10	$13.00	45%	$5.90	$13.00

These results illustrate three important dynamics associated with the sloped demand curve:

- *The sloped demand curve does not raise the expected costs for most regulated LSEs*. In this example, if a LSE fluctuates between a surplus of one and two percent, its costs will be virtually the same under the sloped and vertical demand curves.
- *The sloped demand curve reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE for surpluses between one and four percent vary by only 26 percent, compared to 300 percent under the vertical demand curve.
- *A smaller share of the total costs are borne by retail customers*. Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds that of the market.

The example above shows that a sloped demand curve will not raise the costs for the vertically-integrated LSEs that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's LSEs in satisfying their planning reserve requirements, in addition to providing efficient market signals to other types of market participants, such as unregulated suppliers, competitive retail providers, and capacity importers and exporters.

Coordination with Attachment Y Process

The second issue with MISO's current capacity market concerns the participation of resources with Attachment Y applications to retire. Resources that have submitted Attachment Y filings for retirement with effective dates during the planning year may lose their interconnection rights and cannot satisfy their capacity obligations after the effective date by deferring retirement.

The PRA should be a process that assists suppliers in making efficient decisions regarding their resources, including whether to retire their units. In order to do this, MISO would need to modify the PRA rules to allow:

- Units with Attachment Y retirement requests to participate in the PRA and, if they clear, to either a) defer the effective date of the retirement, or b) retire the unit during the planning year if MISO determines it is not needed during the period when it would be unavailable. Absent this flexibility, such units would have to procure substitute capacity for the balance of the planning year. This risk is an inefficient barrier to participating in the PRA.
- Units under SSR contracts to participate in the PRA as price takers without undue risk. There should be an assurance that either a) the SSR contract will not be terminated prior to the end of their capacity obligation, or b) if the SSR contract is terminated prior to the end of the capacity obligation period, a unit's capacity obligation will also terminate.

These changes to the RAC and the Attachment Y processes will allow MISO's capacity market to operate more efficiently and facilitate better decisions by market participants. The latter change to allow units to be unavailable for a portion of the planning year is consistent with the precedence for several other types of capacity resources that are only available during the summer season, including units that are not winterized, units that operate with PPAs that are considered "Diversity Contracts," and load-modifying resources.

One recommended change that would substantially mitigate these concerns is the adoption of a seasonal capacity market. This would better align the revenues and requirements of capacity with the value of the capacity. In this construct, there should be consistently applied requirements that resources are available for the duration of the season.

Local Capacity Zone and Seasonal Issues

The third issue with MISO's current capacity market relates to definitions of local resource zones. Currently, a local resource zone cannot be smaller than an entire LBA. However, capacity is sometimes needed in certain load pockets within LBAs. A good example of this type of requirement is the Narrow Constrained Areas (NCAs) in MISO South where the addition of fast-start capacity would be extremely valuable. Hence, we recommend that MISO's local resource zones be established based primarily on transmission deliverability and local reliability requirements.

Additionally, MISO is proposing to procure capacity on a seasonal basis, which we believe would be beneficial. MISO's latest proposal would define two seasons, summer and winter. We have recommended that MISO define four seasons, which would facilitate savings for participants. First, it would allow high-cost units to suspend during the shoulder months or not keep the unit staffed in the months when they are unlikely to be economic to dispatch. Second, it would allow suppliers to retire or suspend units at four points in time during the year (between seasons) without having to purchase replacement capacity. This reduces the risks and costs of supplying capacity and should, therefore, ultimately reduce costs to MISO's consumers.

Proposed Capacity Market Changes in Competitive Retail Areas

A well-functioning capacity market that provides efficient price signals would produce sizable benefits for MISO by:

- Coordinating efficient capacity imports and preventing inefficient exports;
- Supporting a vibrant forward market (bilateral contracts);
- Facilitating low-cost merchant investment; and
- Ultimately, generating substantial savings for MISO's consumers.

Ideally, the MISO capacity market should be structured to achieve these benefits in all areas. In competitive retail areas (CRAs) and for competitive suppliers, however, the capacity market is particularly important to facilitate investment and retirement decisions that will maintain adequate resources (i.e., satisfy planning reserve requirements). Competitive suppliers whose resources are key for satisfying the resource adequacy needs in CRAs rely on the market to decide whether to build, retire, or export resources. However, the current PRA is not designed to provide efficient long-term economic signals for competitive suppliers and loads.

In November 2016, MISO filed a capacity market design for CRAs to address this problem. We found this proposal to be unsound and ultimately FERC agreed with our concerns and rejected it in February 2017. However, we worked with MISO to develop a prompt auction alternative that would produce efficient prices for competitive suppliers and loads. This alternative is based on MISO's existing PRA. It would optimize the procurements and prices in the CRAs, while allowing the procurements and prices outside of the CRAs to be determined by MISO's existing market rules. We encourage MISO to reconsider this alternative or similar design improvements to improve the economic signals provided to MISO's competitive suppliers and loads.

IV. DAY-AHEAD MARKET PERFORMANCE

MISO's spot markets for electricity operate in two time frames: real time and day ahead. The real-time market reflects actual physical supply and demand conditions. The day-ahead market operates in advance of the real-time market. The day-ahead market is largely financial, establishing financially-binding, one-day forward contracts for energy and ancillary services.[10] Resources that clear in the day-ahead receive commitment and scheduling instructions based on day-ahead results, and they must perform these contractual obligations or be charged the real-time price for any products not supplied.[11] Both the day-ahead and real-time markets continued to perform competitively in 2016.

The performance of the day-ahead market is important for the following reasons:

- Because most generators in MISO are committed through the day-ahead market, good market performance is essential to efficient commitment of MISO's generation;[12]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

A. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market, because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, a number of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead market, such as wind or load forecast error, real-time output volatility, and forced generation or transmission outages. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge well over longer timeframes (monthly or annually).

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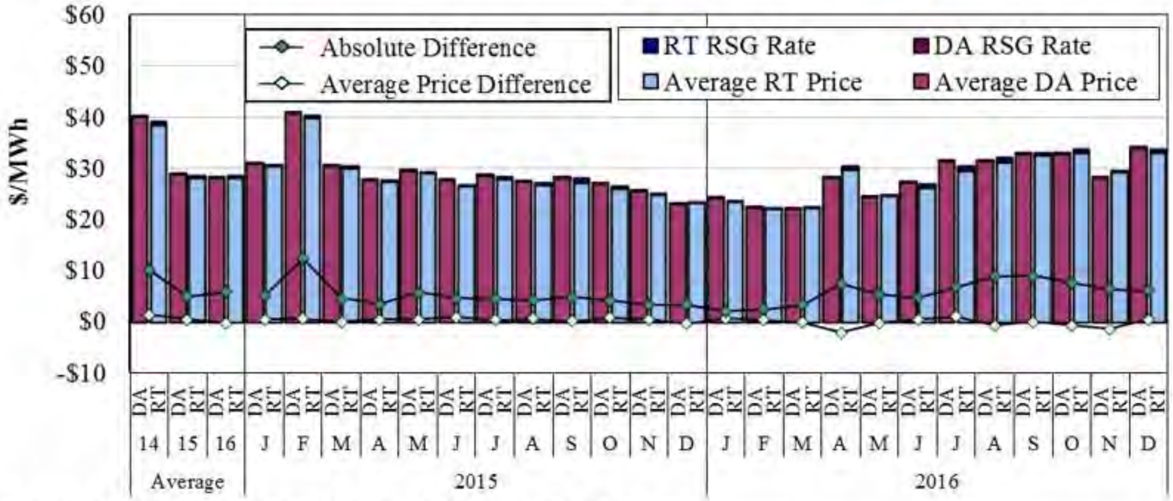
10 In addition to the normal day-ahead commitment, MISO utilizes the Multi-Day Forward Reliability Assessmement Commitment process to commit resources in the day-ahead in order to satisfy reliability requirements in certain load pockets that may require long-start-time resources.

11 In addition, resources with day-ahead schedules that are derated in real time or not following real-time instructions are subject to allocation of of the Day-Ahead Deviation Charge (DDC) or Constraint Management Charge (CMC). Virtual supply and physical transactions scheduled in the day-ahead market are subject to CMC and DDC allocations. Virtual demand bids are only subject to CMC.

12 In between the day-ahead and real-time markets, MISO evaluates the day-ahead results relative to the forecasted capacity needs for the next day. Based on this Forward Reliability Assessment Commitment (FRAC), MISO may start additional capacity not committed in the day-ahead market.

Figure 9 shows monthly and annual price convergence statistics. The upper panel shows the results for only the Indiana Hub, while the table below shows Indiana Hub and six other hub locations in MISO. Because real-time RSG charges (allocated partly to deviations between real-time and day-ahead schedules) tend to be much larger than day-ahead RSG charges (allocated to day-ahead energy purchases), the table shows the average price difference adjusted to account for the difference in RSG charges.

Figure 9: Day-Ahead and Real-Time Prices
2015–2016



Average DA-RT Price Difference Including RSG (% of Real-Time Price)

	14	15	16	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
	Average			2015												2016											
Indiana Hub	3	1	-1	1	1	0	1	2	3	1	2	0	3	2	-2	2	1	-1	-7	-1	1	3	-2	0	-2	-5	1
Michigan Hub	7	1	0	7	6	-1	2	0	0	0	0	-3	2	3	0	4	3	-1	-6	4	0	5	-9	-2	4	-1	2
Minnesota Hub	1	2	-1	-1	0	-1	2	3	-1	3	0	-2	14	5	3	4	5	-3	2	6	-5	0	-6	-2	-2	2	-6
WUMS Area	2	1	-1	1	0	2	4	1	3	3	0	1	1	-1	0	4	3	0	0	1	-3	-5	-7	1	4	1	-6
Arkansas Hub	-3	1	0	-3	3	-3	4	3	3	-3	0	0	0	6	4	2	2	-3	-3	7	4	-1	0	-3	-2	-6	0
Louisiana Hub	-6	-2	-2	0	2	-10	-2	0	-10	1	-5	0	0	-1	4	2	3	-2	2	1	-14	-1	-4	-3	1	0	1
Texas Hub	-1	-4	1	-1	1	-5	4	-10	4	0	-7	-2	-12	-15	3	1	6	3	-18	13	2	-3	1	2	3	-1	2

Day-ahead premiums in 2016 averaged negative 0.4 percent, or essentially zero, after adjusting for the Day-Ahead and Real-Time Deviation Charges (DDC), which averaged $0.06 and $0.48 per MWh respectively. However, there were a number of congestion episodes that resulted in substantial transitory divergence:

- Increases in planned and unplanned outages of transmission and generation contributed to significant congestion in the spring. Two market-to-market constraints that are primarily affected by inflexible wind in PJM contributed to more than half of the total congestion in the spring. Unplanned outages contributed to congestion on both of these constraints.
- Generator and transmission outages in the South led to a large amount of real-time congestion in Texas at the end of April and congestion in Louisiana and Texas during the summer months.
- High quantities of generator outages and increased wind output contributed to periods of substantial congestion in the fall.

The day-ahead market can be slow to react to these periods of substantial real-time congestion, in part because participants must engage in high-risk day-ahead market trades (i.e., virtual load at some locations and virtual supply at others) to arbitrage them. We have recommended a virtual spread product that would allow a participant to make price-sensitive offers in the day-ahead market to buy or sell only the flow over the network between two locations. This would lower the risk of arbitraging the congestion-related differences between the two markets and improve convergence of the congestion in the day-ahead and real-time markets.

B. Virtual Transactions in the Day-Ahead Market

A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. As such, virtual day-ahead purchases or sales cannot perform in real time and, therefore, settle against the real-time price. Virtual transactions are essential facilitators of price convergence because they arbitrage price differences between the day-ahead and real-time markets. Figure 10 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It also shows components of daily virtual bids and offers in the day-ahead market in 2015 and 2016. The virtual bids and offers that did not clear are shown as the transparent areas.

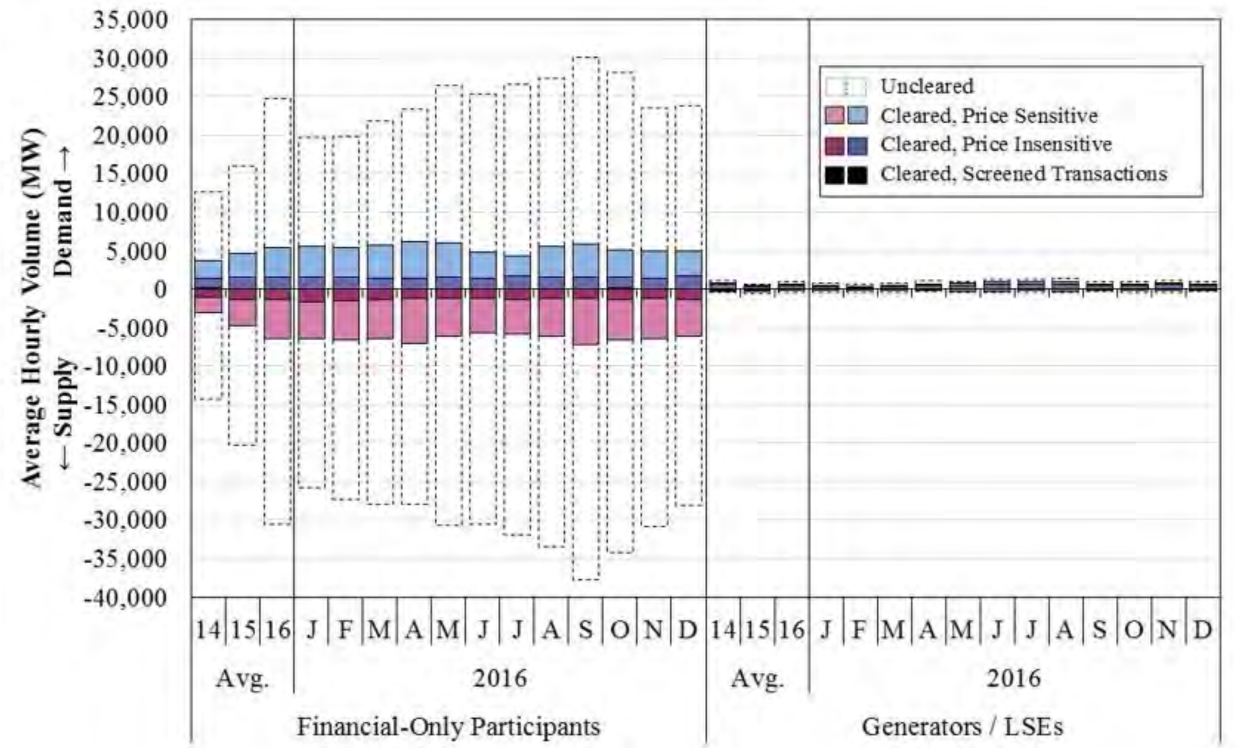
Figure 10 distinguishes between bids and offers that are price-sensitive and those that are price insensitive (i.e., those that are very likely to clear), because price-sensitive transactions are much more valuable in providing liquidity in the day-ahead market and facilitating price convergence. Bids and offers are considered price-insensitive when demand is bid at more than $20 above an "expected" real-time price or supply is offered at $20 below an expected real-time price.[13] In such instances, the participants are effectively indicating a preference for the transaction to clear regardless of the price.

Price-insensitive bids and offers that contribute to a significant difference in congestion at a location between the day-ahead and real-time markets are labeled "Screened Transactions." We routinely investigate these because they generally do not appear rational and lead to price divergence. Therefore, they may represent an attempt to manipulate the day-ahead market.

Figure 10 shows that offered volumes increased by more than 50 percent from last year. Several market participants submitted "backstop" bids, which are bids and offers priced well below (in the case of demand) or above (supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

13 The "expected" real-time price is based on an average of recent real-time prices in comparable hours.

Figure 10: Virtual Load and Supply in the Day-Ahead Market
2015–2016



Cleared transactions rose 24 percent to 12.6 GW per hour. The increase in both offers and cleared transactions was largely driven by the activity of financial traders. Financial participants, who tend to offer more price-sensitively than physical participants, provided key liquidity to the day-ahead market. The also continued to help moderate the effects of under-scheduled wind in the day-ahead market.

The share of Screened Transactions, which are transactions that may constitute manipulation, fell to less than one percent. In most cases, such transactions do not ultimately raise manipulation concerns. However, we did find conduct from one participant in 2016 that warranted the imposition of virtual bidding restrictions at specific locations. The restrictions remained in place for three months per Module D of the MISO Tariff.

Price-insensitive transactions overall continued to constitute a substantial share of virtual transactions. These transactions occur for two primary reasons:

- To establish an energy-neutral position between two locations to arbitrage congestion-related price differences between the day-ahead and real-time markets; and
- To balance the participant's portfolio to avoid RSG deviation charges assessed to net virtual supply, which is deemed to cause RSG under MISO's cost allocation.

We identify “matched” virtual transactions, which are the subset of price-sensitive transactions whereby the participant clears both insensitive supply and insensitive demand that offset one another in a particular hour. The average hourly volume of matched transactions in 2016 fell by 11 percent from 2015. To the extent that matched transactions are attempting to arbitrage congestion-related price differences, we believe that a virtual spread product that would allow participants to engage in these transactions price-sensitively would be more efficient.

Therefore, we continue to recommend that MISO implement a virtual spread product. Participants using such a spread product would specify the maximum congestion difference between two points that they are willing to pay (i.e., schedule a transaction). This product would settle only on the difference in the congestion and loss components of the LMP, so the participant would bear no energy price risk and would not create a deviation that could cause MISO to be capacity-deficient. Comparable products exist in both PJM and ERCOT.

C. Virtual Profitability

The rate of gross virtual profitability fell from $0.76 per MWh in 2015 to $0.63 per MWh in 2016, which is consistent with increased liquidity and good price convergence. The transactions by financial participants were more profitable than those participants that own generation or serve load, which actually lost $0.11 per MWh on average. Transactions that promote convergence are generally profitable (e.g., selling virtual supply at high day-ahead prices), while those that lead prices to diverge are generally unprofitable.

Virtual supply profitability averaged $0.95 per MWh, although more than half of these profits were offset by real-time RSG costs allocated to net virtual supply. Virtual demand profitability was lower at $0.29 per MWh, which reflects good convergence in 2016 and the fact that it is not allocated real-time RSG charges because vitual demand is generally a “helping deviation”. Low virtual profitability is consistent with an efficient day-ahead market, which is important because the day-ahead market coordinates the daily commitment of MISO’s resources. Although overall profitability is a positive indicator, the next subsection contains a more detailed analysis of virtual transactions to determine the share that are improving day-ahead market outcomes.

D. Benefits of Virtual Trading in 2016

We conducted an empirical analysis of virtual trading in MISO in 2016 that evaluated virtuals’ contribution to the efficiency of the market outcomes. We determined that 57 percent of all cleared virtual transactions in MISO were efficiency-enhancing. We identified efficiency-enhancing virtuals as those that were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price). We did not include profits from un-modeled constraints or the loss factors in this determination, because profits on these factors do not lead to more efficient day-ahead market outcomes.

We also identified a small amount (nine percent) of virtual transactions that were unprofitable but efficiency-enhancing because they led to improved price convergence. This happens when virtual transactions respond to a real-time price trend but overshoot, so they are ultimately unprofitable at the margin. Virtual transactions that did *not* improve efficiency are those that were unprofitable based on the energy and congestion on modeled constraints. Table 4 shows the total MWhs of cleared virtual transactions that were and were not efficiency-enhancing by market participant type.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant
2016

	Financial Participants		Physical Participants		Total	
	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Total
Efficiency - Enhancing Virtuals	6,790	*58%*	400	*47%*	7,190	*57%*
Non - Efficiency - Enhancing Virtuals	4,956	*42%*	456	*53%*	5,412	*43%*

In reviewing the total profits and losses of the virtual transactions, we found that the profits of the efficiency-enhancing virtual transactions exceeded the losses of the inefficient transactions by $65 million in 2016, a 15 percent increase over 2015.

This estimate significantly understates the net benefits of the virtual transactions because it measures the profits at the margin. In other words, the total benefit is much greater than the marginal benefit, because:

- The profits of efficient virtual transactions become smaller as prices converge.
- The losses of inefficient virtual transactions get larger as prices diverge.
- Hence, the total net benefit of virtual transactions were much larger than $65 million in 2016.

To accurately calculate this total benefit would require one to rerun all of the day-ahead and real-time market cases for the entire year. However, this analysis allows us to estimate with a high degree of confidence that virtual trading was greatly beneficial in 2016.

Some have argued that virtual transactions can sometimes profit but not produce efficiency benefits. We agree and have identified these transactions and excluded them from the accounting above. The profits in this category include those associated with un-modeled constraints in the day-ahead market and differences in the loss components between the two markets. The net profits in this category totaled $34.7 million, roughly two-thirds of which was attributable to un-modeled constraints. It is important to note that these profits do not indicate a concern with virtual trading, but rather opportunities for MISO to improve the consistency of its modeling between the day-ahead and real-time markets.

V. Real-Time Market

The performance of the real-time market is very important because it governs the dispatch of MISO's resources and sends economic signals that facilitate scheduling in the day-ahead market and longer-term decisions. This section evaluates a number of aspects of the pricing and outcomes in the real-time market, including the uplift costs MISO incurs in operating the system.

A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly and supply flexibility is restricted by the physical limitations of the resources and network. The day-ahead market operates on a longer time horizon with more commitment options and additional liquidity provided by virtual transactions. Because the real-time market is limited in its ability to anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some units moving as quickly as they can toward their optimal economic output). This results in transitory price spikes (upward or downward). Real-time price volatility in MISO increased slightly in 2016, which was due in part to severe weather patterns throughout the summer, as well as the increase in transmission congestion (which is a source of volatility). Figure 11 compares 15-minute price volatility at representative locations in MISO and in three neighboring RTOs.

Figure 11: Fifteen-Minute Real-Time Price Volatility
2016

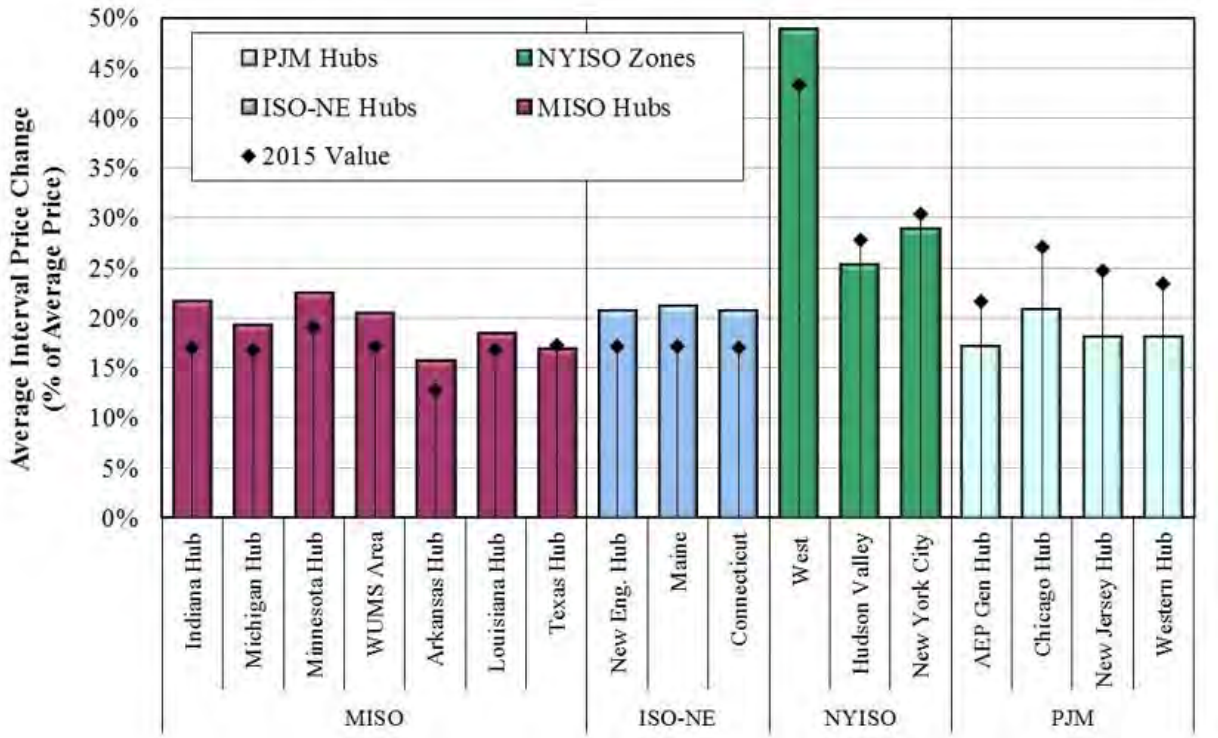


Figure 11 shows that MISO generally had similar price volatility as compared to PJM and ISO New England in 2016, which is impressive because:

- MISO runs a true five-minute real-time market (producing a new real-time dispatch every five minutes).
- PJM and ISO New England dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility and lower volatility (although it is not as effective in balancing supply and demand).
- NYISO dispatches the system every five minutes like MISO, but it has a look-ahead dispatch system that optimizes multiple intervals. All else equal, the multi-period optimization reduces price volatility.

Volatility in MISO primarily occurs when ramp constraints bind and cause sharp price movements, which tends to happen when:

- Actual load is changing rapidly, including non-conforming load associated with industrial facilities that can change sharply and without advance notice;
- Net Scheduled Interchange (NSI) changes significantly;
- A large quantity of generation is either starting up or shutting down; or
- The load-offset parameter is not set optimally to manage anticipated ramp changes.

MISO has made significant efforts to improve the commitment, dispatch, and pricing of units in recent years. The efficiency of real-time commitments improved with the introduction of a Look-Ahead Commitment (LAC) tool. MISO also implemented a “Ramp Capability” product in the spring of 2016, which has resulted in the real-time market holding additional ramp capability when the projected benefits exceed its cost. This product has improved MISO’s ability to manage the system’s ramp demands and contributed to lower price volatility.

B. Evaluation of ELMP Price Effects

In March 2015, MISO implemented the Extended Locational Marginal Pricing algorithm (ELMP). ELMP is intended to improve price formation in the day-ahead and real-time energy and ancillary services markets by causing prices to better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP is a reform of the current price-setting engine that affects prices but does not affect the dispatch. ELMP reforms pricing by allowing Fast-Start Resources,[14] some Demand Response resources, and emergency resources to set prices when they are:

- *Online* and deemed economic by the ELMP model; or

14 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff term as a “Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less….”

- *Offline* and deemed economic to set prices during transmission or energy shortage conditions.

The first of these reforms was intended to remedy issues that we first identified shortly after the start of the MISO energy markets in 2005. The pricing algorithm in MISO's UDS dispatch software does not always reflect the true marginal cost of the system. This is because inflexible high-cost resources are frequently not recognized as marginal even though they are needed to satisfy the system's needs. The most prevalent class of such units is online natural gas-fired turbines that often have a narrow dispatch range. Because it is frequently not economic to turn them off since they are the lowest cost means to satisfy the energy needs of the system, it is appropriate for the energy prices to reflect the running cost of these units. It undermines real-time prices when these resources are economic, but not refected in prices. Ultimately, this will:

- Increase the need to make RSG payments to cover these units' as-offered costs;
- Not provide efficient incentives to buy in the day-ahead market when lower-cost resources could be scheduled that would reduce reliance on high-cost peaking units in real time;
- Not provide efficient incentives for participants to schedule exports or imports, which can prevent lower-cost energy from being imported to displace the higher-cost peaking units.

Accordingly, the objective of the online pricing reforms in ELMP is to address these inefficiencies and improve price formation in MISO's energy markets.

The second reform allows *offline* fast-start resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. It is efficient for offline resources to set the price only when a) they are feasible (can be started quickly to address the shortage), and b) they are economic for addressing the shortage. However, when units that are neither feasible nor economic to start are allowed to set energy prices, the resulting prices will be inefficiently low.

ELMP had a modest effect on MISO energy prices in 2016:

- ELMP lowered market-wide real-time prices by $0.01 per MWh on average.
  - The online pricing component of ELMP has raised real-time prices in 7.1 percent of intervals market-wide, resulting in an average increase of $0.09 per MWh.
  - The offline pricing component has affected prices in only 0.6 percent of intervals, but the effects are larger because this component mitigates shortage pricing. On average, it lowered real-time energy prices in 2016 by $0.11 per MWh.
- At congested locations, ELMP affected real-time prices in roughly 10 percent of the intervals and had effects ranging from -$0.81 to $1.34 per MWh on a monthly average basis at the most affected locations.
- As expected, ELMP had almost no effect in the day-ahead market because the overall supply is much more flexible, including virtual transactions.

Evaluation of Online Pricing

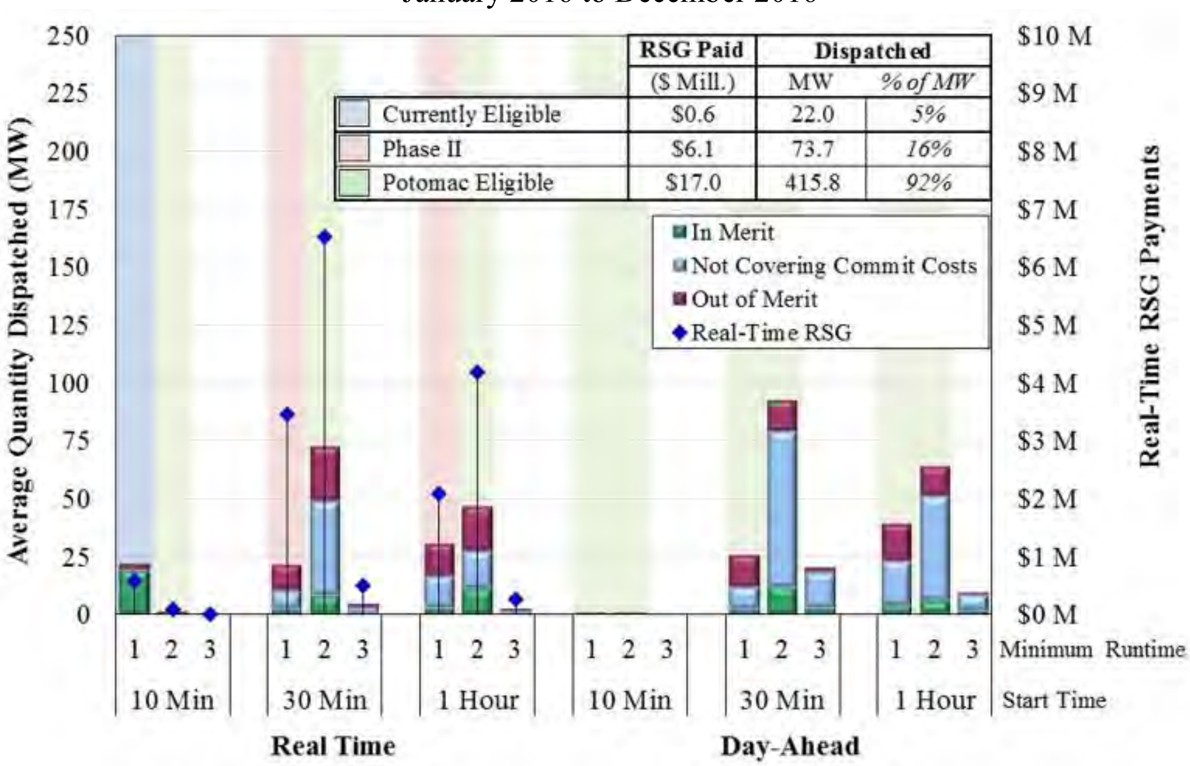
Our prior evaluations concluded that the relatively small effects of the online pricing was attributable to the fact that a very small share of MISO's resoures were initially eligible to set prices. This was expanded somewhat when MISO implemented ELMP Phase 2 in May 2017.

Figure 12 shows all of the energy produced by online peaking resources, separated by:

- Whether they were scheduled in the day-ahead market or after the day-ahead market (i.e., in real time);
- Their start-up time; and
- Their minimum run-time.

Up until May 2017, the only online units eligible to set prices in ELMP are those that: a) can start in 10 minutes or less, b) have a minimum runtime of one hour or less, and c) are not scheduled in the day-ahead market. These units are shown to the far left of the figure (the column shaded in blue), which include only five percent of the peaking resources dispatched by MISO. The additional units that are eligible to set prices under Phase 2 of ELMP are shown by the columns shaded in light red. Although an improvement, the Phase 2 changes only allow 16 percent of MISO's peaking resources to set prices so the effects have been modest.

Figure 12: Eligibility for Online Peaking Resources in ELMP
January 2016 to December 2016



The IMM is recommending that additional units be eligible to set prices, which are shown in the figure by the columns shaded in light green. The IMM proposal would allow 92 percent of all of the peaking resources to set prices, which accounted for $17 million in RSG in 2016.

Evaluation of Offline ELMP Pricing

We have evaluated the offline pricing during transmission violations and operating reserve shortages, when ELMP sets prices based on the hypothetical commitment of an offline unit that MISO could theoretically utilize to address the shortage. This is only efficient when the offline resource is: a) feasible to address the shortage, and b) economic to commit. When units set prices that are either not feasible or not economic, the resulting prices will be inefficiently low.

When an offline unit is both feasible and economic, one would expect the unit will usually be started by MISO. When resources are not started, we infer that a) the operators did not believe the unit could be online in time to help resolve the shortage, and/or b) that the operator did not expect that the unit would be economic to operate for the remainder of its minimum runtime. Therefore, our evaluation quantifies how frequently the offline resources that set prices are actually started by MISO operators and how frequently they are actually economic in retrospect based on MISO's ex ante real-time prices. Table 5 below summarizes our results.

Table 5: Evaluation of Offline ELMP Price Setting
2016

	Economic*	Started	Economic & Started
Operating Reserve Shortages	20%	14%	**7%**
Transmission Shortages	33%	7%	**6%**

** Does not include units that were never started, which would increase the values to: 26% for OR shortages and 54% for Tx shortages.*

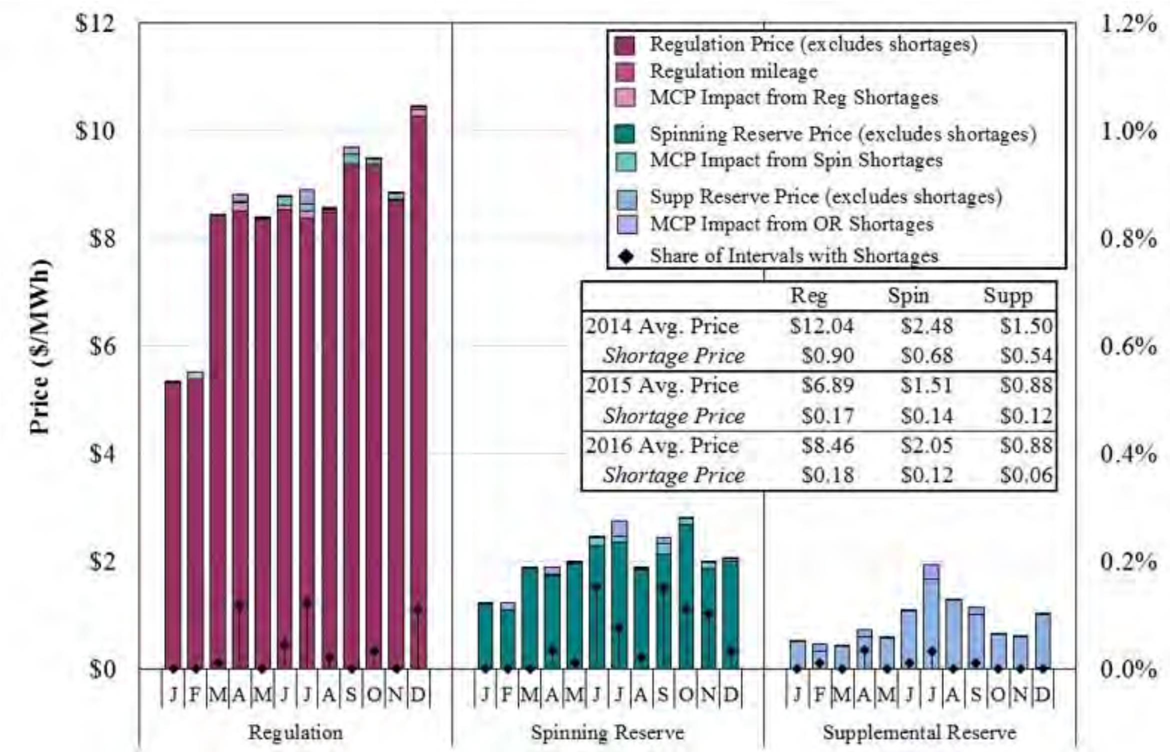
This table shows that the offline units that set prices during both operating reserve and transmission shortages are rarely economic and feasible (less than 7 percent of intervals). Based on these results, we conclude that ELMP's offline pricing component is not satisfying the economic principles outlined above and is leading prices to be less efficient during shortage conditions. As the Commission has recognized, efficient shortage pricing is essential for good market performance. Therefore, we recommend that MISO disable the offline pricing logic.

C. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2016. Since their inception in 2009, jointly-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions.

For each product, Figure 13 shows monthly average real-time prices, the contribution of shortage pricing to each product's price in 2016, and the share of intervals in shortage. MISO's demand curves specify the value of all of its reserve products.[15] When the market is short of one or more of its reserve products, the demand curve for the product will set the price and also be included in the prices of higher-valued reserves and energy through the co-optimized market clearing.

Figure 13: Real-Time ASM Prices and Shortage Frequency
2016



	Reg	Spin	Supp
2014 Avg. Price	$12.04	$2.48	$1.50
Shortage Price	$0.90	$0.68	$0.54
2015 Avg. Price	$6.89	$1.51	$0.88
Shortage Price	$0.17	$0.14	$0.12
2016 Avg. Price	$8.46	$2.05	$0.88
Shortage Price	$0.18	$0.12	$0.06

The supplemental reserve prices are for the market-wide operating reserve requirement (the only requirement supplemental reserves can satisfy). Spinning reserves can satisfy the operating reserve requirements, so the spinning reserve price will include a component for the operating reserve shortages. In other words, operating reserves shortages will be included in the price of higher-value reserves and energy. Likewise, regulation prices will include components associated with both spinning reserve and operating reserve shortages.

Monthly average clearing prices for regulating reserves and spinning resources rose slightly in 2016, but remain reasonable. The price for supplemental reserves remained virtually unchanged from 2015.

15 The demand curve for regulation, which is indexed to natural gas prices, averaged $112.01 per MWh in 2016. The spinning reserve penalty price was unchanged at $65 per MWh (for shortages < 10% of the reserve requirement) and $98 per MWh (for shortages > 10%). MISO introduced a new Operating Reserve Demand Curve in May 2013 that prices the first four percent of a total operating reserve shortage at $200 per MWh. More significant shortages are priced from $1,100 to $3,400 per MWh, depending on their severity.

D. Evaluation of Shortage Pricing in MISO

Virtually all shortages in any RTO are shortages of operating reserves (i.e., RTOs will hold less reserves than required rather than not serving the energy demand). When an RTO is short of its required operating reserves, the value of the foregone reserves should set the price for the reserves and be embedded in all higher-valued products, including energy. This value is established in the operating reserve demand curve (ORDC) for each reserve product. Therefore, efficient shortage pricing requires properly-valued reserve demand curves. Efficient shortage prices play a key role in establishing economic signals for new investment, facilitating optimal interchange between markets, and balancing the value of holding reserves subject to the cost of violating transmission constraints. An efficient RDC should abide by three principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all significant supply-side contingencies, including the risk of multiple contingencies occurring simultaneously; and
- Have no discontinuities that can lead to excessively volatile outcomes.

The marginal reliability value of reserves at any shortage level is equal to the expected value of the load that may not be served. This is equal to the following product at each reserve level:

Net value of lost load ("VOLL") * the probability of losing load.

MISO's current ORDC is not consistent with this valuation because:

- Only a small portion of it is based on the probability of losing load – over 90 percent of the current ORDC is set by administrative overrides of $200 and $1,100 that do not track the marginal reliability value of operating reserves; and
- MISO's current VOLL of $3,500 is understated.

Figure 14 shows the current ORDC and a curve that illustrates the IMM's proposed economic ORDC. Small shortages of less than 4 percent are priced at the lowest step of $200, but as reserve levels fall (and shortages increase) the current ORDC will price at $1,100, even though the probability of losing load is increasing. This single step to $2000 is intended to be consistent with FERC's Offer Cap rule.[16]

In comparison, the IMM's economic ORDC reflects the expected value of lost load, which we illustrate in Figure 14 based on an assumed VOLL of $12,000 per MWh. We estimated the probability of losing load using a Monte Carlo simulation.[17] The figure also shows that almost all shortages have been modest and priced in the green range shown on the figure.

16 "Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,"FERC RM16-5-000, Order No. 831, issued November 17, 2016.

17 The simulation estimated the conditional probabilities across 10,000 iterations, which is described in Section V.F of the Analytic Appendix.

Figure 14: Comparison of IMM Economic RDC to Current ORDC

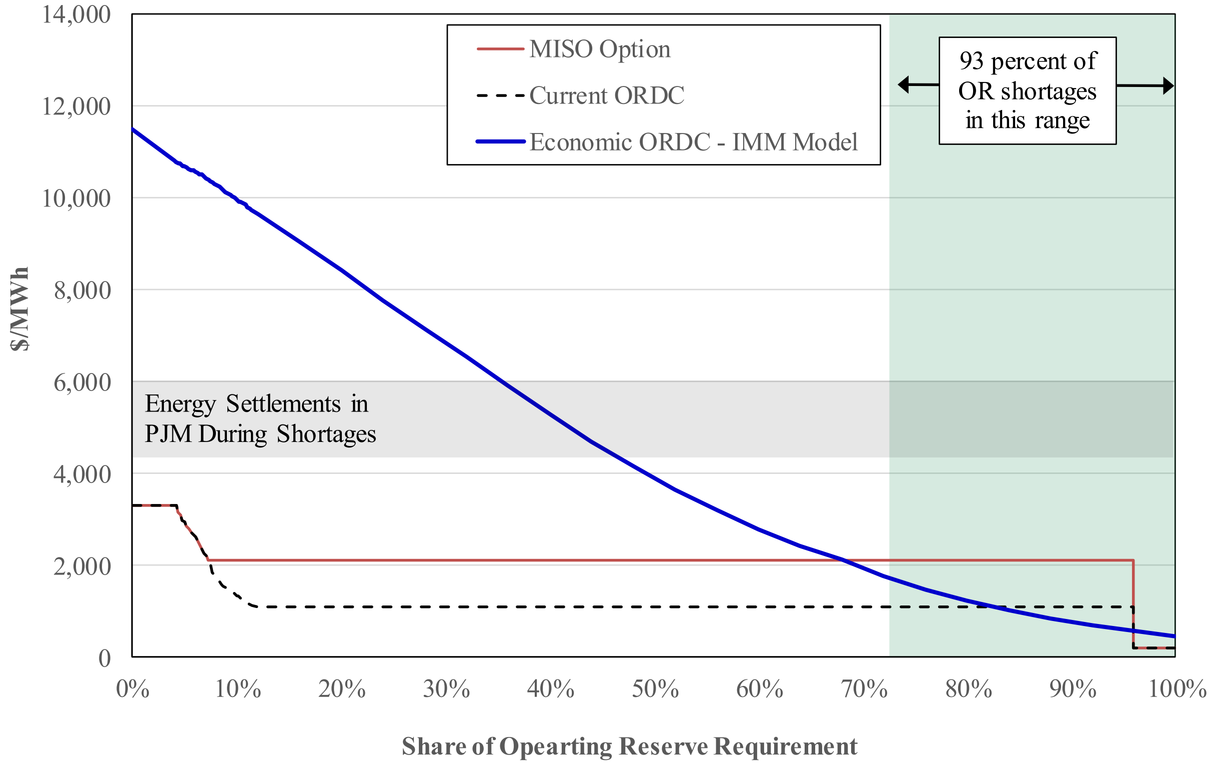


Figure 14 shows that the current curve will set inefficiently high shortage prices under some conditions and inefficiently low shortage prices under others. The sharp increase in the curve at 96 percent of MISO's reserve requirement leads to excessive price volatility at low shortage levels. An economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. This will result in more efficient reserve and energy prices during shortages, which will improve MISO's short-term economic signals to improve generator performance, day-ahead load scheduling, and import/export scheduling. It will also improve MISO's long-term investment signals.

E. Settlement and Uplift Costs

Uplift costs are very important because they are costs that are difficult for customers to hedge, and they generally reveal areas where the market prices do not fully capture all of the system's requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments in real time to ensure resources cover their as-offered costs and, therefore, have incentives to be available and flexible:

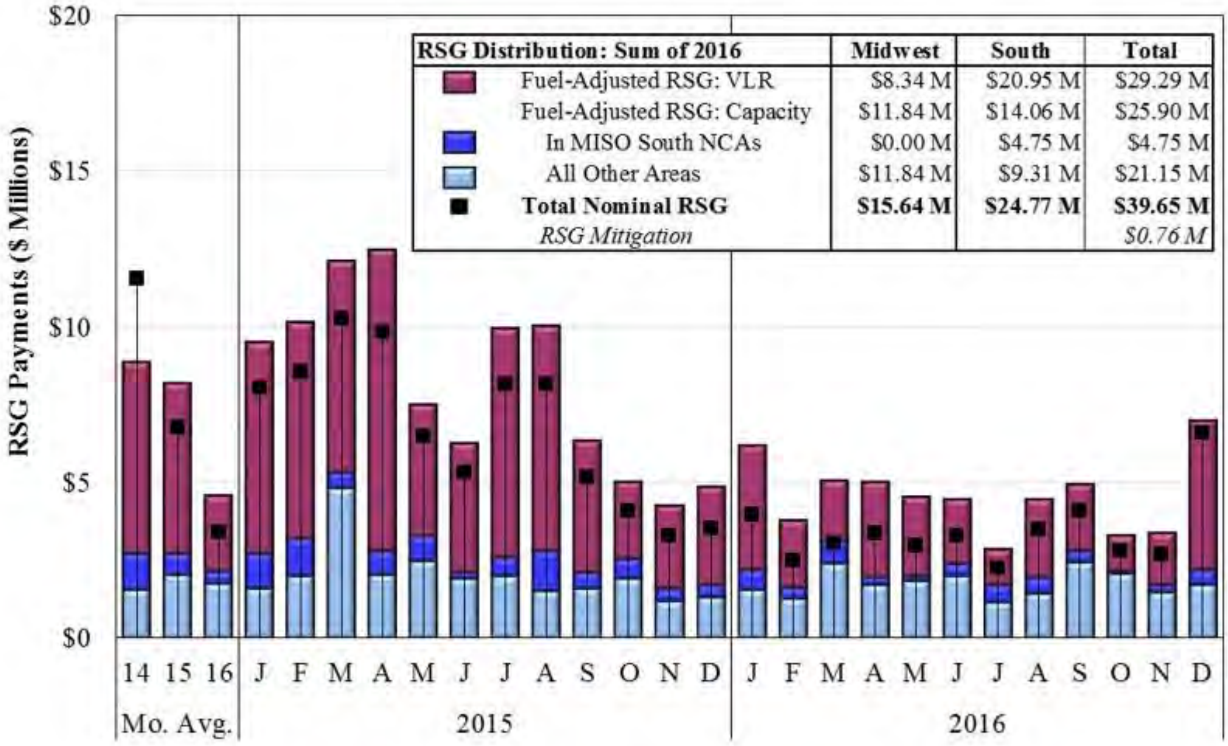
- RSG payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- Price Volatility Make Whole Payments ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Resources committed after the day-ahead market receive a “real-time” RSG payment to ensure they recover their as-offered costs. The real-time RSG costs are recovered via charges to participant actions that cause the costs, and the residual is charged to load. This allocation generates efficient incentives for participants, and FERC proposed that other RTOs adopt a comparable cost allocation method in a recent Notice of Proposed Rulemaking (NOPR).[18]

Day-Ahead and Real-Time RSG Costs

Figure 15 and Figure 16 show monthly day-ahead and real-time RSG payments, respectively. Most RSG payments for Voltage and Local Reliability (VLR) are made in the day-ahead market because most VLR commitments are made before or during the day-ahead market. Because fuel prices have considerable influence over suppliers’ production costs, the figures show RSG payments in both nominal and fuel-adjusted terms.[19] The maroon bars show the RSG paid to units started before the day-ahead for VLR, while the blue bars show the amounts that we determined were paid to units likely commited for VLR by the day-ahead model (but not designated as VLR).

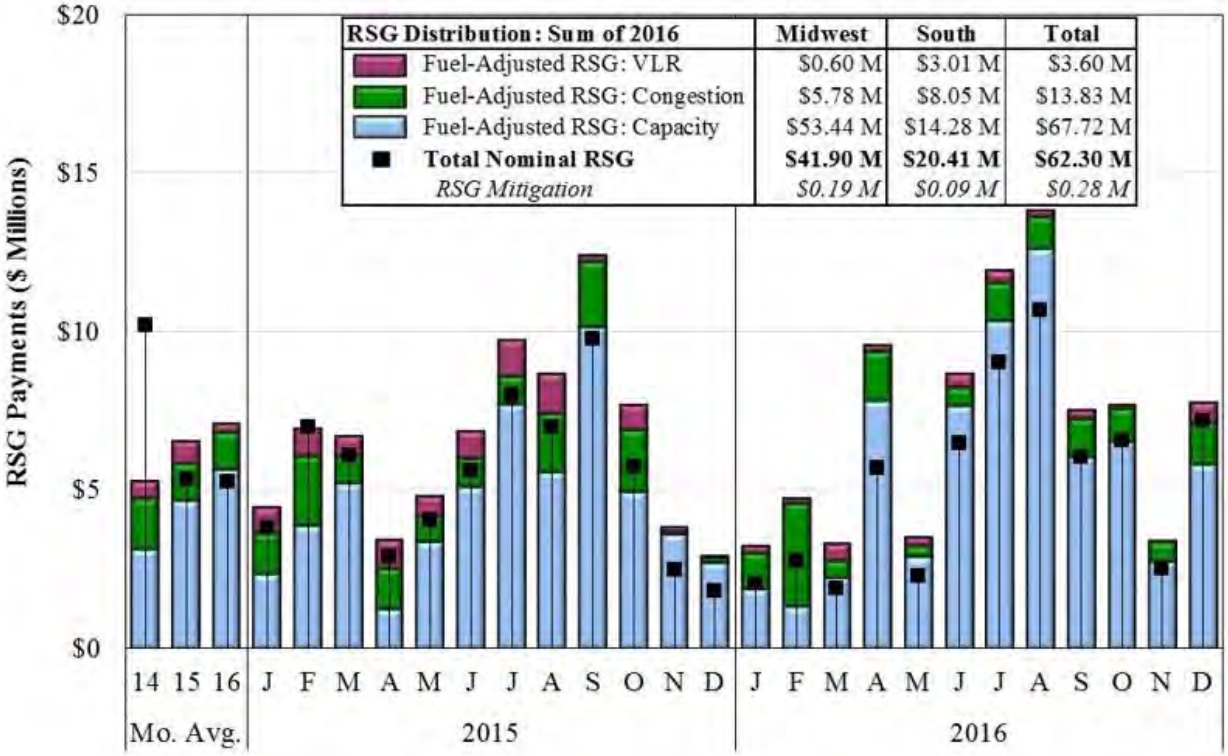
Figure 15: Day-Ahead RSG Payments
2015–2016



18 “Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators,” FERC RM17-2-000, issued January 19, 2017.

19 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are, therefore, greatest for periods when fuel prices were highest and vice versa.

Figure 16: Real-Time RSG Payments
2015–2016



RSG Distribution: Sum of 2016	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$0.60 M	$3.01 M	$3.60 M
Fuel-Adjusted RSG: Congestion	$5.78 M	$8.05 M	$13.83 M
Fuel-Adjusted RSG: Capacity	$53.44 M	$14.28 M	$67.72 M
Total Nominal RSG	**$41.90 M**	**$20.41 M**	**$62.30 M**
RSG Mitigation	*$0.19 M*	*$0.09 M*	*$0.28 M*

Nominal day-ahead RSG costs decreased by almost 50 percent to $3.4 million per month in 2016. Fuel-adjusted day-ahead RSG costs fell to comparable amounts, indicating that most of the cost reductions were due to better utilization of the transmission system and improvements in the process of committing resources to satisfy VLR requirements.

Additionally, MISO completed construction of several local projects in the Southern load pockets that reduced the need for some VLR commitments. Nonetheless, if one includes the RSG amounts likely caused by the VLR requirements in the day-ahead market, nearly 60 percent of day-ahead RSG payments were were caused by VLR needs in the South. To achieve further reductions, we have recommended that MISO improve its modeling of the VLR requirements in the day-ahead market, and MISO is pursuing approaches to address this recommendation.

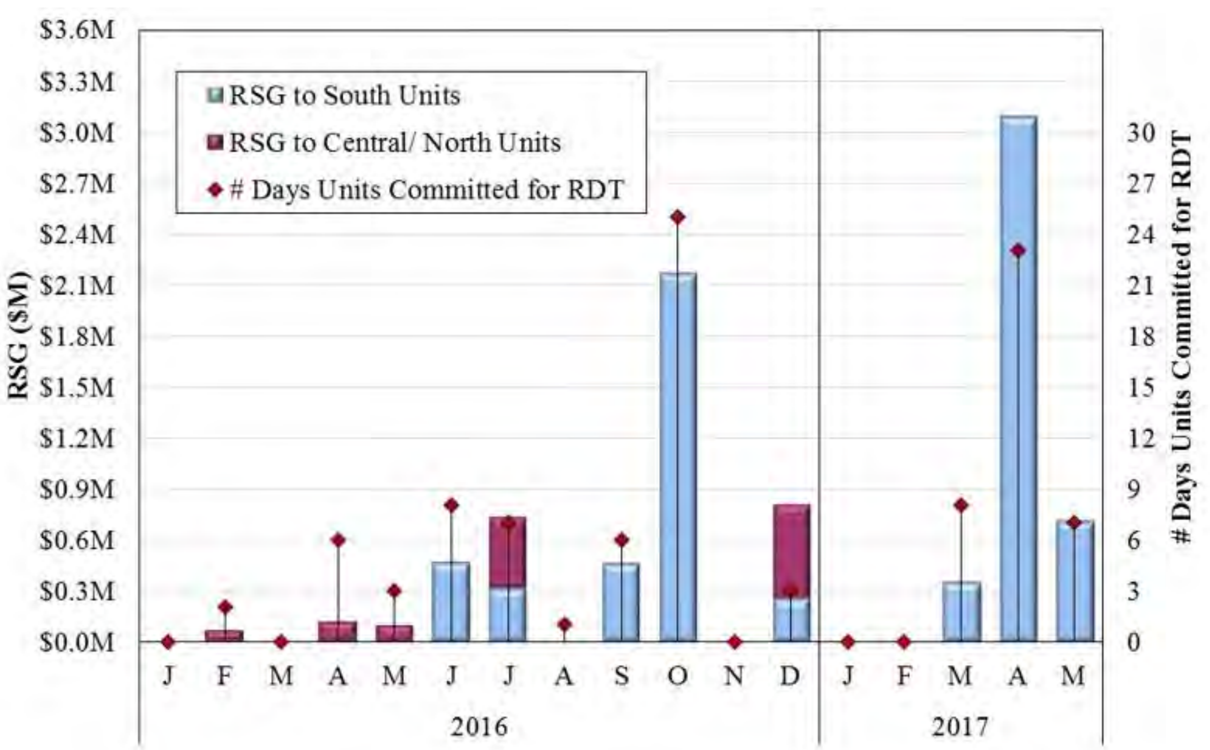
Figure 16 shows that nominal real-time RSG payments fell slightly (1.6 percent) from 2015, primarily because of lower fuel prices. Adjusting for changes in fuel prices, real-time RSG actually increased by nine percent in 2016. This increase occurred in April and in the summer months when hotter summer conditions resulted in increased use of peaking resources. Despite implementation of ELMP in 2015, most peaking resources utilized by MISO were not eligible to set energy prices, so they required RSG payments to cover their as-offered costs. MISO expanded eligibility modestly in May 2017, but we are recommending expanding the eligibility further, which will lower real-time RSG (see Section V.B for a more detailed discussion).

RSG Incurred to Satisfy Regional Capacity (Reserve) Needs

We have identified a substantial number of commitments and associated RSG made in MISO Midwest or MISO South to satisfy regional capacity needs when the Regional Dispatch Transfer (RDT) constraint is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region. These commitments are made outside of the market because MISO's markets do not include subregional capacity requirements.

In more recent months, particularly during periods of high generator outages in MISO South, MISO has incurred significant RSG for these types of commitments, and the costs of the commitments are largely spread across the entire MISO footprint. Figure 17 below illustrates the total RSG that MISO has incurred for these commitments since June 2016 and in which region (Midwest or South) the commitments were located. The maroon segment of the bars shows RSG payments to resources in the Midwest, and the blue bar segments indicate the resources that were turned on in the South region.

Figure 17: RSG Incurred to Satisfy Regional Capacity (Reserve) Needs

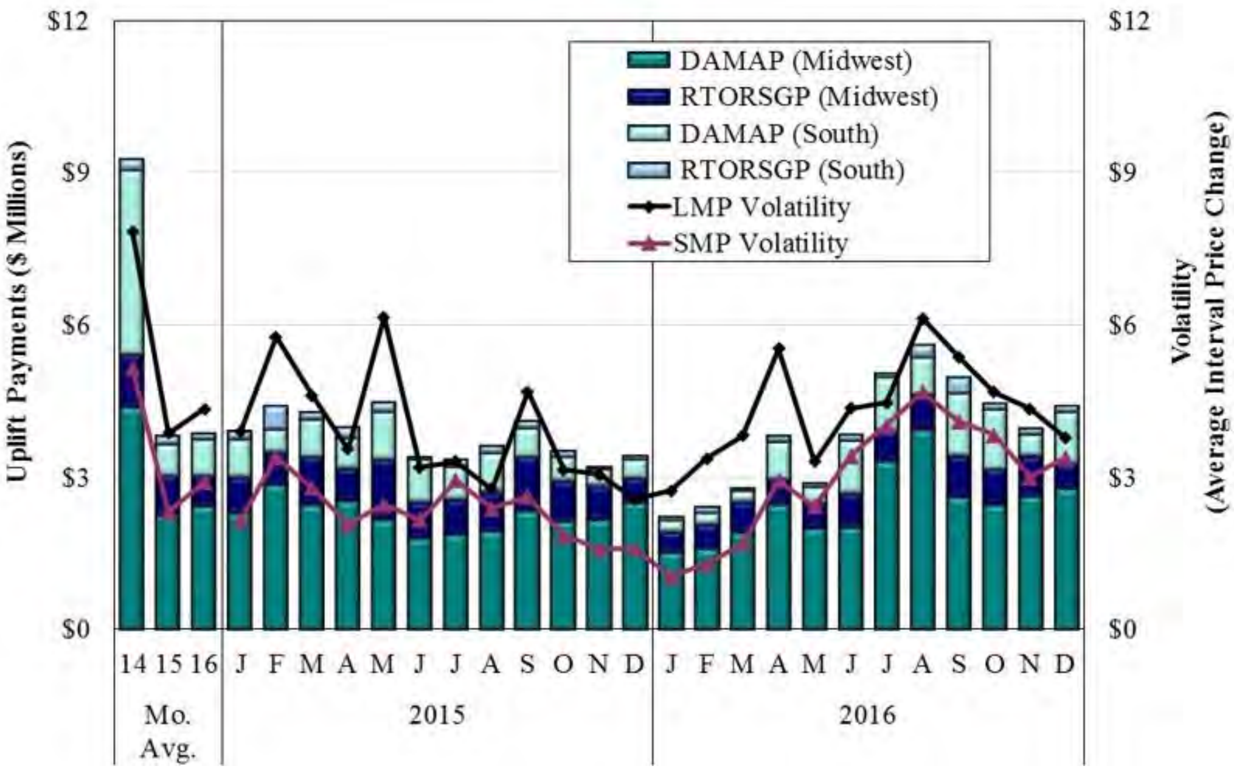


Since June 2016, MISO has incurred $9 million in RSG for subregional capacity commitments. Of this more than half was incurred in October 2016 and April 2017 when MISO South experienced very high generation outage rates. We are recommending that MISO establish subregional reserve requirements and regional cost allocation to allow its markets to satify and price local capacity requirements that are being satisfied currently through out-of-market commitment and reflected only in RSG costs. This could likely be addressed by the same product that MISO is developing to address the reserve needs in the VLR areas.

Price Volatility Make-Whole Payments

PVMWPs address the concerns that resources that respond flexibly to volatile five-minute price signals can be harmed by doing so because their settlement is based on the hourly average price. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and follow dispatch instructions. These payments come in two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP). DAMAP payments are made when generators produce output at a level that is below their day-ahead schedule and the level that is economic given the hourly settlement price and their offer prices. RTORSGP payments are made when a unit operates above the level that would be economic given the hourly energy price. Figure 18 shows the monthly totals for the two components of PVMWP, along with measures of price volatility at the system level (System Marginal Price, or SMP, volatility) and at the locations where units are receiving the payments (LMP volatility).

Figure 18: Price Volatility Make-Whole Payments
2015–2016

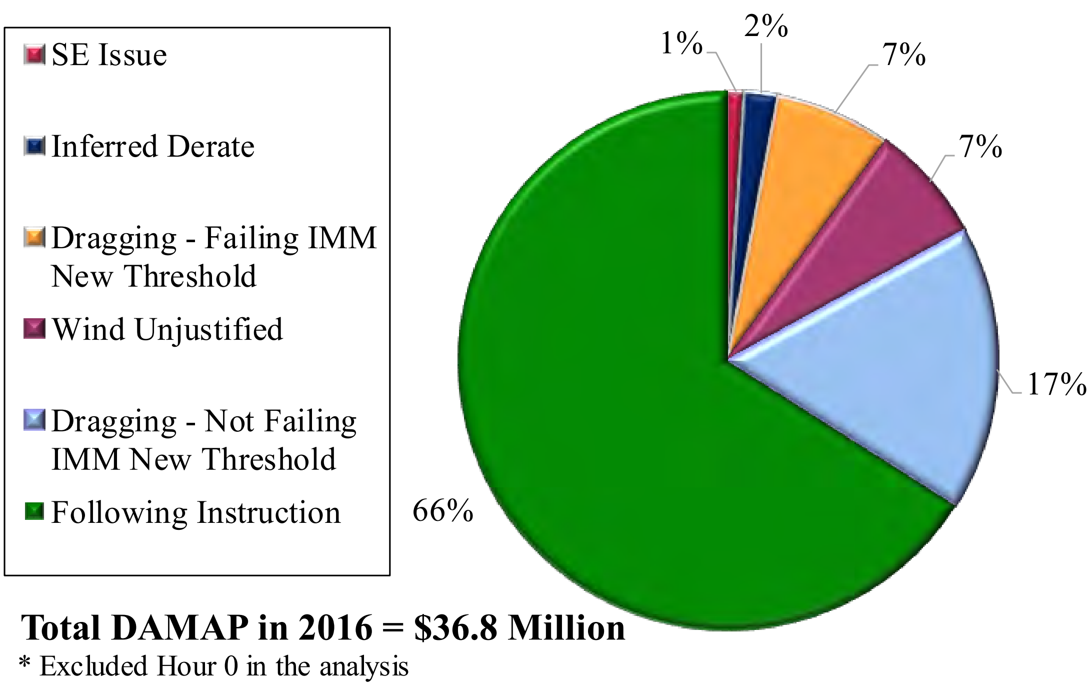


The figure shows that the PVMWP levels in 2016 were generally correlated with price volatility at the recipients' locations. Total PVMWP values rose 1.6 percent over the prior year as price volatility at the resources' locations increased by two percent. DAMAP accounted for all of the increase, as RTORSGP fell slightly from 2015 levels.

Although PVMWPs play an important role in MISO's market, we continue to be concerned that a large share of the DAMAP is paid to units running at uneconomic output levels because they are not following dispatch instructions, or because State Estimator model errors cause MISO to issue dispatch instructions that are less than optimal at some locations. To evaluate this concern, Figure 19 shows the total DAMAP paid in 2016, broken out into the follosing categories:

- Resources following their dispatch instructions;
- Resources deviating from MISO's dispatch instructions by less than the IMM's proposed deviation thresholds;
- Resources deviating from MISO's dispatch instructions by more than the IMM's proposed deviation thresholds;
- Resources not following dispatch instructions and effectively derated as a result;
- Resources appearing to deviate due to State Estimator model errors; and
- Wind resources that were receiving unjustified DAMAP because of forecast errors.

Figure 19: Causes of DAMAP
2016



Almost three million dollars of the DAMAP were unjustified payments to wind resources that over-forecasted their output. These resources should not be eligible for DAMAP payments, but they remain eligible because of an error in the MISO tariff.[20]

Figure 19 also shows that more than one quarter of the DAMAP was paid to resources that are not fully following MISO's dispatch instructions. In fact, while DAMAP does provide an incentive to be flexible, it also holds generators harmless for poor performance. In other words, it allows generators to avoid the economic consequences of poor performance. Further, we've identified a number of gaming strategies participants can employ to acquire unjustified payments. To address these issues, we are recommending that MISO reform the calculation of the DAMAP and RTORSGP to substantially reduce or eliminate the payments that are due to poor dispatch performance. Additionally, our other recommendations in this report that address generator deviations should reduce the unjustified DAMAP.

Five-Minute Settlement

MISO produces new dispatch signals and prices every five minutes but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signals and the hourly prices that subsequently create incentives for generators to not follow the dispatch signal or to be inflexible. To address these inconsistencies, MISO introduced the PVMWPs described above.

The PVMWPs have been effective at eliciting additional flexibility from MISO's resources. However, it is a poor substitute for a true five-minute settlement where each generator, importer, or exporter would settle based on the actual value of energy corresponding with its production or transactions in each five-minute interval. Our analysis for 2016 indicates that:

- Fossil-fuel-fired resources in 2016 received settlements that were $18 million less than they would have received were they to have settled based on five-minute prices and output.
- Less than a quarter of this lost value was paid to resources in the form of PVMWP.
- Less controllable resources, such as wind resources, are not as adversely impacted by the current hourly settlement because they generally cannot respond to the 5-minute price signals.

These results indicate that there are substantial discrepancies between the actual value of energy on a five-minute basis and settlements currently made on an hourly basis. The PVMWPs alone are not sufficient to address these discrepancies. Therefore, we have been recommending for years that MISO implement 5-minute settlements with generators, which will improve their incentives to be flexible and follow dispatch instructions. FERC supported this recommendation

20 The flaw is in the Schedule 27 payment formula, which is intended to cause resources dispatched at their EcoMax to be ineligible for DAMAP, but is specified incorrectly for wind resources.

in a Rule issued in 2016, which require that RTOs settle with market participants in the same time increments as they use to dispatch the system (i.e., five-minute settlements for MISO).[21] MISO has scheduled an implementation date of March 2018.

Generator Dispatch Performance

MISO sends energy dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. MISO assesses penalties for deviations from this instruction when deviations remain outside of an eight-percent tolerance band for four or more consecutive intervals within an hour.[22] The purpose of the tolerance band is to permit deviations to balance the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. However, MISO's criteria for identifying deviations are significantly more lenient than most other RTOs and contribute to poor performance by some suppliers with both economic and reliability implications. In addition to this settlement threshold, MISO's real-time operators employ a tool to identify resources that are responding poorly (or not at all) to MISO's dispatch. Resources identified by the tool should be contacted by MISO operators and, if warranted, placed off-control, which would result in the dispatch echoing the current output level of the resource.

Figure 20 shows the size and frequency of two types of net deviations:

- <u>Five-minute deviation</u> is the difference between MISO's dispatch instructions and the generators' responses in each interval.
- <u>60-minute deviation</u> is the effect over 60 minutes of generators not following MISO's dispatch instructions.

The methodology for calculating the net 60-minute deviation is described in more detail in Section V of the Analytical Appendix, but it is essentially the difference between energy the generator is actually producing and what it would be producing had it followed MISO's dispatch instructions over the prior 60 minutes. The figure shows these results by season and type of hour, including the typically steep ramping hours of 6, 7, and 8 a.m when the impact of deviations are most severe on both pricing and reliability.

This analysis shows that MISO's five-minute and 60-minute deviations are sizable in all seasons and types of hours. While the average five-minute deviations are slightly higher in the morning ramp-up hours than during other periods, the 60-minute deviations are much higher in these hours, averaging more than 400 MW. This continues to raises substantial concerns, averaging almost 20 percent of MISO's reserve requirements.

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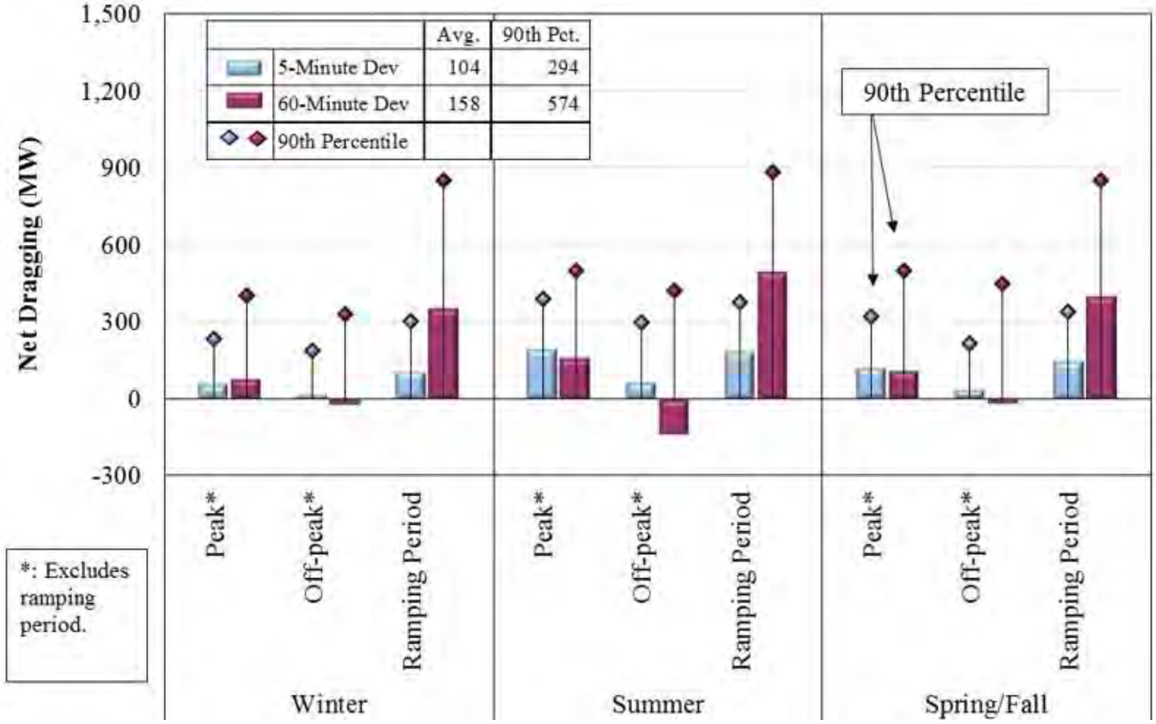
21 "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators," FERC RM15-24-000, NOPR issued September 17, 2015.

22 See Tariff Section 40.3.4.a.i. The tolerance band can be no less than 6 MW and no greater than 30 MW.

Figure 20: Average Five-Minute and Sixty-Minute Net Deviations
2016



The differences in the deviation metrics shown in this figure are important because the MISO operators will generally only see the five-minute deviations, and they do not have a tool to show the effective loss of capacity that accrues over time from generators that are performing poorly. Further, almost 50 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because it indicates that MISO is not perceiving this effective loss of capacity and, therefore, may not be making commitments that are justified economically or needed for reliability.

In 2016, MISO addressed State Estimator (SE) issues for some resources late in the year that caused some of the deviations. We have worked closely with MISO to identify SE issues as they arose, and we continue to recommend that MISO develop new tools to identify and address SE errors that are affecting the dispatch.

Finally, we monitor for "inferred derates," where the lack of response from a generator over time causes the generator to effectively be derated, which averaged 158 MW per hour in 2016 and was more than 1150 MW in some hours.[23] Because participants are obligated to report derates under the tariff, we have referred the most significant inferred derates to FERC enforcement. Additionally, such conduct can qualify as physical withholding when there is not physical cause

23 See Figure A49 in the Analytical Appendix for the detailed inferred derate results.

for the derating. We have identified such cases, and MISO has imposed physical withholding sanctions.

These findings indicate that it is very important that MISO improve its settlement rules and operating procedures for addressing poor generator performance. Therefore, we have recommended two changes.

First, MISO should improve the tolerance bands for uninstructed deviations (i.e., Deficient and Excessive Energy) to make them more effective at identifying units that are not following dispatch. In Section V of the Analytical Appendix, we discuss our proposed threshold, which is based on units' ramp rates and provides for more tolerance only in the ramping direction, so units that are moderately dragging or responding with a lag will not violate the threshold. Like the current thresholds, our proposed threshold would permit a resource to be unresponsive for four consecutive intervals to allow for configuration changes or changes in mill operations.[24]

Having established this threshold, we recommend that MISO apply it in a number of ways:

1. Apply the standard settlement rules pertaining to Deficient and Excessive Energy;
2. Remove eligibility for PVMWP for that hour;
3. Remove eligibility for the unit to provide ancillary services or the ramp product for that hour and the following hour; and
4. Remove the unit's headroom (available capacity) from the LAC model;

These changes will improve participants' incentives to perform well and follow MISO's dispatch instructions, while allowing MISO operators and its dispatch models to make better dispatch and commitment decisions.

Second, we recommend that MISO develop better tools and procedures for operators to use in real time to identify inferred derates and place such resources off control. This will allow its real-time market to dispatch energy from other resources that will respond to the dispatch signal.

F. New Operating Reserve Products

MISO has incurred substantial RSG in a limited number of areas to satisfy VLR requirements. These costs arise as MISO commits additional local resources to prepare the area to withstand both the largest potential contingency in the area as well as the second largest contingency. These requirements are attributable to the fact that some areas do not have resources that can start within 30 minutes to restore the lost reserves after the first contingency. In essence, MISO is committing resources to hold reserves on online resources.

24 Additional detail and a graphical illustration of the proposed threshold is provided in Section VI of the Analytical Appendix.

As described earlier, MISO is also committing resources to satisfy capacity requirements in the Midwest and South subregions of MISO to ensure that it can withstand the largest congingency in the subregion without exceeding the RDT limit. To address both of these needs, we recommend that MISO create a local 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets, rather than through out-of-market commitments that result in uplift.

For the subregions, defining such a product would likely alter the resource commitments in the day-ahead market to satisfy these needs at overall lower costs. It will also provide prices for these requirements, to include allowing the markets to price shortages when regional resources are insufficient to satisfy the full reserve requirement.

In the VLR areas, this would would provide market signals to build fast-starting units or other resources that can satisfy the VLR needs at a much lower cost (because they can satisfy the requirements while offline). Although this would not eliminate the need for VLR commitments, it would significantly reduce the amount of uplift within the MISO South load pockets of Amite South and WOTAB.

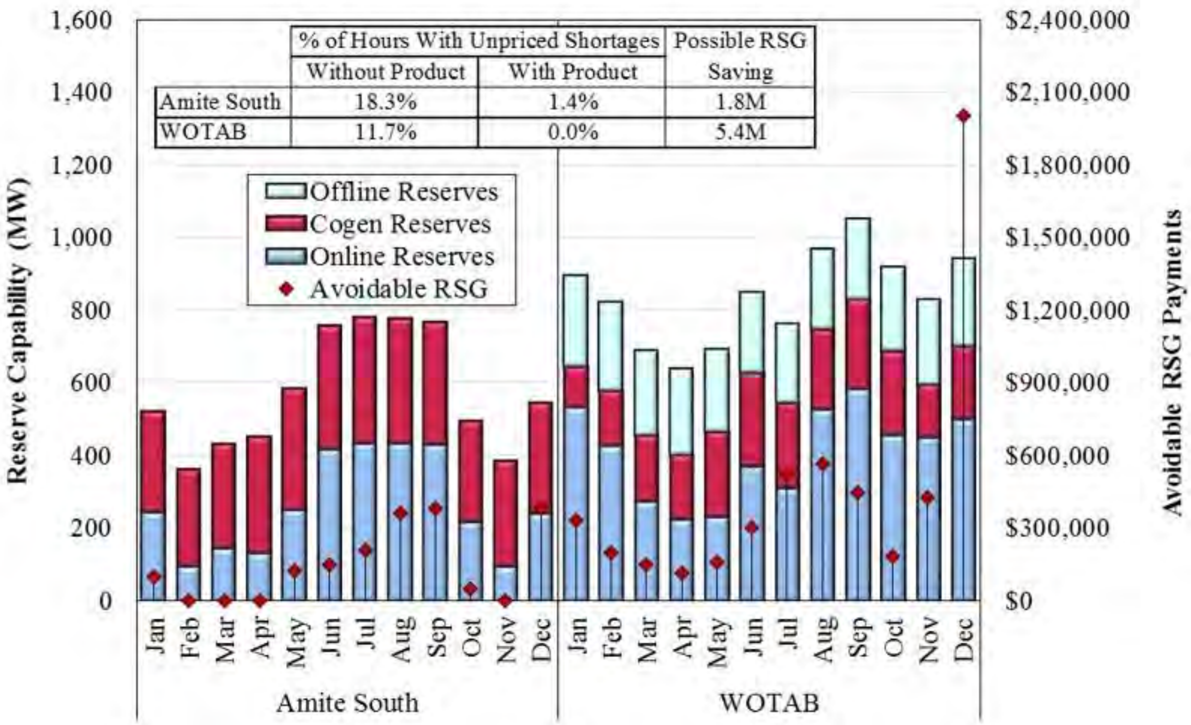
Additionally, defining such a product for the VLR areas may allow other resources that currently exist withing the load pockets to satisfy the VLR requirements. Figure 21 below quantifies all of the 30-minute reserve capability that is currently available to respond to a system contingency and the associated RSG savings from using those reserves to meet reliability objectives. We identified three main types of potential 30-minute reserve providers:

- Co-generation facilities (red bars),
- Combustion turbines that can start within 30 minutes (light blue bars), and
- Longer-start resources that must be online to participate (blue bars).

The figure shows the available reserves by load pocket. The left axis indicates the available capability in MW, and the right axis indicates the potential RSG that could have been avoided by procuring this through a reserve product, rather than committing generation to meet the same requirement with undispatched ranges (i.e., headroom) on online resources. The RSG savings is the sum of the RSG paid to the units de-committed in our simulation.

This analysis indicates that in 2016, MISO could have realized more than $7 million in RSG savings had a 30-minute reserve product been in place in the MISO South load pockets, and all of the resources we identified were capable of supplying it. While the two new categories of resources that we identified currently exist in the load pocket areas that could satisfy 30-minute reserve requirements, the resources do not have a means to sell this type of reserve product.

Figure 21: 30-Minute Reserve Capability Potential Savings
South Load Pockets, 2016



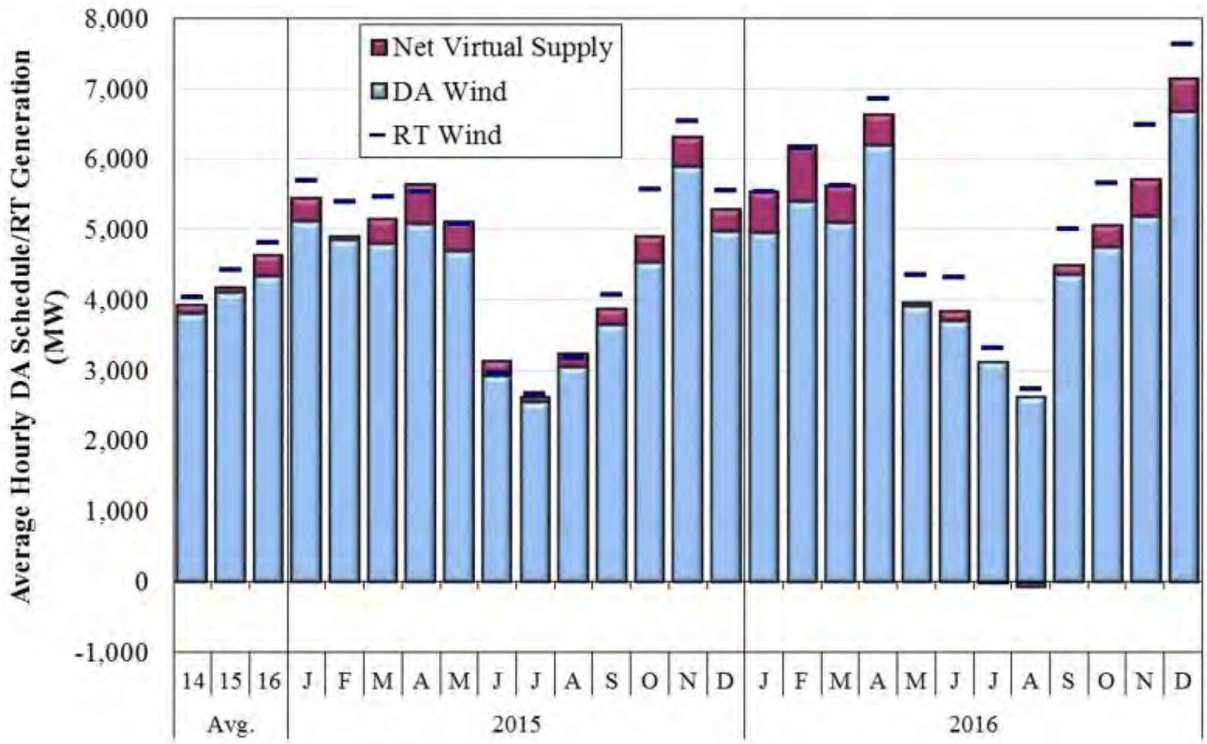
G. Wind Generation

In December 2015, Congress extended the investment tax credits (ITCs) and production tax credits (PTCs) for wind projects. Wind projects that began construction in 2015 or 2016 received either 30 percent ITCs or $23 per MWh in PTCs. Given the relatively high capacity factors for wind units in MISO, most new wind suppliers choose the PTC. Wind resources that were under construction by 2016 receive the full credit for 10 years, while the credit decreases 20 percent each year for units that begin construction from 2017 through 2019. These subsidies have resulted in an addition of 1.4 GW of wind capacity in 2016 and will continue to foster the growth of wind in the short-term. Installed wind capacity has grown to more than 16 GW. Although wind generation promises substantial environmental benefits, its output is intermittent and presents operational challenges. These challenges are amplified as wind's share of total output increases. Wind accounted for 10 percent of generation in 2016.

Day-Ahead and Real-Time Wind Generation

Figure 22 shows the average monthly amount of wind output scheduled in the day-ahead market compared to the actual real-time wind output. It also shows the amount of virtual supply scheduled on average at wind locations and the Minnesota hub, which is close to many of MISO's wind resources. The virtual supply tends to compensate for the fact that wind suppliers in aggregate do not schedule their full output in the day-ahead market.

Figure 22: Day-Ahead and Real-Time Wind Generation
2015–2016



Real-time wind generation in MISO increased 9 percent in 2016 to 4.8 GW per hour. MISO set several all-time wind records in 2016, the last of which was set in December at 13.7 GW. We expect this trend to continue as more wind resources are added to the system. The figure shows that wind output is substantially lower during summer months than during shoulder months, which reduces its reliability value to the system.

Figure 22 also shows that wind suppliers often schedule less output in the day-ahead market than their real-time output. This can be attributed to some of the suppliers' contracts and the financial risk related to being allocated RSG costs when day-ahead wind output is over-forecasted. Underscheduling can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. Underscheduling of wind averaged 472 MW per hour. The figure shows that virtual supply played a key role in arbitraging the scheduling inconsistency caused by the wind suppliers by offsetting almost two-thirds of the underscheduled wind.

As total wind capacity continues to grow, the operational challenges will grow related to output volatility and congestion that must be managed by MISO. Sharp reductions in output can lead to substantial price volatility and require MISO to make real-time commitments to replace lost output. MISO has been updating its processes and products to address these challenges, including the introduction of the ramp product in 2016. The concentration of the wind resources in the western areas of MISO's system has also created growing network congestion in some periods that can be difficult to manage. However, MISO's introduction of the Dispatchable Intermittent Resource (DIR) type in June 2011 has been essential in allowing MISO to manage this volatility. DIR participation by wind resources provides MISO much more timely control over its wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). The expansion of DIR has almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or over-generation conditions.

Wind Forecasting

Over the past year, we have identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output. The wind forecasts are important because MISO uses them to establish wind resources' economic maximum in the real-time energy market. Because wind resources offer at prices lower than any other resources, the forecasted output also typically matches the MISO dispatch instruction, absent congestion. Since an over-forecasted resource will produce less than the dispatch instruction, this will result in dispatch deviations. Figure 23 shows the monthly average quantity of the dispatch deviations from the wind resources (in the bars), as well as the average forecast error plotted as a line against the right y-axis in 2015 and 2016.

Figure 23: Generation Wind Over-Forecasting Levels
2015–2016

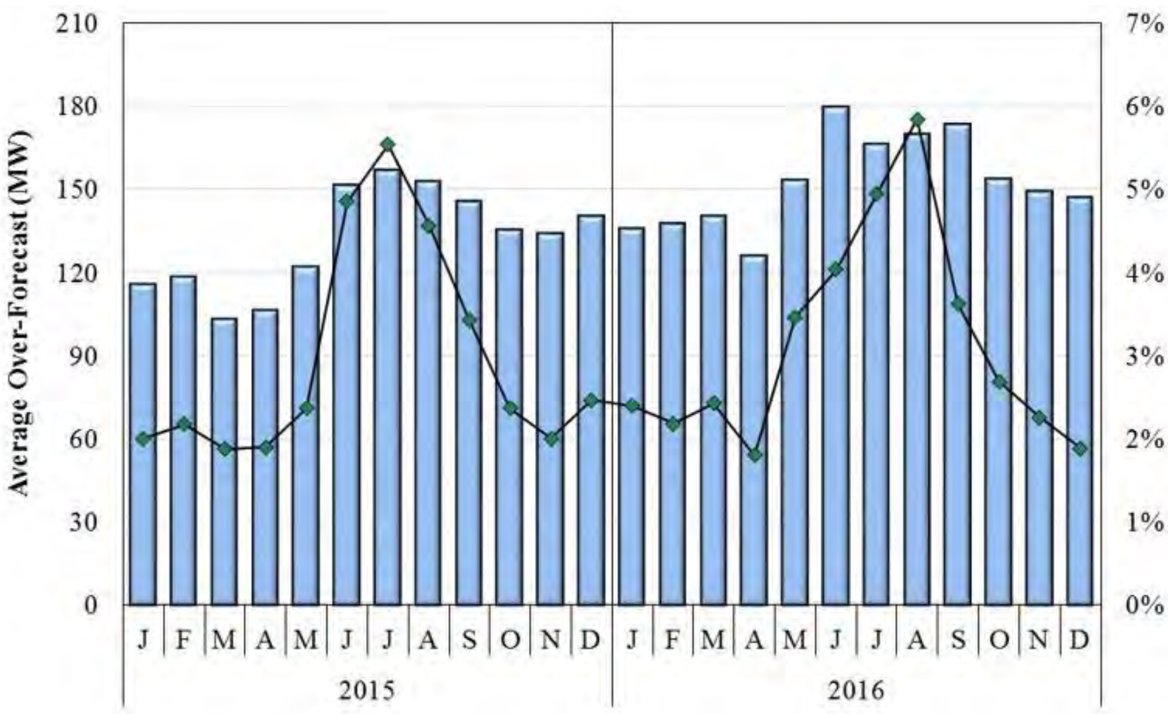


Figure 23 shows that wind resources in aggregate consistently over-forecast their output capability. The over-forecasting rate is much higher in the summer months even though the wind output tends to be lower in these months. We believe these patterns are consistent with incentives provided by the MISO market rules. We identified two primary factors that contribute to wind over-forecasting: DAMAP and uninstructed deviation settlements.

DAMAP Tariff Flaw. MISO's DAMAP settlements formula allows existing DIR wind resources to receive unintended DAMAP when they are dispatched at their economic maximum. Resources were only intended to receive DAMAP when they are dispatched below their economic maximum. However, the tariff was written in a manner that did not recognize that the economic maximum would be able to change every five minutes as it can for DIR wind units (it changes hourly for all other units), because it was written before the advent of DIR resources.

Biased Uninstructed Deviation Settlements. Wind resources face asymmetric costs for uninstructed deviations associated with forecast errors. One reason for this is that generators are paid the lower of their offer price or zero for excess energy. Due to PTCs, wind resources generally submit negative energy offers, so the penalty for excessive energy is much larger than for other resource types (the penalty is the difference between the LMP and their offer price). Conversely, wind units are only deficient when the resource's actual generating capability is less than its forecast, a situation that does not cause them to forego any profit margin.[25]

Aligning the excessive and deficient energy penalties (by reducing the explicit excessive energy penalty or increasing the costs of deficient energy) would help to balance the incentives and promote less-biased forecasts. MISO should also consider other approaches to promote unbiased wind resource forecasts, including adopting excess energy thresholds for wind resources that recognize the potential for congestion to arise if wind resources over-produce.[26] MISO could provide wind resources a "not-too-exceed" limit that would allow wind resources to exceed its dispatch instructions up to a reliable maximum level. This solution would maximize the economic value of these low-cost resources by allowing them to produce more than their forecast, while mitigating reliability concerns associated with wind output volatility.

Finally, we recommend that MISO review and validate wind forecasts in real time. This validation would allow MISO to replace participants' forecasts when they are consistently shown to be biased in the over-forecast direction.

25 In fact, wind resources will generally receive a DAMAP settlement that will provide this profit margin on the energy they are unable to produce.

26 ISO New England employs a similar approach.

VI. TRANSMISSION CONGESTION AND FTR MARKETS

To avoid overloading transmission constraints, MISO's markets manage flows over its network by altering the dispatch of its resources and establishing efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because transmission capability is limited – so higher-cost units must be dispatched in place of lower-cost units to avoid overloading a transmission facility. This generation re-dispatch or "out-of-merit" cost is reflected in the congestion component of MISO's locational prices.[27] The congestion component of the LMPs can vary substantially across the system, increasing LMPs in "congested" areas where increased generation would relieve the constraints. Conversely, congestion components lower LMPs in areas where generation increases the flows over the constraints.

These congestion-related price signals are valuable not only because they induce generation resources to produce at levels that efficiently manage network congestion, but also because they provide longer-term economic signals that facilitate efficient investment and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion in 2016

We separately calculate the value of real-time congestion by multiplying the flow over each constraint times the economic value of the constraint (i.e., the "shadow price"). This is a valuable metric, because it indicates the congestion that is actually occurring as MISO dispatches its system. Figure 24 shows the monthly real-time congestion values in 2015 and 2016.

The value of real-time congestion increased by four percent from last year to $1.4 billion. Natural gas prices decreased in 2016, which tends to reduce congestion costs because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Additionally, congestion was much lower in early 2016 because of mild winter weather. However, these factors were more than offset by:

- High congestion levels during the summer months. Real-time congestion rose 35 percent from last summer (to $464 million), which was due to high loads and key generation and transmission outages, particularly in the South.
- High network flows from wind resources in MISO and PJM contributed to the congestion in the Spring and Fall.
- Planned transmission outages (including outages for construction of Multi-Value Projects).

27 The marginal congestion component or "MCC" is one of three LMP components, which also includes a marginal energy component and a marginal loss component.

Figure 24: Value of Real-Time Congestion and Payments to FTRs
2015–2016

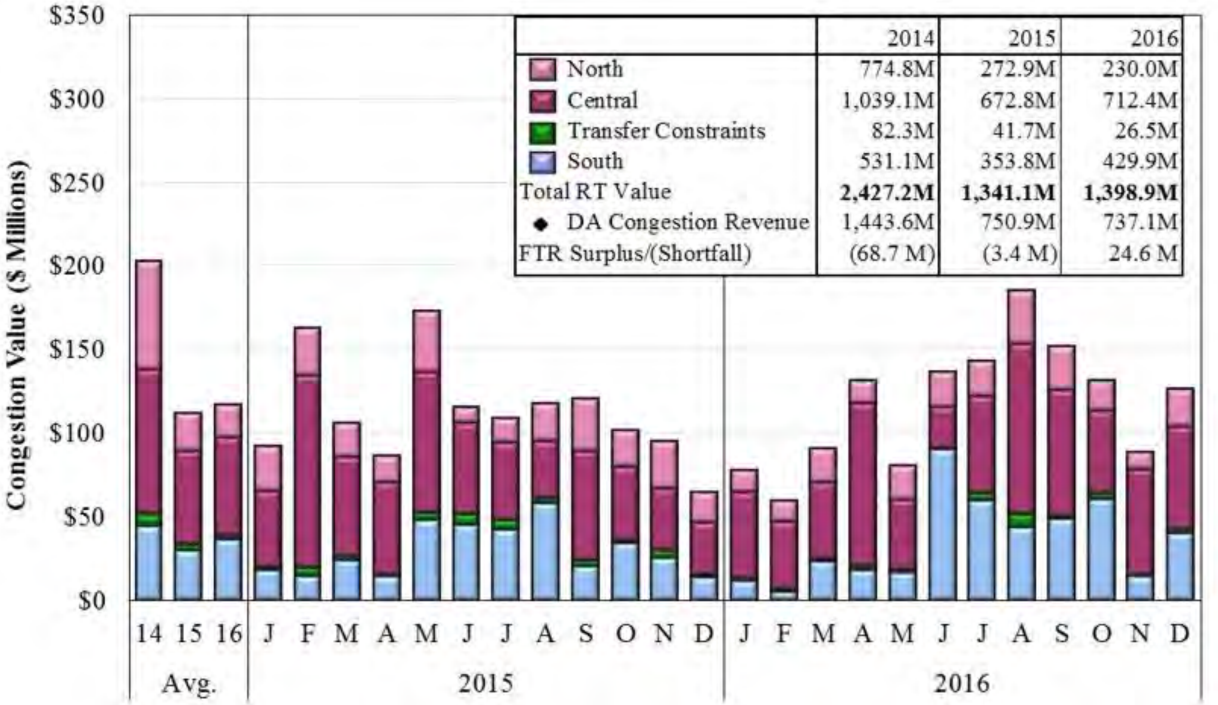


Figure 24 also shows that congestion on the transfer constraints fell significantly in 2016.[28] This was partly due to the settlement agreement with SPP and the Joint Parties approved in January 2016. This agreement allowed MISO to replace the Sub-Regional Power Balance Constraint (SRPBC), modeled with a 1,000 MW limit and Hurdle Rate of $9.57/MW (that reflected the potential transmission charges from SPP), with the RDT to constraint that allows directional transfers ranging from 2500 to 3000 MW. This has allowed MISO to capture substantial dispatch savings.[29] Congestion on the transfer constraints also fell because MISO also worked with TVA to improve TLR procedures and the day-ahead modeling of these constraints.

Although transmission congestion was only slightly higher in 2016, our evaluation of this congestion revealed issues that contributed to this increase. These issues are discussed later in this section, but include:

- Procedureal issues in defining and activating market-to-market constraints;
- Inefficient congestion on constraints affected by resources pseudo-tied to PJM; and
- Congestion caused by the lack of coordination of transmission and generation outages.

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28 "Transfer" constraints are those whose flows are predominately or entirely affected by transfers between the MISO North and South sub-regions. This includes the current RDT constraint (and prior SRPBC), as well as certain external constraints that are activated in MISO when a TLR is called (generally by TVA).

29 See our Quarterly reports for Winter 2015/2016 through Spring 2017.

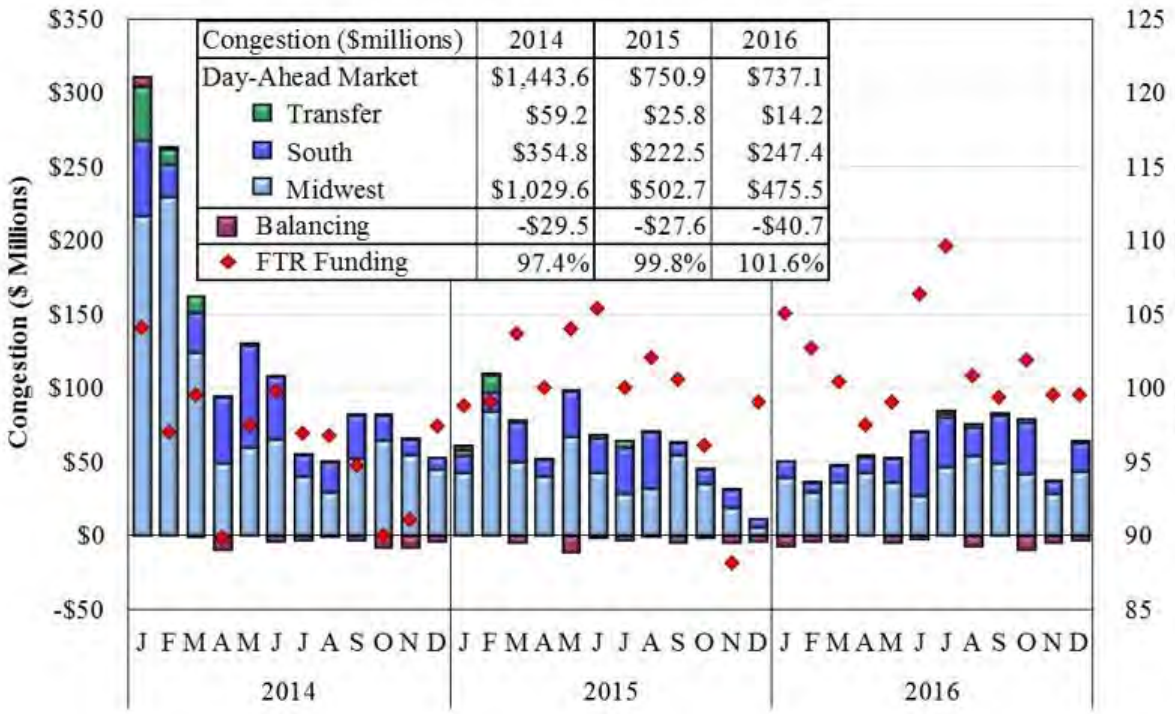
B. Day-Ahead Congestion Costs and FTR Funding in 2016

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the congestion component of the LMPs at locations where energy is scheduled to be produced and consumed.

The resulting congestion revenue is paid to holders of FTRs, which represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an instrument for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible (flows over the network sold as FTRs do not exceed limits in the day-ahead market), MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs – to pay them 100 percent of the FTR entitlements.

Figure 25 summarizes the day-ahead congestion by region (and between regions), as well as the balancing congestion incurred in real time and the FTR funding levels from 2014 to 2016.

Figure 25: Day-Ahead and Balancing Congestion and Payments to FTRs
2014–2016



Congestion ($millions)	2014	2015	2016
Day-Ahead Market	$1,443.6	$750.9	$737.1
Transfer	$59.2	$25.8	$14.2
South	$354.8	$222.5	$247.4
Midwest	$1,029.6	$502.7	$475.5
Balancing	-$29.5	-$27.6	-$40.7
FTR Funding	97.4%	99.8%	101.6%

Note: Funding Surplus or Shortfall may be more or less than the difference between day-ahead congestion and obligations to FTR Holders because it includes residual costs and revenues from the FTR auctions, such as the net settlements in the monthly FTR market.

Day-Ahead Congestion Costs

Day-ahead congestion costs fell two percent to $737.1 million in 2016. Much of the reduction in congestion occurred during February when day-ahead congestion was 60 percent lower than the prior year. The decline in 2016 was caused by lower gas prices, mild weather conditions early in the year, and reduced congestion on transfer constraints.

The congestion costs collected through the MISO markets are much less than the value of real-time congestion on the system, which totaled $1.4 billion in 2016. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network, as well as entitlements on the MISO system granted to JOA counterparties, including PJM, SPP, and TVA. For example, PJM does not pay for its power flows on MISO's market-to-market constraints up to PJM's entitlements.

Congestion on constraints in MISO South and the transfer constraints between the Midwest and South regions accounted for 35 percent of all day-ahead congestion. The MISO South and Midwest regions have diverse load patterns and mixes of generation. Differences in weather, load, generation and transmission availability, and regional gas prices affect the transmission congestion patterns within each region and between the regions over the transfer constraints.

In the Fall of 2016, generation outages in MISO South led to several operational challenges and increases in day-ahead congestion, as nearly 40 percent of the total generating capacity was on outage in October. Three-quarters of these outages were planned. An additional 3.4 GW of capacity was derated. The high level of outages in the South also led to flows primarily North-to-South after late September, a reversal in the typical pattern.

FTR Shortfalls

Congestion revenues exceeded FTR obligations by $24.6 million – a surplus of 1.6 percent – a slight increase in funding from 2015 when FTRs were underfunded by 0.2 percent. Nearly half of the surplus ($12 million) occurred in July, while several other months experienced slight shortfalls. Over- and underfunding is caused by discrepancies in the modeling of the annual and monthly auctions compared to the transmission constraints and outages that actually occur.

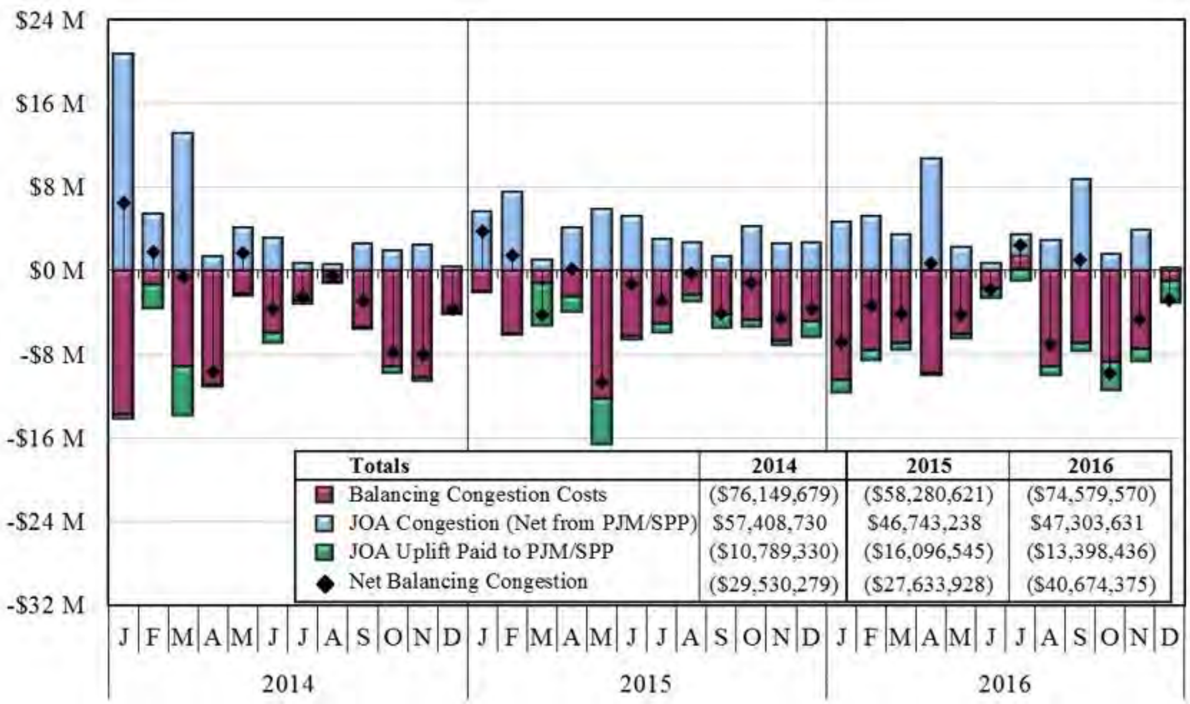
The most significant causes for underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. Underestimated loop flows also account for the some of the shortfalls, because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets. In 2016, these factors were more than offset by FTR surpluses produced on constraints whose capability were not fully sold in the FTR auctions.

Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) occurs when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, the costs of redispatching generation to reduce flows scheduled in the day-ahead market are negative balancing congestion. Positive balancing congestion occurs when real-time constraints bind at flows higher than scheduled in the day-ahead market.

Large amounts of negative balancing congestion revenue typically indicate real-time transmission outages, derates, or loop flow that was not anticipated in the day-ahead market. Net negative balancing congestion must be uplifted to MISO's customers. These costs are collected from all real-time loads and exports (on a pro-rata basis) so they do not directly impact FTR funding. While real-time forced outages and derates cannot be eliminated, persistent high levels of negative balancing congestion may indicate day-ahead modeling issues. Accordingly, RTOs should generally seek to minimize these shortfalls by achieving maximum consistency between the day-ahead and real-time market models. Figure 26 shows the monthly congestion costs incurred by MISO monthly over the past three years.

Figure 26: Balancing Congestion Costs
2014–2016



Totals	2014	2015	2016
Balancing Congestion Costs	($76,149,679)	($58,280,621)	($74,579,570)
JOA Congestion (Net from PJM/SPP)	$57,408,730	$46,743,238	$47,303,631
JOA Uplift Paid to PJM/SPP	($10,789,330)	($16,096,545)	($13,398,436)
Net Balancing Congestion	($29,530,279)	($27,633,928)	($40,674,375)

Balancing congestion costs increased 47 percent in 2016. Figure 26 shows that balancing congestion shortfalls totaled nearly $41 million (excluding Joint Operating Agreement, or JOA, uplift of $13.4 million) in 2016. JOA uplift payments are made to pay for market flows on coordinated market-to-market constraints. MISO had balancing congestion shortfalls in all but two months of the year. These levels of balancing congestion costs indicate that consistency between the day-ahead and real-time market models could be improved.

Coordinating Outages that Cause Congestion

Generators take planned outages to conduct periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various system. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces the transmission capability of the system. MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages.

Participants tend to consolidate planned outages in shoulder months, assuming that the opportunity costs of taking outages is then lower because load is mild and prices are relatively low. However, this is not always true. Different participants may schedule multiple generation outages in a constrained area or transmission outages into the area at the same time without knowing what others are doing. Absent a reliability concern, MISO does have the tariff authority to deny or postpone a planned outage, even when it will likely have substantial economic effects. Figure 27 provides a high-level evaluation of how uncoordinated planned outages can affect congestion. It shows the real-time congestion value incurred from January 2016 through May 2017. We identify the portion of the congestion on constraints substantially affected by two or more planned outages (affecting at least 10 percent of the constraints' flows).

Figure 27: Congestion Affected by Multiple Planned Generation Outages
January 2016 to May 2017

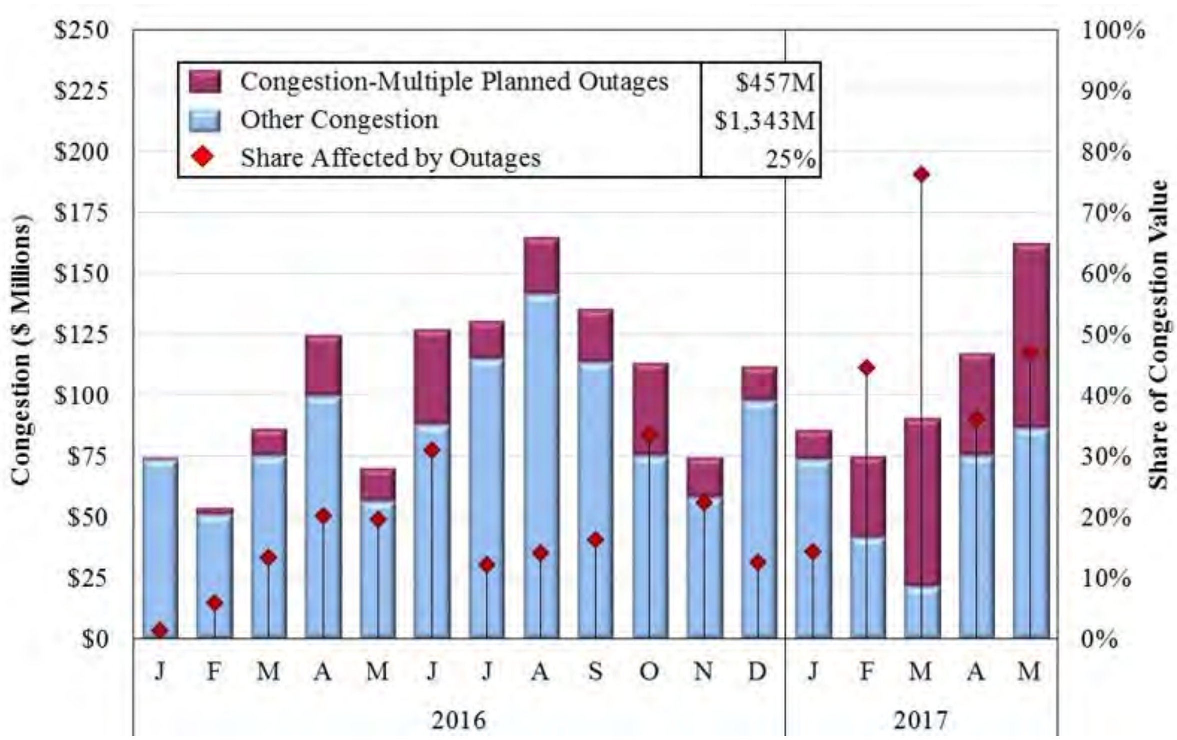


Figure 27 shows that 25 percent of the total real-time congestion – $457 million – was attributable to multiple planned generation outages. In the majority of the months that we analyzed, planned outages led to more than ten percent of the total congestion, and grew to more than 70 percent of all congestion in March 2017. These totals may understate the effects of planned generation outages on MISO's congestion, because we do not include the effects of transmission outages that are scheduled at the same time as planned generation outages.

Given how costly outages can be, we recommend that MISO seek expanded authority to coordinate planned generation and transmission outages in order to reduce unnecessary economic costs.

C. FTR Market Performance

A Financial Transmission Right (FTR) represents a forward purchase of day-ahead congestion. Because transmission customers pay for the embedded costs of the transmission system, they are entitled to its economic property rights. This is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers based on their network load and resources. ARRs give customers the right to receive the FTR auction revenues from the sale of the FTRs or to convert their ARRs into FTRs directly in order to receive day-ahead congestion revenues.

FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion, resulting in low FTR profits for the buyers (day-ahead congestion payments minus the FTR price). It is important to recognize, however, that even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may cause actual congestion to be much higher or much lower than FTR auction values. MISO currently runs:

- An annual auction (from June to May) that includes seasonal and peak/offpeak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA), that yields monthly and seasonal peak/offpeak awards. The MPMA facilitates FTR trading for future periods in the planning year.

FTR Market Profitability

Figure 28 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Figure 28 shows that FTRs issued through the annual FTR auction were substantially unprofitable in the first two quarters of 2016 because there was less congestion during the first two quarters than anticipated by the FTR market. However, they were profitable during the summer and fall quarters. The day-ahead congestion value was $175 million less than the annual auction valuation during the 2015-16 auction year (June 2015-May 2016). These FTR losses are partly the result of market participants "self-scheduling" ARRs (converting the ARRs to FTRs), which is equivalent to bidding to buy the FTR at any price (or refusing to sell at any price).

Figure 28: FTR Profits and Profitability
2015–2016

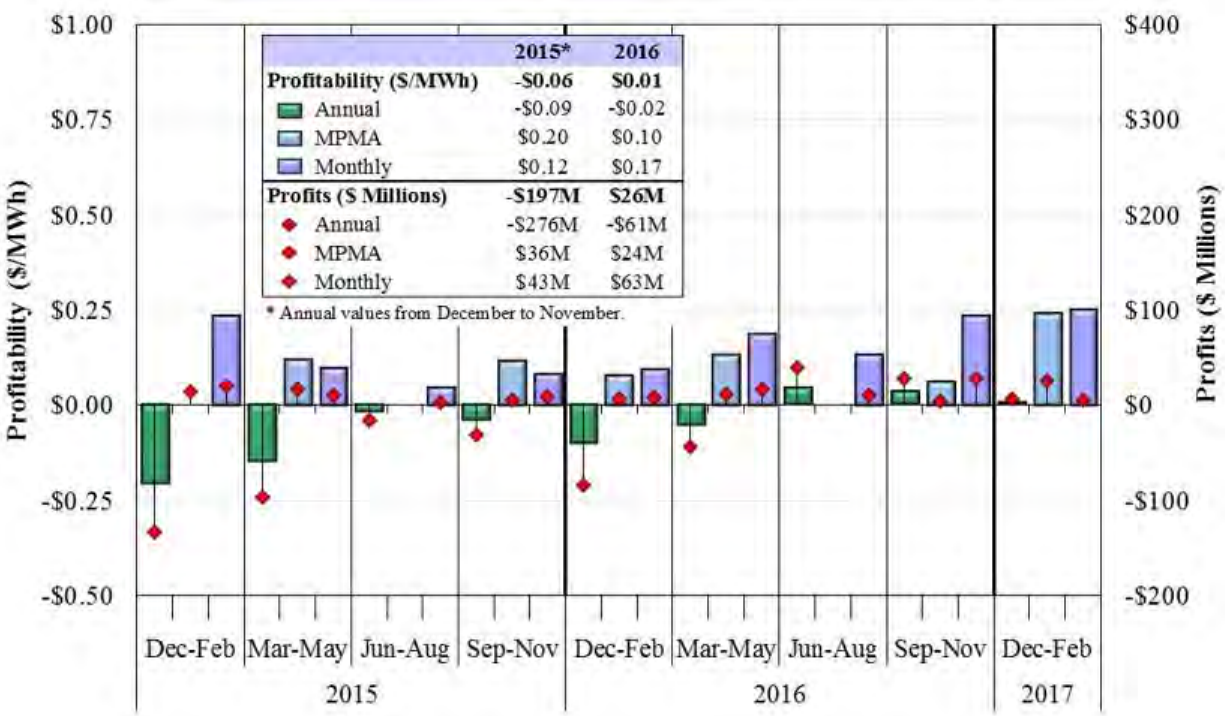


Figure 28 also shows that the FTRs purchased in the MPMA and prompt month have generally been profitable. These markets tend to produce prices that are more in line with anticipated congestion than the annual auction. Additionally, because the MPMA and prompt month occur much closer to the operating timeframe, better information is available to forecast congestion.

Multi-Period Monthly FTR Auction

In the MPMA FTR auction, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on an constraint.[30]

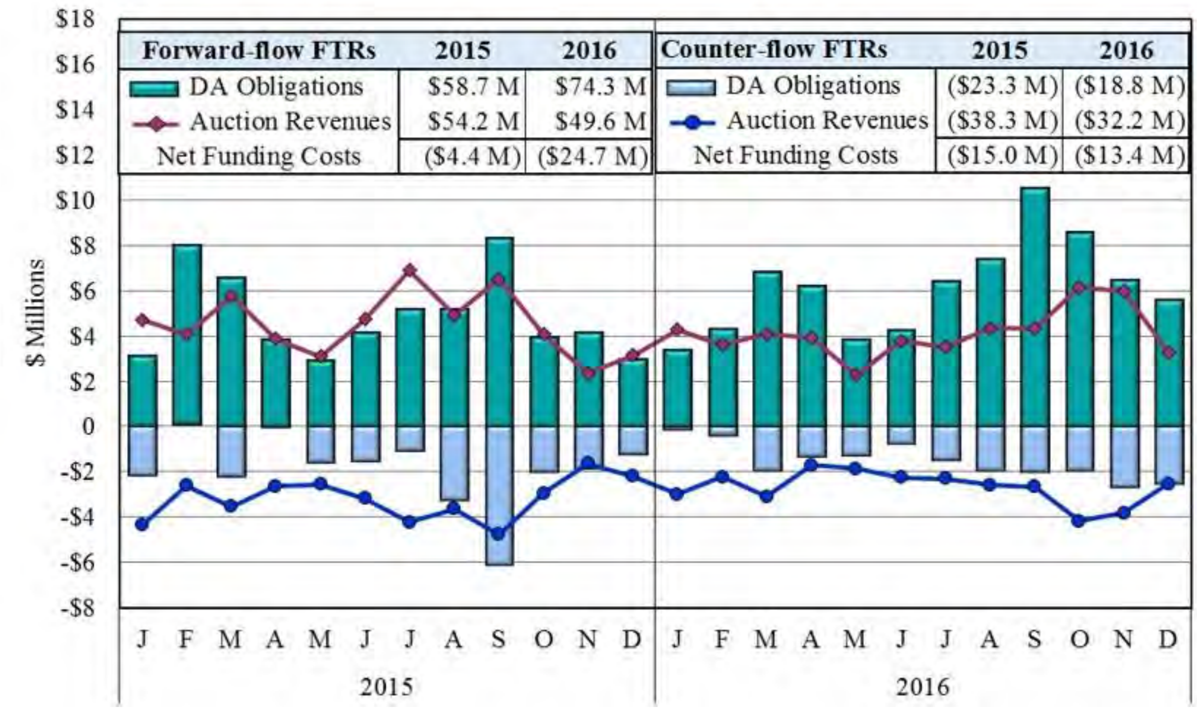
MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA with a negative residual (e.g., MISO can fund the purchase of counter-flow FTRs only with net

30 For example, imagine MISO has issued 250 MW of FTRs over an interface that now can accommodate only 200 MW of flow. MISO could sell 50 MW of counter-flow FTRs so that MISO's net FTR obligation in the day-ahead market would be only 200 MW.

revenues from same auction). This limits MISO's ability to resolve feasibility issues through the MPMA. In other words, when MISO knows a path is oversold, as in the example above, MISO often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always inefficient, because it may be more costly to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 29 compares the auction revenues from the MPMA prompt month (the first full month after the date of the auction) to the day-ahead FTR obligations associated with the FTRs sold. It separately shows forward direction and counter-flow FTRs. The net funding costs shown in the inset tables represent the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold forward-flow FTRs at a price less than their ultimate value or counter-flow FTRs at a price less negative than their ultimate value.

Figure 29: Prompt-Month MPMA FTR Profitability
2015–2016



This figure shows that MISO sold forward-flow FTRs at nearly $25 million less than their ultimate value in 2016, and net funding costs significantly increased. Similarly, MISO paid participants 71 percent more to accept counter-flow FTRs than the value of these obligations in 2016. While the negative auction residual restriction artificially limits MISO's ability to sell counter-flow FTRs, this limitation benefited MISO's customers in 2016 based on the pattern of inflated prices for counter-flow FTRs shown in the figure.

Overall, these results indicate that the MPMA is less liquid than is necessary to erase the systematic differences between FTR prices and values. The best option for addressing this issue is to examine the rules and requirements that may be limiting participation in the FTR markets. If barriers to participation can be identified and eliminated, we would expect better convergence between the auction revenues and the associated day-ahead FTR obligations.

Additionally, if liquidity and performance can be improved, we recommend that MISO eliminate the arbitrary negative auction residual restriction. This will allow MISO to enter the day-ahead market with a feasible set of FTR obligations. If liquidity cannot be improved, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale for forward flow FTRs at unreasonably low prices or the sale of counter-flow FTRs at unreasonably high prices.

D. Improving the Utilization of the Transmission System

During 2016, MISO and the IMM continued to work with MISO and transmission operators on processes and procedures to enable greater utilization of the transmission network. This can be accomplished by operating to higher transmission limits, which would result from consistent use of improved ratings for MISO's transmission facilities, including:

- Temperature-adjusted transmission ratings;
- Emergency ratings; and
- Use of dynamic Voltage and Stability ratings.

As detailed in the Analytical Appendix, substantial savings could be achieved through wide-spread use of temperature-adjusted transmission ratings for all types of transmission constraints.[31] For contingency constraints, these temperature-adjusted ratings should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in the short-term if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits, but we have identified transmission owners that provide only normal ratings.

To estimate the congestion savings of using temperature-adjusted ratings, we used NERC/IEEE estimates of ambient temperature effects on transmission ratings and hourly local temperatures to calculate adjusted limits on real-time, binding transmission constraints. The value of increasing the transmission limits was calculated by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint. This analysis indicates that as much as $155 million in production costs savings could be achieved by fully adopting temperature-adjusted, short-term emergency ratings throughout MISO.

31 Temperature is one common dynamic factor. In some regions ratings are more dependent on other factors such as assumed ambient wind speed. This analysis evaluates only ambient temperature impacts.

In 2015, MISO implemented a pilot program to make use of temperature-adjusted, short-term emergency ratings on a number of key facilities, and this has matured into an ongoing program. In 2016, MISO expanded the number of facilities included in the program. The program has had clear benefits with no reliability issues, and expansion of the program will likely generate consirable savings on constraints throughout MISO. We recommend that MISO continue to work with transmission owners to gather and use temperature-adjusted, short-term emergency ratings in the real-time market. Additional savings could be achieved by using predictive ratings in the day-ahead market that would be based on forecasted temperatures and wind speeds. MISO is evaluating the costs and benefits of using predictive ratings in the day-ahead market.

E. Market-to-Market Coordination with PJM and SPP

MISO's market-to-market process under the Joint Operating Agreement (JOA) with neighboring RTOs enables the RTOs to efficiently manage constraints affected by both the monitoring and non-monitoring RTOs. The process allows each RTO to utilize re-dispatch from the other RTO's resources to manage its congestion if it is less costly than its own re-dispatch. Under the market-to-market process, each RTO is allocated firm rights (Firm Flow Entitlements or "FFEs") on the "coordinated" constraint. The process requires RTOs to calculate the shadow price on the constraint based on their own production cost of unloading it. The RTO with the lower-cost re-dispatch responds by reducing flow to help manage the constraint.

When the non-monitoring RTO provides relief and reduces its "market flow" below its FFE, the monitoring RTO will compensate it by paying it for marginal value of the difference between the non-monitoring RTO's FFE and its market flow. Conversely, if the non-monitoring RTO's market flow exceeds its FFE, it will pay the monitoring RTO for the excess flow.

While MISO and PJM implemented market-to-market coordination years ago, MISO initiated market-to-market with SPP on March 1, 2015. In the first few months in 2015 there were significant issues with the coordination on two SPP flowgates. MISO and SPP continue to work to resolve differences between their respective interpretations of the JOA.

Summary of Market to Market Settlements

Congestion on MISO market-to-market constraints rose 26 percent from $300 million in 2015 to $377 million in 2016. Some of this increase was associated with constraints that were not managed under conventional market-to-market coordination, including using overrides, safe operating modes, TLRs, or other processes to manage the congestion. Although sometimes justified, these alternatives are generally less efficient and lead to higher congestion costs. Congestion results on market-to-market constraints included:

- Congestion on external market-to-market constraints (those monitored by PJM and SPP) rose 23 percent.

- Net payments flowed from PJM to MISO because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.
  - Net payments from PJM totaled $44 million, an increase of 17 percent from 2015.
  - The increase was due to resources pseudo-tying into PJM and corresponding definition of new market-to-market constraints, and PJM's flawed interface pricing methodology that generally inflates congestion payments to imports and exports.
- MISO's market-to-market settlements with SPP in 2016 resulted in net payments of $4.9 million from MISO to SPP.

Evaluation of the Market-to-Market Coordination

We evaluate the effectiveness of the market-to-market process by tracking the convergence of the shadow prices of market-to-market constraints in each market. When it is working well, the non-monitoring RTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the monitoring RTO's relief. Our analysis shows that for the most frequently binding market-to-market constraints, the market-to-market process generally contributes to shadow price convergence over time and substantially lowers the monitoring RTO's prevailing shadow price when the market-to-market process is initiated.

Convergence is much less reliable in the day-ahead market, but MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016. The RTOs have not actively utilized this process so it has not had substantial effects. However, we will continue to evaluate the effectiveness of this process in improving day-ahead market outcomes. SPP has not agreed to implement a similar day-ahead coordination procedure.

While the market-to-market process improves efficiency overall, we evaluated three issues that can reduce the efficiency and effectiveness of coordination:

- Failure to test all constraints that might qualify to be new market-to-market constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as market-to-market; and
- Delays in activating market-to-market constraints for coordination after they have been classified as market-to-market.

Each of these issues is significant because when a market-to-market constraint is not identified or activated, the savings of enlisting the non-monitoring RTO to provide economic relief on the constraint disappear. It also raises serious equity concerns because the non-monitoring RTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the monitoring RTO. We developed a series of screens to identify constraints that should have been coordinated but were not because of the issues listed above. These screens identified 263 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. We then quantified the congestion on these constraints, which is shown in Table 6.

Table 6: Congestion on Constraints Affected by Market-to-Market Issues in 2016
$ Millions

Category of Issue	PJM	SPP	Total
Never classified as M2M	$66.4	$125.4	$191.8
M2M Testing Delay	$21.4	$19.3	$40.7
M2M Activation Delay	$2.7	$2.3	$5.0
Total	**$90.4**	**$147.1**	**$237.5**

These results indicate that the process for testing and activating market-to-market constraints can be improved significantly with both PJM and SPP. More than 80 percent of the congestion affected by these issues resulted from failures to designate constraints as market-to-market constraints that appeared to qualify under the JOA criteria. This indicates that the RTOs should improve the automation of their testing process to ensure that constraints are appropriately tested and activated to eliminate these issues.

Finally, one key insight that has emerged from our evaluation of some of the most costly market-to-market constraints is that sometimes it is efficient for the non-monitoring RTO to take monitoring responsibility for a constraint. This occurs when the non-monitoring RTO has the vast majority of the effective relief capability (and likely the most market flows). Hence, we recommend that MISO continue working with SPP and PJM to implement a procedure for the monitoring RTO to transfer the monitoring responsibility for a market-to-market constraint to the non-monitoring RTO when appropriate.

F. Effects of Pseudo-Tying MISO Generators

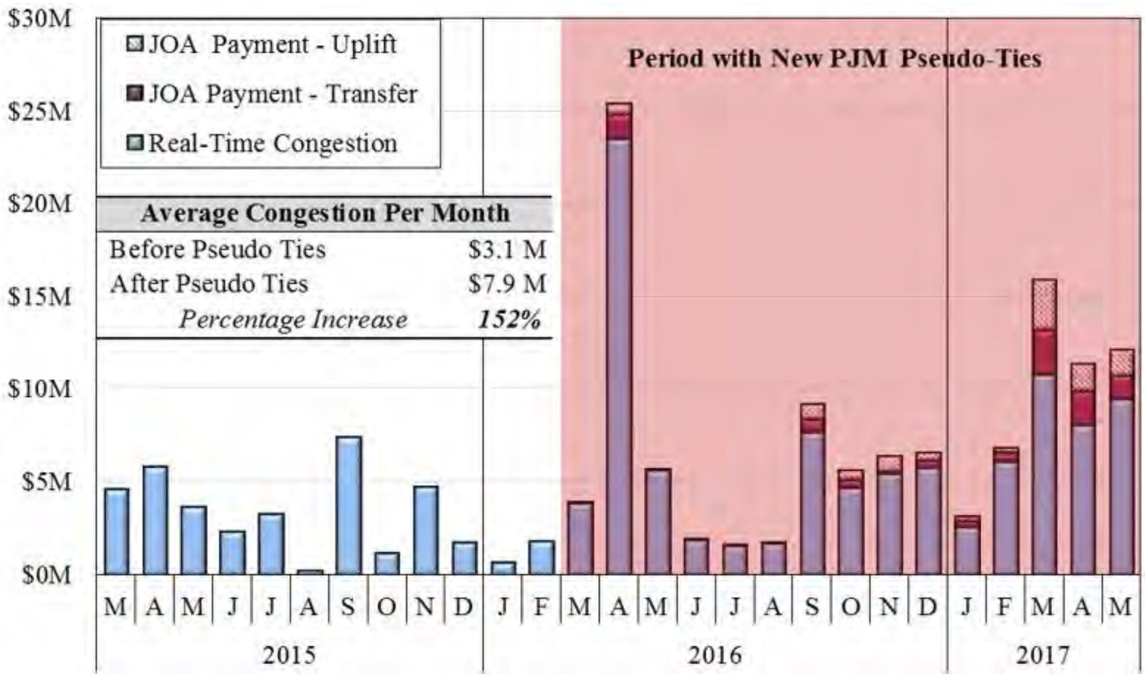
In recent years, increasing quantities of MISO capacity have been exported to PJM. PJM has recently implemented rules that require external capacity to be pseudo-tied to PJM. Beginning in 2015 and continuing into 2017, we have been raising serious concerns about this trend because allowing PJM to take dispatch control of large numbers MISO generators will:

- Cause forward flows over a large number of MISO transmission facilities that are difficult to manage; and
- Transfer control of generators that relieve other MISO constraints so that MISO will no longer have access to them to manage congestion on these constraints.

The first issue can be partially addressed to the extent that these constraints will be defined as market-to-market constraints and, therefore, coordinated with PJM. However, this coordination is not as effective as dispatch control and many constraints will not be coordinated. Figure 30 shows our evaluation of the effects of pseudo-tying the generators to PJM. This shows the value of real-time congestion on constraints that qualified as new market-to-market constraints only because of the resources that are pseudo-tied to PJM. The shading shows the period when MISO units were pseudo-tied to PJM. The purpose of this analysis to determine whether the pseudo-ties are leading to less efficient congestion management and higher congestion costs as a result.

Figure 30 shows that the real-time congestion values per month on the constraints affected by the pseudo-tied resources increased by 152 percent. This increase occurred largely because pseudo-tied units located on MISO's transmission system are now under the dispatch control of PJM, which is undermining MISO's ability to efficiently manage congestion on the affected portions of the MISO transmission system. This is a serious issue, not only because of the increased congestion on these constraints, but also because the pseudo-tied units affect many other MISO constraints that are not market-to-market constraints because they do not satisfy the criteria.[32]

Figure 30: Effects of Pseudo-Tying MISO Resources to PJM
2016



We further evaluated these concerns by assessing how efficiently the current 12 PJM - pseudo-tied units were dispatched when they affected constraints on MISO's system. We did this by calculating the inefficient production costs that they incurred (relative to the MISO LMP at their location) divided by their total energy production costs in hours when congestion was greater than $5 per MWh at the units' locations. In 2016, this evaluation showed:

- Eight of the twelve units exhibited average inefficiencies greater than **20 percent** when online (i.e., running at much higher or lower levels than optimal in congested periods).
- When we include periods when the pseudo-tied units were not committed by PJM even though they were clearly economic based on MISO's LMPs, the weighted-average inefficiency exceeded **26 percent** for all the pseudo-tied units.

We continue to be very concerned about the increasing quantities of MISO generators that are pseudo-tying to PJM. We continue to recommend that MISO and PJM develop procedures for

[32] MISO also loses the ability to economically commit/decommit pseudo-tied units to manage congestion.

firm capacity delivery as a more efficient and reliable alternative to pseudo-tying resources to PJM. To facilitate this solution, we have filed a Section 206 complaint against PJM's tariff to eliminate its current requirement that all external resources be pseudo-tied to PJM.[33]

G. Congestion on Other External Constraints

In addition to congestion from internal and external market-to-market constraints, congestion in MISO can occur on external constraints when other system operators call for Transmission Line-Loading Relief (TLRs), which causes MISO to activate the external constraint in MISO's real-time market. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers. MISO receives relief requests that are often inefficient and inequitable for these constraints because:

- MISO receives relief obligations based on forward direction flows, even if on net (when reverse-direction flows are included) its market flows are relieving the constraint; and
- Virtually all of MISO's flows over external constraints are deemed to be non-firm even though most are associated with dispatching network resources to serve MISO's load.

As a result, these external constraints often bind severely and produce substantial costs in MISO. Further, we have generally found that the external TLR constraints affecting MISO are often not physically binding during the periods when they are severely binding in MISO. To remedy these issues, we have recommended that MISO pursue a JOA with TVA that would allow TVA and MISO to coordinate the relief requested on each other's transmission system more efficiently than is occurring under the current TLR process. To quantify the potential value of such a JOA to MISO, Table 7 shows instances where TVA had lower-cost relief available than MISO on MISO's constraints (first row), and TVA's constraints (second row). The columns show the congestion value on these constraints and the potential savings from coordination.

Table 7: Economic Relief from TVA Generators
2016

Types of Constraints	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$169.6 M	$16.9 M
TVA (TLR) Constraints binding in MISO	$21.1 M	$4.9 M
Total	$190.7 M	$21.8 M

This analysis shows it would extremely valuable to coordinate congestion management with TVA, which would lower the costs of managing congestion on both systems, make MISO's relief obligations to TVA more equitable, and reduce price distortions caused by TVA's TLRs.

33 See Complaint filed in Docket No. EL17-62, April 5, 2017.

VII. External Transactions

A. Overall Import and Export Patterns

As in prior years, MISO remained a substantial net importer of energy in both the day-ahead and real-time markets in 2016:

- Hourly net imports in the day-ahead and real-time markets averaged 2.4 and 5.3 GW, respectively.
- MISO's largest and most actively-scheduled interface is the PJM interface. MISO was a net importer from PJM in 2016.
  - Hourly average real-time imports from PJM were 1,175 MW.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.

Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. These interchange adjustments are essential from both economic and reliability standpoints. Scheduling that is responsive to the interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area. However, arbitrage of interregional price differences is hindered by the fact that participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. Additionally, the lack of RTO coordination of participants' schedules leads to substantial errors in the aggregate quantities of transaction schedule changes.

To evaluate the efficiency of interregional scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions. Two-thirds of the transactions with PJM were scheduled in the profitable direction, while 63 percent of those scheduled in real time and settling at the real-time prices were profitable.

Even though transactions are scheduled in the efficient direction more than half of the time, large untapped savings are available because it is often economic to schedule significantly more interchange or less interchange than was scheduled. Many hours still exhibit large price differences that offer particularly large savings. MISO and PJM plan to address these issues by introducing "Coordinated Transaction Scheduling" (CTS) in late 2017, which allows the RTOs to adjust transaction schedules every 15 minutes based on forecasted price differences between the two markets. In late 2014, PJM implemented a comparable approach with the New York ISO (NYISO). Early in 2016, we filed comments on the MISO and PJM CTS proposal.[34]

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[34] Motion To Intervene Out Of Time and Comments Of Potomac Economics, Ltd., filed in Docket No. ER16-533, Jan. 22, 2016.

While we supported the CTS filing, we requested that FERC mandate a change based on analysis of the market results from the CTS provisions implemented between NYISO and both PJM and ISO-NE. Our analysis showed that the CTS is much more liquid between NYISO and ISO-NE than between NYISO and PJM. We attributed this partly to the charges associated with the CTS transactions. We therefore recommended that FERC Order PJM to eliminate all CTS charges.

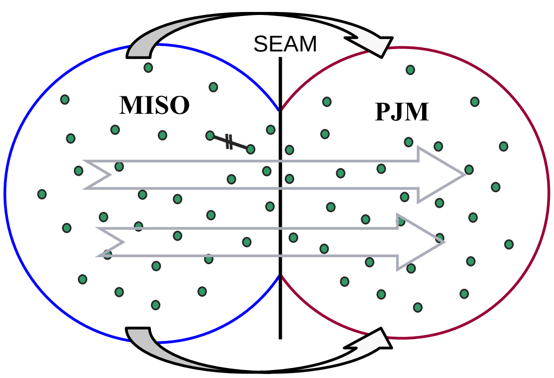
B. Interface Pricing and External Transactions

Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to arbitrage the differentials between the two interface prices. Interface pricing is essential because:

- It is the sole means to facilitate efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is an essential basis for CTS to maximize the utilization of the interface.

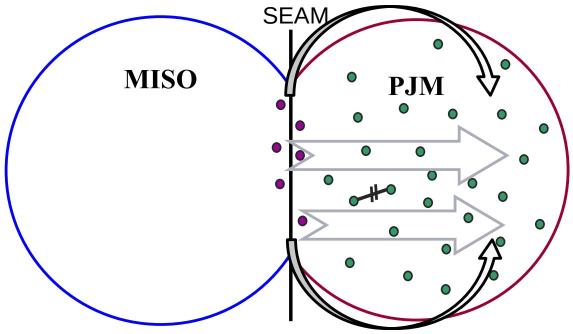
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses – each RTO would simply post the interface price as the cost of the marginal resource on their system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost system to the higher-cost system until the SMPs come into equilibrium (and generation costs are equalized). However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from cross-border transfers (imports and exports).

Like the locational marginal price at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In contrast, the source of an import (or sink for an export) is not known, so it must be assumed in order to calculate the congestion effects. This is known as the "interface definition." If the interface definition reflects where the power is actually coming from (import) or going to (export), the interface price will provide an efficient incentive to transact and traders' responses to these prices will lower the total costs for both systems.



In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units) as shown in the figure to the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.

Interface Pricing with PJM



However, PJM's assumptions are much different. It assumes the power sources and sinks from the border with MISO, as shown in the figure to the right. This approach tends to exaggerate the flow effects of imports and exports on any constraint near the seam because it underestimates the amount of power that will loop outside of the RTOs.

We have identied the location of MISO's marginal generators and confirmed that they are distributed throughout MISO, so we remain concerned that PJM's interface definitions on all of its interfaces tend to set inefficient interface prices. We believe that the inaccuracy of PJM's congestion components plays a major role in causing MISO to be a net importer from PJM (1.2 GW on average). For example, we previously showed that in 2015:

- MISO's system marginal price was 29 percent ($7.56/MWh) lower than PJM's on average, suggesting that MISO should be exporting power to PJM.
- However, PJM's average congestion component at the interface was -$4.10 per MWh, which substantially changed the incentive of participants to schedule imports and exports.
- This suggested that, on average for 2015, every MW of export from PJM to MISO would produce more than $4 per MWh of congestion savings.
- If exports do not actually provide this much relief, PJM will incur substantial excess congestion costs and the dispatch will be inefficient.

These results underscore the significance of these interface pricing flaws. We also believe that PJM's inaccurate interface prices led to inefficient day-ahead schedules that inflated the market-to-market costs incurred by PJM. In 2015, we estimated that PJM's congestion settlements at the MISO interface resulted in overpayments to transactions of almost $45 million.

Finally, we raised a concern in our *2012 State of the Market Report* that MISO and PJM were including redundant congestion components in their interface prices for M2M constraints (because these constraints are active in both markets simultaneously). This redundant settlement tends to overpay transactions that are expected to help relieve a constraint and overcharges transactions that are expected to aggravate a constraint. We recommended that the RTOs eliminate this redundancy by simply allowing the monitoring RTO alone to price the congestion for its constraints at the interface (i.e., MISO fully price MISO's constraints at the interface). Instead, the RTOs implemented PJM's proposal that RTOs adopt a common interface comprised of a limited number of nodes close to the MISO-PJM seam in the second quarter of 2017. This was a bad choice, as our analysis indicated that this would produce less efficient and more volatile interface prices. We will monitor the results of these changes to document these inefficiencies and work with the RTOs to develop better solutions over the long term. Similar discussions have begun with SPP, because MISO implemented a market-to-market process with SPP in March of 2015. However, SPP has not yet taken a position on any particular interface pricing proposal.

Interface Pricing for Other External Constraints

PJM market-to-market constraints are only one type of external constraint that MISO includes in its real-time market. MISO also activates constraints located in external areas when neighboring system operators call TLRs and MISO re-dispatches its generation to meet its flow obligation. Although we have concerns that are described earlier in this section regarding the cost of external constraints, it is nonetheless appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs – this enables MISO to respond to TLR relief requests as efficiently as possible. While re-dispatching internal generation is required, MISO is not obligated to pay importers and exporters that may relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that its external transactions may provide. Because MISO receives no credit for this relief and no reimbursements for the millions of dollars in costs it incurs each year, it is inequitable for MISO's customers to bear these costs.

In addition to the inequity of these congestion payments, they motivate participants to schedule transactions inefficiently for two reasons:

- In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. MISO's additional payment is duplicative and inefficient.
- MISO's shadow cost for external TLR constraints is generally overstated by multiples relative to the true marginal cost of managing the congestion on the constraint. This causes the interface price to provide inefficient scheduling incentives.

One should expect that this will result in inefficient schedules and higher costs for MISO customers. Therefore, we continue to recommend that MISO take the necessary steps to remove all other external congestion from its interface prices, regardless of its decision related to the interface.

VIII. Competitive Assessment and Market Power Mitigation

This section contains our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2016. Market power in electricity markets exist when a participant has the ability and incentive to raise prices. Market power can be indicated by a variety of empirical measures, and we discuss measures that are applicable to the MISO markets.

A. Structural Market Power Indicators

Economists and antitrust agencies often utilize market concentration metrics to evaluate the competitiveness of a market. The most common metric is the Herfindahl-Hirschman Index (HHI), which is a statistic calculated as the sum of the squared market shares of each supplier. More concentrated markets will have a higher HHI index. Market concentration is low for the overall MISO area (595), but relatively high in some local areas, such as the WUMS Area (2805) and the South region (3749). In MISO South, a single supplier operates nearly 60 percent of the generation. However, the metric does not include the impacts of load obligations, which affect suppliers' incentives to raise prices. It also does not account for the difference between total supply and demand, which is important because larger differences (i.e., excess supply) result in more competitive markets. Hence, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is "pivotal." A supplier is pivotal when its resources are necessary to satisfy load or to manage a constraint. Our regional pivotal supplier analysis indicates that the frequency with which a supplier is pivotal rises sharply with load. This is typical in electricity markets, because electricity cannot be economically stored. Hence, when load increases, excess capacity will fall, and the resources of large suppliers may be required to meet load.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints into constrained areas, including the five Narrow Constrained Areas (NCAs) and the two Broad Constrained Areas (BCAs) that are defined for purposes of market power mitigation. NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). A BCA is defined when non-NCA transmission constraints bind and includes all generating units with significant impact on power flows over the constraint. Our results showed that a supplier was frequently pivotal in both types of constrained areas:

- Ninety-three percent of the active BCA constraints had at least one pivotal supplier, and at least one BCA constraint with a pivotal supplier was binding in nearly all intervals.
- In the two MISO South NCAs, 99 percent of active constraints had a pivotal supplier.
- The MISO Midwest NCAs had pivotal suppliers on 98 percent of the active constraints.

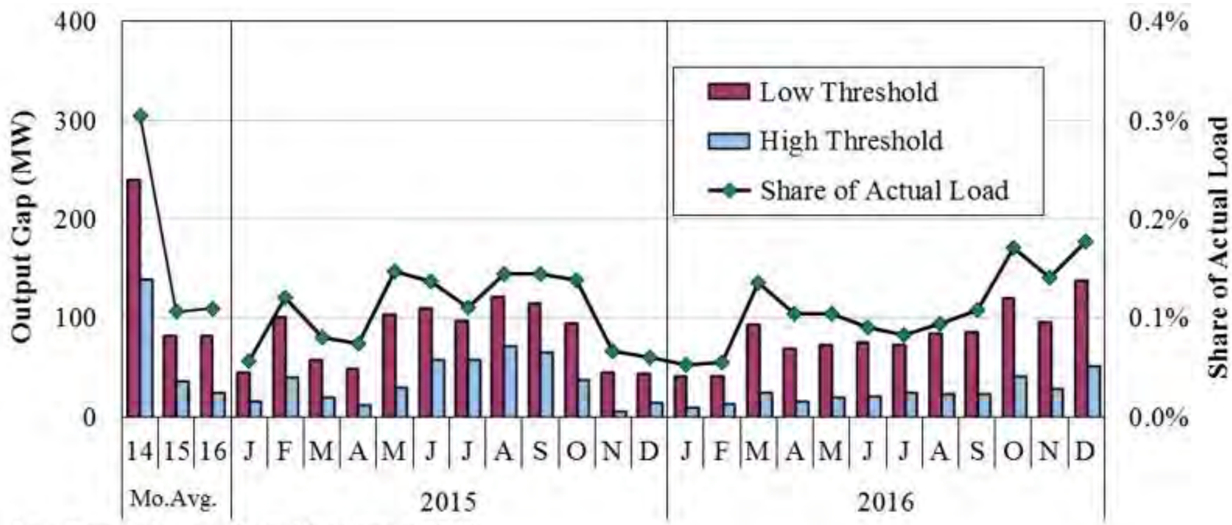
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate metrics of market competitiveness. We calculated a price-cost mark-up that compares the system marginal price, based on actual offers, to a simulated system marginal price that assumes all suppliers had submitted offers at their estimated marginal cost. We found an average system marginal price mark-up of 0.5 percent in 2016, varying monthly from a high of 3.4 percent to a low of -1.7 percent. The low average mark-up indicates that MISO's energy markets produced competitive results.

The next figure shows the "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using the Tariff's conduct mitigation threshold (the "high threshold") and a "low threshold," equal to one-half of the conduct mitigation threshold. Additionally, the output gap includes units that are online and withholding energy by submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 31: Economic Withholding – Output Gap Analysis
2015–2016



Low Threshold Results by Unit Status (MW)

	14	15	16	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	98	27	11	12	31	5	4	15	43	54	66	57	32	0	10	6	11	0	1	0	1	15	13	13	30	21	25
Online	140	55	71	34	70	53	46	90	68	43	56	57	63	45	34	36	31	94	69	73	74	58	72	73	89	75	113

High Threshold Results by Unit Status (MW)

	14	15	16	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	82	23	10	11	17	5	3	11	34	49	58	50	25	0	7	5	10	0	1	0	1	15	11	11	26	21	24
Online	57	14	15	6	24	16	10	19	24	9	14	16	14	6	8	6	5	25	16	20	20	11	14	14	16	8	29

The figure shows that the average monthly output gap level was 0.11 percent of load in 2016, which is effectively *de minimus*. Although these results raise no overall competitive concerns, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

We also evaluate the overall competitiveness of the MISO markets by calculating a a "price-cost mark-up." This metric compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. The unit-specific reference levels calculated for each unit is the competitive benchmark we use in this analysis. Our analysis revealed the price-cost mark-up was effectively zero in 2016, which indicates that the MISO markets were highly competitive.

C. Summary of Market Power Mitigation

The instances of market power mitigation in 2016 were appropriate, and effectively limited the exercise of market power. Imposition of mitigation in the energy market and on RSG payments both fell substantially in 2016, as described below.

Market power mitigation in MISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly-specified criteria. The mitigation measure for economic withholding caps a unit's offer price when it exceeds the conduct threshold and the offer raises clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently. The mitigation thresholds differ depending on the two types of constrained areas that may be subject to mitigation: BCAs and NCAs. The market power concerns associated with NCAs are greater because they are chronic. As a result, conduct and impact thresholds for NCAs can be substantially lower than they are for BCAs (they depend on the frequency with which NCA constraints bind). The lower mitigation thresholds in the NCAs generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs.

Energy offer mitigation did not occur in the day-ahead market, but increased in the real-time market in 2016. Mitigation was imposed in less than 4 percent of hours in the real-time market. Assuming the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to the exercise of market power as long as it is liquid, with fulsome participation by physical and virtual trading participants. Hence, mitigation was not imposed in any hours in the day-ahead market. Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive. However, irrational regulation offers by one supplier were mitigated relatively frequently.

RSG payments occur when a resource is committed out of market to meet the system's capacity needs, local reliability requirements, or to manage congestion. If the resource offers its unit with inflated economic or physical parameters, it may inflate its RSG payments and be mitigated.

Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition is generally robust to satisfy these needs.

In 2016, total RSG mitigation dollars fell by 76 percent as mitigation of RSG paid to resources committed for VLR needs decreased substantially, mainly because VLR commitments became less frequent and less costly. VLR requirements are one frequent cause of commitments for which participants may be paid RSG. Most VLR commitments are in MISO South and are subject to tighter mitigation thresholds because competition to satisfy these requirements is limited. Mitigation of RSG payments incurred to manage congestion remained low in 2016.

D. Evaluation of RSG Conduct and Mitigation Rules – Dynamic NCAs

The market power mitigation measures are effective, in part, because MISO has the authority to designate NCAs in chronically-constrained areas, which results in the application of tighter conduct and impact thresholds to address the heightened market power concerns in these areas. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period. Consequently, when transitory conditions arise that create a severely-constrained area with pivotal suppliers, an NCA is often not defined because it is not expected to exhibit binding constraints for 500 hours in a 12-month period.

Transitory congestion can result in substantial local market power. This often occurs when system changes occur related to transmission outages or generation outages. Once the congestion pattern begins, suppliers may recognize that their units are needed to manage the constraints and exercise market power under the relatively generous BCA thresholds.

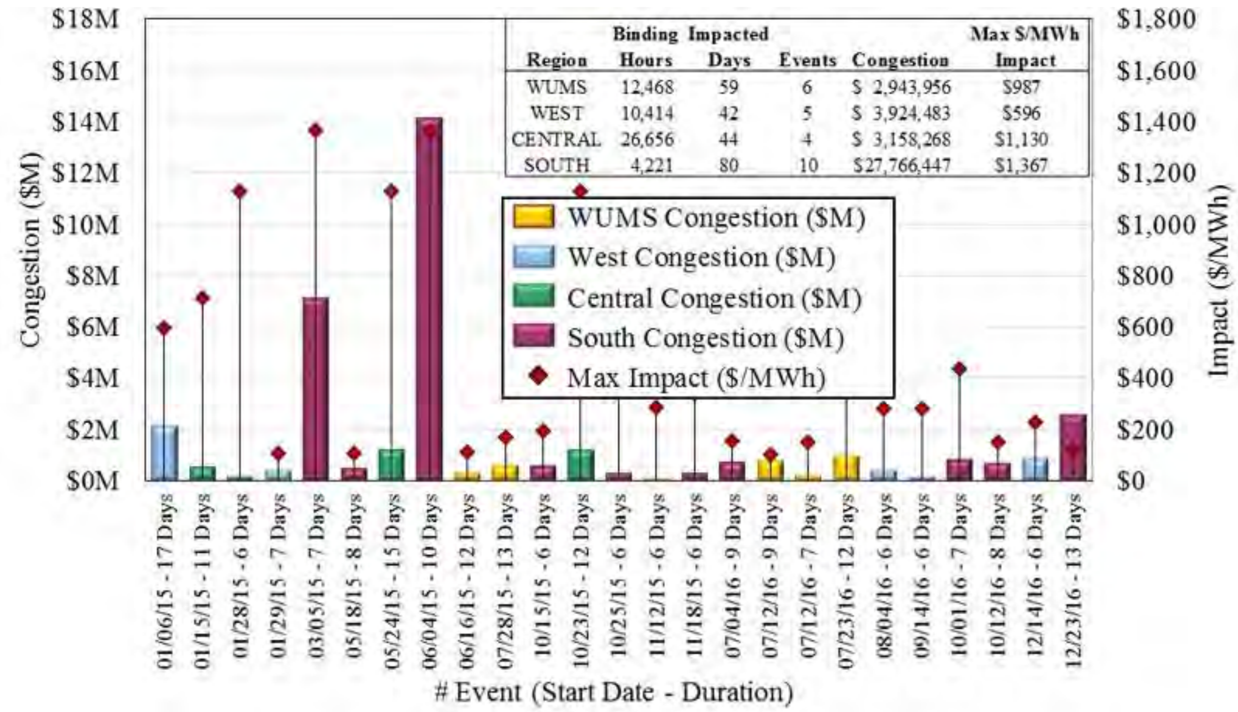
To address this concern, we have recommended that MISO expand Module D of its tariff to allow it to establish "dynamic" NCAs when transitory conditions arise that lead to sustained congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh and be triggered by the IMM when mitigation would be warranted under this threshold *and* congestion is expected in at least 15 percent of hours (more than double the rate that would be required to permanently define a NCA). This provision will help ensure that transitory network conditions do not allow the exercise of substantial local market power.

To assess the need for this enhancement, we performed an evaluation to determine how frequently dynamic NCAs would have been defined and when mitigation would have been warranted in 2015 and 2016. The results of this evaluation are shown in Figure 32 below, which shows the results from applying our two proposed criteria over the past two years:

- Conduct and impact is identified at $25 per MWh thresholds in a load pocket; and
- The load pocket is binding in at least 15 percent of the intervals over 5 days.

The left axis in figure Figure 32 shows the value of real-time congestion during each Dynamic NCA event (the sum of the shadow price times the flow). The right axis shows the maximum impact of the market power mitigation during the Dynamic NCA event. The events themselves are color coded to show the region in which they occurred.

Figure 32: Dynamic NCA Evaluation of Events
Impacts and Congestion, 2015–2016



Our results show that applying our proposed criteria in 2015 and 2016 would have resulted in:

- The declaration of 25 Dynamic NCAs with an average duration of nine days.
- The maximum price impacts during these events would have ranged from $105 per MWh to $1400 per MWh.
- The average price impacts over each entire event throughout the relevant constrained area ranged from $6.50 per MWh to $424 per MWh.

While Dynamic NCAs would have been declared in all of MISO's regions, the most frequent occurrences and largest impacts of Dynamic NCAs would have been in MISO South. This is not surprising because MISO South has experienced severe congestion resulting from transmission and generation outages.

IX. DEMAND RESPONSE

Demand response (DR) improves operational reliability, contributes to resource adequacy, reduces price volatility and other market costs, and mitigates supplier market power. Therefore, it is important to provide efficient incentives for the development of DR and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes. Table 8 shows overall DR participation in MISO, NYISO, and ISO-NE in the prior three years.

Table 8: Demand Response Capability in MISO and Neighboring RTOs
2014–2016

		2016	2015	2014
MISO[1]		**10,721**	**10,563**	**10,356**
	Behind-The-Meter Generation	4,089	4,213	4,072
	Load Modifying Resource	4,616	5,121	4,943
	DRR Type I	525	330	372
	DRR Type II	75	116	76
	Emergency DR	1,416	782	894
NYISO[3]		**1,653**	**1,325**	**1,211**
	ICAP - Special Case Resources	1,192	1,251	1,124
	Of which: Targeted DR	372	385	369
	Emergency DR	75	75	86
	Of which: Targeted DR	14	14	14
	DADRP	0	0	0
ISO-NE[4]		**2,600**	**2,685**	**2,487**
	Real-Time DR Resources	702	692	796
	Real-Time Emerg. Generation Resources	2	300	255
	On-Peak Demand Resources	1,386	1,222	997
	Seasonal Peak Demand Resources	510	471	439

[1] Registered as of December 2015. All units are MW. Source: MISO website, published at: www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/DemandResponse.aspx.

[2] Roughly 2/3 of the EDR are also LMRs.

[3] Registered as of July 2016. Retrieved May 2, 2017. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

[4] Registered as of Jan. 1, 2017. Source: ISO-NE Demand Response Working Group Pesentation.

The table shows that MISO had nearly 11 GW of demand-response capability available in 2016, which is a larger share than in neighboring RTOs. MISO's capability exhibits varying degrees of responsiveness. More than 90 percent of the MISO DR is in the form of interruptible load (i.e., "Load-Modifying Resources," or LMR) developed under regulated utility programs and Behind-

The-Meter Generation (BTMG). MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions.

Although 21 Demand Response Resources ("DRRs") were active in the MISO markets in 2016, they only cleared a small amount of energy and reserves in the MISO markets. All of these units were DRR Type 1 (non-dispatchable DRRs). MISO considers DR a priority and continues to actively expand its DR capability. As surplus capacity dissipates, DR resources are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. It is important, therefore, to ensure that real-time markets produce efficient prices when DR resources are deployed. Prior to an April 2017 deployment in MISO South, they had not been deployed since 2006.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently in 2016 overall, we recommend a number of improvements in MISO's market design and operating procedures. These twenty-five recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion: 7 total, 3 new.
- Operating Reserves and Guarantee Payments: 3 total, 2 new.
- Dispatch Efficiency and Real-Time Market Operations: 6 total, 3 new.
- Resource Adequacy: 9 total, 1 new.

Sixteen of the recommendations described below were recommended in prior State of the Market Reports. This is expected because some of the recommendations can require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes. Since these processes can be time consuming and software changes must be prioritized with other software projects, recommendations can take multiple years to complete.

MISO addressed three of our past recommendations, which were implemented in 2016 or are being implemented in early to mid-2017. We discuss recommendations that are addressed at the end of this section. Included in this section are also three recommendations that MISO has not agreed to pursue and we are removing pending further analysis of market outcomes. For any recurring recommendation, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendation.

A. Energy Pricing and Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, the spot prices produced by the real-time market affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, longer-term forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest priorities from an economic efficiency standpoint must be to produce real-time prices that accurately reflect supply, demand, and network conditions. A number of the following recommendations address this area.

2015-1: Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources.

Our analysis indicates that the Phase 1 implementation of ELMP is having a very small effect in allowing online peaking resources to set prices when they are the marginal source of supply in

MISO. This can be attributed to the eligibility rules that until recently allowed only five percent of the online peaking resources to potentially set prices. In May 2017, the set of eligible resources was expanded, which would have allowed 16 percent of online peaking resources to set prices. We recommend expanding the eligibility to include peaking resources with minimum runtimes up to two hours.

Additionally, there is no theoretical basis for distinguishing between peaking resources based on whether they were scheduled in the day-ahead market. Therefore, we recommend that peaking resources scheduled in the day-ahead market be eligible to set prices in the real-time energy market.

Finally, we find that ELMP's offline pricing has generally resulted in inefficient price reductions during shortage conditions. The offline peaking resources that set prices are rarely utilized and economic in the periods in which they set prices. Hence, we find they are are adversely affecting MISO's real-time prices and recommend that MISO suspend the offline pricing.

<u>Status</u>: MISO has implemented the Phase II changes to expand ELMP eligibility for online resources to those that could be accommodated without software changes, including expanding ELMP eligibility to online resources that can be started within 60 minutes (previously limited to 10 minutes). This filing was accepted by FERC in April 2017 and implemented on May 1, 2017. We believe the pool of ELMP-eligible resources should be expanded even further, extending the minimum run time threshold and including day-ahead committed resources, but these changes require software modification. MISO and the IMM plan to evaluate the benefits of greater expansion after evaluation of the Phase II implementation.

<u>Next Steps</u>: We encourage MISO to develop an estimate of the resources necessary to expand the eligibility further. The IMM is evaluating the performance of the Phase II changes and will provide feedback to MISO and the participants on the priority of further expansion.

2015-2: Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities.

Our analysis of transmission ratings submitted to MISO by transmission owners for use in MISO's real-time and day-ahead market shows that few transmission owners are utilizing MISO's capability to receive temperature-adjusted ratings. Most transmission owners provide seasonal ratings only, and we find that seasonal ratings can be up to 30 percent lower than the ratings that may be reliably used based on actual system conditions (e.g., ambient temperatures, wind forecasts, humidity). Our analysis showed potential savings of reduced congestion costs of $165 million in 2015 and $155 million in 2016 if transmission owners provide temperature-adjusted ratings.

Additionally, the transmission owner's agreement calls for transmission owners to provide short-term emergency ratings, which can be 10 to 15 percent higher than the normal rating. Our analysis also shows substantial potential savings in congestion costs that could be achieved by ensuring that all transmission owners provide short-term emergency ratings that can be used by MISO as appropriate.

We recommend that MISO work with transmission owners to ensure more complete and timely use of both temperature-adjusted (or other factors such as ambient wind speed) and short-term emergency ratings. Additionally, we recommend that MISO work with its Transmission Owners to establish a consistent rating methodology to communicate an expectation that emergency ratings should be based on short-term temperature-adjusted ratings.

Status: In 2016, MISO implemented a pilot program with one transmission operator that has been highly successful at reducing congestion costs and it has been expanded. However, MISO has not developed a comprehensive review program to identify opportunities to improve ratings across its entire system nor developed a day-ahead program to use predictive ratings. MISO has not yet aligned this recommendation with a Roadmap project called "Application of Dynamic and Predictive Ratings." However, this project proposed by MISO stakeholders is consistent with this recommendation. MISO is reviewing this Roadmap initiative but has provided no update or status other than to indicate that this is a low priority.

Next Steps: MISO should begin working with other Transmission Operators to expand its pilot program to other areas. To facilitate this expansion, we recommend that MISO develop procedures to evaluate MISO's ability to manage post-contingent flows when it utilizes emergency ratings. Additionally, we recommend that MISO develop procedures to develop predictive temperature-dependent ratings in its day-ahead market.

2012-5: Introduce a virtual spread product.

Seventy percent of price-insensitive virtual bid and offer volumes (and 17 percent of all volumes) in 2016 were "matched" transactions. To the extent that the matched transactions are attempting to arbitrage congestion-related price differences, a virtual product to allow participants to do this price sensitively would be more effective and efficient. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., schedule a transaction). This would reduce the risk participants currently face when they submit a price-insensitive transaction because price-insensitive transactions can be highly unprofitable for the participant. They can also produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO continues to discuss this recommendation with stakeholders and has held a number of workshops with stakeholders to explore the development of such a product. MISO continues to evaluate costs and benefits, and develop software improvements that will mitigate the impact of a virtual spread product on the day-ahead solution times. Currently this recommendation is included in MISO's Roadmap as a low priority and forecasted for further evaluation in the third quarter 2019.

Next Steps: MISO should complete an evaluation of both the benefits of a spread product, as well as the economic costs and other impacts on day-ahead market operations of introducing this product. This will allow MISO and its stakeholders to determine the priority for the virtual spread product.

2014-3: Improve external congestion related to TLRs by developing a JOA with TVA.

The implementation of market-to-market coordination with SPP has significantly reduced the TLR inefficiencies. TLRs called by SPP previously had the largest effects on MISO's prices. However, the integration of MISO South has increased the frequency of TLRs called by TVA. Subtantial benefits for MISO could be achieved by developing a JOA that would allow MISO's day-ahead scheduled flows to be considered firm for purposes of relief calculations, and perhaps even allow the TLR process to be replaced with an economic coordination process that would allow MISO and TVA to procure economic relief from each other.

Status: In the past few years, MISO has met with TVA a number of times to resolve specific transmission coordination and TLR issues, however MISO has not resolved this issue.

Next Steps: We continue to monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs. The next step for this recommendation is to work with TVA to explore the development of a JOA that would mitigate the adverse effects of the TLRs.

2016-1: Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load.

We recommend that MISO reform its Operating Reserve Demand Curve (ORDC). Because it is the primary determinant of the shortage pricing in MISO's energy markets, establishing an ORDC that reflects reliability is essential. MISO's current ORDC does not reflect reliability value, overstating the reliability risks for small shortages and understating them for deep shortages. Additionally, PJM's recent changes will price shortages as high as $6,000 per MWh (sum of the shortage pricing and capacity performance settlement), which will lead to inefficient imports and exports when both markets are tight.

An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to:

*probability of losing load * net value of lost load (VOLL)*

The economic ORDC has substantial advantages. The shortage pricing under the economic ORDC will track the escalating risk of losing load. In the range where most shortages occur, the economic ORDC is sometimes higher and sometimes lower than the current curve, so it should not substantially increase consumer costs for these shortages. For MISO to implement this recommendation, it would need to update its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load.

Status: This is a new recommendation

2016-2: Improve procedures for M2M Activation and Coordination including identifying, testing, and transferring control of M2M Flowgates.

The procedures for identifying, testing, activating, and transferring control (when warranted) of M2M constraints are all critical to successful and efficient coordination of congestion management. Some elements in these these processes are not highly automated and involve considerable level of discretion and interaction between multiple business areas within and across RTOs. We identified some delays in establishing new M2M constraints or activating existing M2M constraints that reduce the effectiveness of M2M coordination. Additionally, some constraints were not established as M2M constraints although they appear to qualify under the M2M tests.

Our analysis indicates $238 million of congestion costs could have been more effectively managed if M2M coordination testing and activation procedures were more complete and timely. Further, a significant portion of this congestion, our analysis finds, could be provided by more efficient redispatch options. We therefore recommend that MISO improve the automation of its procedures for the testing and activation of M2M constraints, improve the logging of testing results, and develop criteria with its JOA partners to transfer control of M2M constraints when it would be beneficial to do so.

Status: This is a new recommendation.

2016-3: Enhanced Transmission and Generation Planned Outage Approval Authority

MISO is responsible for approving the schedules of planned transmission and generation outages. This approval process considers only reliability concerns associated with requested outages and not the potential economic costs. In other words, MISO can only deny or reschedule a planned outage if it threatens reliability. As a result, we have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. From January 2016 to May 2017, multiple simultaneous generation outages contributed to almost $457 million in real-time congestion costs – 25 percent of all real-time congestion costs.

Most of the other RTOs in the Eastern Interconnect have authority comparable to MISO's, with the exception of ISO New England. The ISO New England does have the authority to examine costs in evaluating and approving transmission outages. It can deny or move outages if doing so will result in "significantly reduced congestion costs."[35] The ISO New England program has been found to have been very effective at reducing congestion costs.[36]

We recommend that MISO explore alternatives to improve coordination of transmission and generation outages, including expanding its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: This is a new recommendation.

B. Operating Reserves and Guarantee Payments

Many of MISO's reliability needs are addressed through its operating reserve requirements that result in resources being available to produce when system contingencies occur. However, to the extent that MISO has system needs that are not addressed by the operating reserve requirements, MISO may take out-of-market actions to commit resources that are not economic at prevailing prices and, therefore, require a guarantee payment to recover their as-offered costs. As a general matter, MISO's market requirements should reflect its operating needs, to the maximum extent feasible, to allow the markets to satisfy these needs efficiently and allow the market prices to reflect them. The recommendations in this section are generally intended to improve this consistency between market requirements and operating requirements. This section also recommends changes in guarantee payments designed to improve participants' incentives.

2014-2: Introduce a 30-minute reserve product to reflect VLR requirements and other local reliability needs.

MISO is incurring substantial RSG costs in a limited number areas to satisfy VLR requirements. These costs arise as MISO commits additional local resources to prepare the area to withstand both the largest potential contingency in the area as well as the second largest contingency. These requirements are attributable to the fact that some areas do not have resources that can start within 30 minutes to restore the lost reserves after the first contingency. In essence, MISO is committing resources to hold reserves on online resources.

We recommend that MISO create a local 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets (rather than through out-of-

35 ISO-NE Market Rules: Section III, Market Rule 1 – Appendix G; JUNE 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency, Presentation by ISO NE.

36 JUNE 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency, Presentation by ISO NE.

market commitments that result in uplift). This would be beneficial because it would provide market signals to build fast-starting units or other resources that can satisfy the VLR needs at a much lower cost (because they can satisfy the requirements while offline).

Additionally, to the extent that MISO operators perceive reliability needs more broadly that can be satisfied by a 30-minute reserve product, MISO should consider establishing market-wide requirements for 30-minute reserves. A number of other RTOs have 30-minute reserve products and it is valuable for pricing services that can be provided by peaking resources that cannot start in 10 minutes, which includes most of the peaking resources in MISO. It allows for an efficient expansion of MISO shortage pricing to include conditions when it is short of 30-minute reserves.

Status: This recommendation was originally proposed in our *2014 State of the Market Report*. MISO initially classified this recommendation as a high priority in the Roadmap process and assigned a forecasted implementation time in the second quarter of 2019. Subsequently, MISO merged this recommendation with another existing Roadmap project, *Develop Additional Short Term Capacity Reserve Requirements*, which is intended to address a similar 30-minute reserve requirement more broadly beyond the VLR areas. This project is currently planned for implementation in December 2021.

Next Steps: Given the benefits of this recommendation, MISO should increase the priority of this recommendation and accelerate its implementation. We also recommend that MISO consider implementing a 30-minute reserve product more broadly beyond the VLR areas.

2016-4: Establish regional reserve requirements and cost allocation.

We have identified a substantial number of resource commitments and associated RSG payments made in MISO Midwest or MISO South to satisfy regional capacity needs when the RDT is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region. These commitments are made outside of the market because MISO's markets do not include regional capacity requirements. We believe the 30-minute reserve product recommended in 2014-2 could be expanded to reflect these regional capacity needs. This would likely alter the resource commitments in the day-ahead market to satisfy these needs at overall lower costs. It will also price these requirements, including allowing the markets to price shortages when the regional resources are insufficient to satisfy the full reserve requirement.

Status: This is a new recommendation

2016-5: Reform DAMAP and RTORSGP rules to improve performance incentives, and reduce gaming opportunities and unjustified costs.

Our evaluation of DAMAP and RTORSGP reveals that significant amounts were paid to resources that were not performing well. These price volatility make-whole payments are intended to ensure that resource have incentives to be flexible and are not harmed financially from following MISO's dispatch instructions. Under the current formulas, however, some resources receive payments because they are running at an uneconomic dispatch level as a result of not following MISO's dispatch instructions. Suppliers should be accountable for poor generator performance and these payments were not intended to hold suppliers harmless for poor performance. Because poor performance can increase such payments, the current rules may enable manipulative strategies involving coordinating offer prices and deliberate poor performance. We have referred such conduct to the Commission's Office of Enforcement.

The only current means to address these concerns under the current rules are through eligibility criteria that cause a supplier to become ineligible if it exceeds MISO's Excessive and Deficient energy thresholds. Even with the improvements in these thresholds that we have recommended, these eligibility rules will not effectively address the performance and manipulation concerns. Therefore, we recommend that MISO incorporate a performance metric in the calculation of these make-whole payments that would reduce the payment by the amount that corresponds to resources' dispatch deviations.

Status: This is a new recommendation

C. Improve Dispatch Efficiency and Real-Time Market Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which includes satisfying the system's needs reliably and at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system and make a variety of changes to parameters and other inputs to the real-time market as necessary. Each of these actions can substantially affect market outcomes.

One of the principal challenges to achieving efficient real-time outcomes is the five-minute time horizon of the real-time market. When the needs of the system require that resources ramp up or down rapidly, substantial costs can be incurred and real-time prices can become highly volatile to reflect these costs. It is these ramp demands that have caused MISO's real-time energy prices to be more volatile than any of the other RTOs in the Eastern Interconnect. These ramp demands can be satisfied at a much lower cost if they are anticipated and if the dispatch of resources is modified to account for them over a timeframe longer than five minutes, or if the system holds low-cost ramp capability that can be utilized when unexpected ramp demands arise. The following six recommendations seek to improve on these processes.

2012-12: Improve thresholds for uninstructed deviations.

All RTOs have a tolerance band that defines how much a resource's output can vary from the RTO's dispatch instruction before the supplier is penalized for uninstructed deviations. MISO's tolerance band of eight percent of the dispatch instruction (which also requires the deviation occur in four consecutive intervals) is substantially more lenient than those of other RTOs, and effectively increases as the dispatch instruction increases.[37] In fact, many resources can ignore MISO's dispatch instructions altogether and not be deemed to be deviating under this criteria. Additionally, when units perform poorly but do not exceed the tolerance bands, they retain eligibility for PVMWP payments, which will hold them harmless for their poor performance.

To address these concerns, we recommend MISO adopt thresholds based on resources' ramp rates that effectively differentiate poor performance from acceptable performance. We recommend a specific proposal in Section I of the Appendix and depict this in Figure A64. We have also provided MISO with a specification, and it has been presented in more detail at MISO Stakeholder meetings, including the Market Subcommittee. This proposal allows for a multi-interval delay in responding to changes in dispatch to recognize the unique challenges some units in MISO face, but it requires that units overall move at a rate no less than 50 percent of their offered ramp rate.

Resources that are deemed to be deviating under this criteria should incur uninstructed deviation penalties and costs and lose eligibility for PVMWP, ancillary services, and the ramp product. This will improve suppliers' incentives to follow MISO's dispatch signals and will, in turn, improve reliability and lower overall system costs. Additionally, it would be advisable to remove the ramp and headroom on such units from the LAC in order to allow the LAC model to make better recommendations.

<u>Status</u>: MISO generally agrees with this recommendation and originally planned to implement this improvement in 2016. It has been delayed, and we will continue to work with MISO to perform any evaluations necessary to support its filing and implementation. This recommendation is currently included in the Market Roadmap process as Conceptual Design through the end of 2017. MISO is expected to present an analysis of this recommendation to stakeholders in the Fall of 2017.

<u>Next Steps</u>: MISO and the IMM are working to finalize and test the revised rules. Once this is completed and the implications of revised rules are estimated, MISO will need to present the results to its stakeholders and file the revised thresholds at FERC.

2012-16: Re-order MISO's emergency procedures to utilize demand response efficiently.

As noted above, as the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, BTMG, or other forms of demand response. However, these resources cannot be called by MISO before MISO has invoked a number of other

37 This is because the threshold is a fixed percentage of the dispatch instruction. MISO's threshold also includes a minimum of six MW and a maximum of 30 MW.

emergency actions that are costly and adversely impact the market. This recommendation would allow MISO to utilize these resources in a more efficient manner.

Status: This recommendation has been in the evaluation phase for the past four years and a further update is planned for mid-2017. Limited progress has been made to date and we are not aware of a substantive evaluation that has been performed to date.

Next Steps: MISO should perform its evaluation and develop a plan for addressing this recommendation.

2015-4: Enhanced tools and procedures to respond to poor dispatch performance.

In our 2012 report, we recommended changes to the tools used by MISO RGDs. These changes were intended to facilitate RGDs in the identification of poor generator performance. In response to this recommendation, MISO implemented a new tool that calculates and utilizes a simplified version of the metric we had recommended. Based on our continued monitoring of these issues, we conclude that MISO's real-time tools and processes have not been effective in addressing the issues related to poor generator performance, which include: 1) resources responding poorly to set-points (dragging), and 2) resources not responding to set points that are effectively off-control or derated (an "inferred derate"). As we show in this report, these accumulated effects have sizable economic and potential reliability effects.

Therefore, we recommend that MISO improve its tools and procedures for addressing poor generator performance by developing a screen consistent with the uninstructed deviation screen (comparing actual response rate to offered ramp) over a sustained period (significant number of intervals). Recommendation 2012-12 proposes that units failing the uninstructed deviation threshold should not be able to sell ancillary services or the ramp product, or receive PVMWPs. Units performing even more poorly should be placed off-control by the operators.

In addition, we recommend that MISO develop new tools to identify and address cases when State-Estimator residuals (differences between estimated resource output and measured output) are impacting economic dispatch. Based on our investigations over the past two years, the IMM has found that poor responses can be caused when residuals are large relative to the offered ramp rates of resources.

Status: MISO is still evaluating the recommendation to improve the tools to identify inferred derates. In the interim, the IMM will provide real-time indications of inferred derates that are identified by the IMM screens for MISO operators to evaluate. MISO did implement some changes to the UDS inputs and timing that should help reduce dragging caused by the latency of State-Estimator inputs. MISO is also in the process of developing tools to identify State-Estimator errors that are impacting economic dispatch to enable escalation and resolution by EMS engineers, which should be deployed in second quarter of 2017.

Next Steps: MISO will develop and implement the procedures and processes to use the real-time indicators provided by IMM processes. The procedures will include logging the response and outcome of the MISO actions. The IMM will review the logging and make further recommendations as appropriate.

2016-6: Improve the accuracy of the LAC recommendations.

MISO has developed and implemented a Look-Ahead Commitment (LAC) model to optimize the commitment and decommitment of resources that can start in less than three hours. Our evaluation of the LAC results in 2015 and 2016 indicates that the recommendations are not accurate – 80 percent of the LAC-recommended resource commitments are ultimately uneconomic to commit at real-time prices. We also found that operators only adhere to 32 percent of the LAC recommendations, which may be attributable to the inaccuracy of the recommendations. In 2016, one significant source of potential error was identified and MISO is in the process of resolving this issue. However, inaccurate wind output assumptions and other potential issues will also need to be addressed to facilitate accurate LAC results. Hence, we recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop procedures and logging processes to record operator decisions to respond to the LAC recommendations.

Status: This is a new recommendation

2016-7: Improve forecasting incentives for wind resources by modifying deviation thresholds and settlement rules.

DIR wind resources in MISO have a strong incentive to over-forecast their output in real time. Under the current rules for all MISO Resources, Excessive Energy is paid the lower of LMP or the Resource offer. For most conventional resources this is a reasonable outcome and provides reasonable incentives. For wind resources, however, their offers often reflect a Production Tax Credit payment opportunity cost so their offer prices are often in the range of negative $30 per MWh. Hence, the Excessive Energy settlement for wind resources is far more punitive than the Deficient Energy settlement rules. Hence, we recommend MISO make the following two changes to improve the incentives of the wind resources:

- Consider a modified Excessive Energy threshold for wind resources that would allow these resources more latitude to exceed their dispatch levels (i.e., their forecasted output) when it will not cause congestion;
- Modify the Excessive Energy settlement to help balance the Excessive and Deficient Energy settlements that wind resources face associated with forecast errors.

Status: This is a new recommendation

2016-8: Validation of wind resources' forecasts and use results to correct dispatch instructions.

MISO's Tariff requires that a Market Participant's Offers reflect the known physical capabilities and characteristics of Generation Resources, including Forecast Maximum Limits for wind resources that are DIRs. Other than ensuring that forecasts are timely, MISO does not validate the accuracy of wind suppliers' forecast used to develop dispatch instructions for the DIRs. In 2016, certain suppliers' wind forecasts were consistently biased and many were consistently over-forecasted by more than 10 percent. Because the MISO dispatch uses these forecasts as the dispatch maximum, the lack of validation makes the MISO energy dispatch subject to chronic shortfalls related to the overforecasting. Additionally, overforecasting can lead to inaccurate assumed system flows that result in inefficient congestion management.

We recommend that MISO develop appropriate operating procedures, including any necessary Tariff provisions to implement performance standards, in order to validate market participant forecasts. Real-time utilization of the most accurate forecasts will produce more appropriate dispatch instructions for dispatchable wind resources even when a participant's forecast is chronically inaccurate.

Status: This is a new recommendation.

D. Resource Adequacy

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to provide economic signals, together with MISO's energy and ancillary services markets, to facilitate efficient investment and retirement decisions. These economic signals will be increasingly important as planning reserve margins in MISO fall due to low prevailing energy prices, which will increase retirements of uneconomic units.

We have identified a number of critical issues that are undermining the economic signals provided by the MISO planning resource auctions. The impacts of these issues are mitigated to some extent by the fact that regulated utilities serve load in a large portion of MISO. Hence, these regulated utilities may invest in new resources and maintain needed existing units because they receive supplemental revenues through the state regulatory process. However, MISO also relies on a large quantity of supply owned by competitive unregulated companies that rely entirely on MISO's wholesale market price signals to make long-term investment and retirement decisions.

Therefore, it is critically important to respond to the recommendations in this subsection that are intended to establish the efficient price signals necessary to ensure that the market will facilitate investment in the resources over the long term that are necessary to maintain reliability.

2010-14: Improve the modeling of demand in the PRA.

The use of only a minimum requirement and deficiency charges to represent demand in MISO's capacity market results in an implicit vertical demand curve for capacity. This does not reasonably reflect the reliability value of capacity and understates capacity prices as capacity levels fall toward the minimum requirement. This is particularly harmful as large quantities of resources are presently facing the decision to retire in response to the market conditions that have emerged as natural gas prices have fallen.

A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also would produce more efficient and stable capacity prices, particularly as the market moves toward the minimum planning reserve requirement. If this recommendation is not addressed, the MISO markets will not facilitate efficient investment and retirement decisions by participants that will sustain an adequate resource base. Instead, the region will have to rely exclusively on the States requiring their regulated utilities to build new resources.

Understated capacity prices is a particular problem in Competitive Retail Areas (CRAs) where competitive suppliers rely on the market to retain resources MISO needs to ensure reliability. In 2016, MISO developed a proposal to improve the capacity pricing in CRAs that FERC ultimately rejected. We offered an alternative proposal that would have utilized a sloped demand curve to establish prices for competitive suppliers and loads. If a sloped demand curve cannot be implemented for all participants in the PRA, we recommend MISO implement them for the competitive loads and suppliers.

Status: MISO has developed principles governing future market developments, including changes in its resource adequacy provisions and processes. The principles include the objective of facilitating efficient investment, which is consistent with this recommendation. However, there is currently no consensus among the participants and States on how to meet this objective.

Next Steps: MISO should continue to work with its stakeholders and the Organization of MISO States (OMS) to move toward a consensus regarding the economic objectives of the resource adequacy construct. The IMM will support this process by continuing to show the benefits of MISO establishing efficient capacity price signals, which include lowering the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

If a consensus cannot be achieved for improving the representation of demand in the overall market, we recommend that MISO implement capacity market reforms that would establish efficient prices for competitive suppliers and competitive load.

2013-4: Improve alignment of the Planning Reserve Auction and the Attachment Y process governing retirement and suspensions.

Ideally, participants should be able to utilize the PRA to make decisions whether to retire or suspend units, or to return a unit to service from suspension. This allows them to make efficient retirement or suspension decisions. For example, a supplier may submit an offer into the PRA at a price that would cover its going forward cost or the cost that would justify returning from suspension. If such an offer clears, the unit is economic to be in service during the planning year.

Suppliers that have submitted an Attachment Y retirement request currently lose their interconnection rights as of the specified retirement date once the Attachment Y Reliability Study results are received, unless the unit was designated as an SSR Unit. For SSR Units, the interconnection rights are retained until the termination of the SSR agreement. These rules should be modified to allow the broadest possible participation in the PRA, and to allow participants' ultimate decisions to be efficiently facilitated by the PRA. Flexibility will improve market efficiency by reducing inefficient barriers to participating in the PRA.

Status: MISO did modify the use of the provisions in its Tariff, making the provisions available to suspended resources. It was previously available only to new resources and those that were untested because of a catastrophic outage. This change became effective on December 6, 2014. MISO filed Tariff language that allows suspended resources to offer into the PRA. FERC conditionally accepted the revisions on February 12, 2016.

MISO also modified the Attachment Y Notice provisions in its Tariff that apply to resources changing to retirement or suspension status from being in a forced outage. However, the Tariff does not require them to make the change from forced outage to retirement or suspension.

MISO introduced a proposal that eliminates the distinction between suspensions and retirements, which among other changes, increases the flexibility of units with pending retirements to participate in the PRA. MISO acknowledges the difficulties of SSR units being Planning Resources, but has not yet introduced measures to address this into the stakeholder process.

Next Steps: MISO should continue to work through the stakeholder process to prepare Tariff changes that address this recommendation.

2016-9: Qualification of Planning Resources.

Resources with no reasonable expectation of being available during system peak conditions should not qualify as planning resources, since this is fundamentally inconsistent with MISO's planning studies and requirements. Currently, resources on extended forced outages that start after performing their GVTC often qualify as planning resources even though they cannot be restored to service prior the end of the system peak season. In some cases, the asset owners have not decided to repair the resource and prefer to not offer the resource into the PRA. Not only do the current rules allow such resources to be offered, but the supplier would be potentially subject to physical withholding mitigation measures under the current Tariff. To address this issue, we recommend that MISO require such resources to be suspended and not qualified to sell capacity if they will not be operable during the peak season.

Status: This is a new recommendation.

2014-5: Transition to seasonal capacity market procurements.

Both the needs of the system and the available system supply change substantially from one season to the next. This can be recognized by clearing the PRA on a seasonal basis rather than on an annual basis as is currently the case. This would produce the following benefits:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- Resources retiring mid-year would have more flexibility to retire mid-year without having to procure significant replacement capacity to satisfy post-retirement capacity obligations;
- The qualification of resources with extended outages can better match their availability; and
- The duration of SSR contracts can be matched with planning seasons, which removes a barrier for SSR Units to serve as Planning Resources.

Status: This issue was recently reintroduced into the stakeholder process where MISO proposed a two-season proposal. Use of two seasons does not capture the opportunity to achieve savings that could be achieved by scheduling efficient economic outages during the shoulder months and only reduces the benefits of a seasonal structure.

Next Steps: To capture the benefits described above, we recommend that MISO evaluate the costs and benefits of implementing four seasonal requirements rather than two seasons.

2014-6: Define local resource zones primarily based on transmission constraints and local reliability requirements.

Currently, a local resource zone cannot be smaller than an entire LBA. In some cases, however, capacity is needed in certain load pockets within an LBA. For example, NCAs in MISO South have substantial capacity needs to satisfy local reliability requirements. In neither case, however, can the capacity prices in the PRA reflect the need for capacity in these areas and the limited transmission capability into the areas because the current zones are much larger. Therefore, we recommend that MISO adopt procedures for defining capacity zones that would allow the zones to be determined by transmission constraints and other local reliability needs rather than the historic boundaries that are unrelated to the transmission network.

Status: MISO has engaged its stakeholders in a discussion of the criteria for establishing zones based primarily on transmission constraints, but a proposal has not been finalized.

Next Steps: MISO should continue to discuss this recommendation with stakeholders with the goal of adopting procedures for defining capacity zones that would allow the zones to be determined by transmission constraints and other local reliability needs, rather than the historic boundaries that are unrelated to the transmission network.

2015-5: Implement firm capacity delivery procedures with PJM.

In June 2016, approximately 2 GW of capacity in MISO began pseudo-tying to PJM because it was sold in the PJM capacity market. In June 2017, additional resources will begin selling capacity to PJM and may also pseudo-tie to PJM. Under its Capacity Performance construct, PJM completed its five-year transition period and now requires external resources to pseudo-tie to PJM beginning with the Base Residual Auction in May 2017 for the 2020/2021 planning year. While pseudo-tying may appear to achieve better comparability between PJM's external and internal capacity resources, it will impose substantial costs on the joint region by reducing dispatch efficiency and reliability. Additionally, the reduced dispatch efficiency will impose substantial potential cost exposure on both RTOs as the number of market-to-market constraints has and will continue to increase substantially.

We have developed proposed "Capacity Delivery Procedures" that would facilitate the delivery of MISO capacity to PJM without incurring the adverse effects of pseudo-tying the resources. We recommend that MISO work with PJM to develop these procedures, or similar procedures, to serve as an alternative to pseudo-tying MISO's resources to PJM. In nearly all respects, these provisions can be designed to impose requirements on capacity resources in MISO that are comparable to PJM's internal capacity resources, without compromising dispatch efficiency or degrading local reliability. In fact, these provisions would increase PJM's access to the external capacity and make its delivery to PJM more reliable.

Status: In 2016, MISO's Pseudo-Tie Issues Task Team evaluated this recommendation and supported it with minor modifications. MISO has engaged PJM in a series of discussions and proposed a variant of Capacity Delivery Procedures to the MISO-PJM Joint and Common Market, but PJM has since indicated they cannot support it.

However, recognizing the problems caused by the pseudo-ties, both PJM and MISO have filed proposed tariff changes that will restrict their approval in the future, which will also unreasonably restrict capacity trading. Therefore, we filed a 206 complaint against PJM to eliminate the pseudo-tying requirement and replace it with a reasonable alternative, which could be the Capacity Delivery Procedures.

Next Steps: The next steps on this recommendation will likely depend on FERC's Order on the RTOs' Section 205 filings and our Section 206 complaint. MISO, in response to PJM's 205 filing, has requested that FERC Order a Technical Conference to include a broad range of issues, including potential alternatives to meeting PJM's objectives.

2015-6: Improve the modeling of transmission constraints in the PRA.

MISO employs a relatively simple representation of transmission limits in the PRA, generally modeling only aggregate import and export limits to and from each capacity zone. Additionally, MISO accommodates the transfer limitations between the MISO South and Midwest regions as an additional constraint. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified import or export limits for one or more zones. Additionally, MISO assumes power flows associated with importing capacity from external resources that is not consistent with where the resources are located, and also not consistent with how such imports will affect the scheduled flows over the RDT. Ultimately, these issues lead to sub-optimal capacity procurements and locational prices.

Hence, we recommend that MISO add the RDT and transmission constraints to its auction model as needed to address potential simultaneous feasibility issues and to reflect the differing impact of zonal resources on regional constraints. This should include defining external capacity zones consistent with the interfaces MISO uses to operate the system in its day-ahead and real-time market. Likewise, MISO should model the RDT constraint consistent with how it is modeled in the day-ahead and real-time markets, which is determined by the settlement agreement between MISO, SPP, and its other neighbors. For both the RDT and other relevant internal constraints, MISO should establish shift factors that define how each internal and external zone affects each constraint. Ultimately, this is a very simple version of a constrained optimal dispatch (much simpler than MISO's energy market). It would allow MISO to represent all regional constraints that may be affected by multiple local zones (e.g., the way the three zones in MISO South affect the south-to-north transfer constraint) and activate any constraints that may arise in its simultaneous feasibility assessment.

Status: MISO recently reintroduced a proposal to partially address this recommendation by changing how it defines and sets prices for external zones.

Next Steps: MISO will likely need to evaluate the software and other implications of implementing an efficient locational framework in the PRA. If it begins by modeling only the RDT, it should endeavor to do so in a manner that will facilitate modeling additional constraints in the future.

2015-7: Improve the physical withholding mitigation measures for the PRA by addressing uneconomic retirements.

As capacity margins fall in MISO, the market will become more vulnerable to physical withholding. However, the MISO tariff is not fully effective in mitigating clear exercises of market power in the PRA through physical withholding. In particular, it is not clear that retiring a unit that is clearly economic to continue operating would be considered physical withholding and subject to MISO's mitigation measures.

Therefore, we recommend that MISO improve the physical withholding mitigation measures for the PRA by clarifying how they would be applied to uneconomic retirements.

Status: MISO has not expressed support for addressing uneconomic retirements. This recommendation previously also included applying physical withholding mitigation jointly on affiliated market participants rather than on each participant independently. This change was filed by MISO and approved by FERC in early 2017.

Next Steps: Given that most other RTOs have addressed this form of potential market power abuse, MISO should justify why this is not a risk in the MISO market.

2015-8: Improve the limit on the transfer constraint between MISO South and Midwest in the PRA.

MISO models a regional transfer constraint between the MISO South and Midwest regions in the PRA that is intended to represent the amount of capacity located in the South that can be relied upon to address contingencies in the Midwest and vice versa. Early in 2016, MISO entered into a settlement agreement whereby MISO has the authority to schedule transfers up to 3,000 MW from MISO Midwest to South and 2,500 MW from MISO South to Midwest. However, MISO neighbors may declare an emergency and request that MISO temporarily reduce its interregional transfers to a lower level. This should rarely occur, because MISO may coordinate the flows on individual constraints that are affected by its transfers through its Market-to-Market coordination (with SPP and PJM) or through the TLR process (with other control area operators). Nonetheless, these caps on the transfers do not represent firm transfer capabilities.

For the most recent PRA, MISO enforced a MISO South to Midwest transfer limit of 1,500 MW. It calculated this value by starting with the full transfer limit and subtracting firm transmission rights that source in MISO South and sink in external areas that interconnect with MISO Midwest. In other words, it assumed that participants that hold firm external transmission rights (e.g., from a MISO South location to PJM) can occupy the transfer constraint.[38] This approach is not reasonable because holders of firm transmission rights cannot prevent MISO from

38 In a similar fashion, MISO established a 2,794 MW transfer limit from MISO Midwest to MISO South, but it did not bind in the most recent PRA.

transferring power over the transfer interface between the regions. These participants simply have the authority to schedule a firm export, which MISO will support with its dispatch – the real-time dispatch will determine which generation will ramp up to support the export.

Hence, we recommend that the transfer limit assumed in the PRA equal the total transfer limit minus a derating factor that represents the probability that MISO neighbors will request a derating. If this probability is deemed to be five percent, then the south-to-north transfer limit would equal 2375 MW (2500 MW * 0.95). This recommendation would have had a substantial effect on the clearing prices in most of the Midwest zones in the PRA for the 2016/2017 planning year. This recommendation does not extend to Regional Pseudo-Tie Flow, as defined in the Settlement Agreement, which will pass through the regional transfer constraint.

Status: In MISO's compliance filing associated with the CMTC complaint, MISO codified their current methodology, which does not address this recommendation. We filed a protest on this methodology because it is inconsistent with MISO's system operations.

Next Steps: The next steps will depend on FERC's order on MISO's compliance filing.

E. Prior Recommendations Not Included in the 2016 Report

In addition to the progress made on a some of recommendations discussed above, MISO addressed several past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions in 2015 and early 2016. These recommendations are discussed below, along with unresolved recommendations that are not included in this year's report.

Recommendations Addressed by MISO

2012-2: Implement a five-minute real-time settlement for generation.

MISO clears the real-time market in five-minute intervals and sends corresponding dispatch instructions to generators on a five-minute basis. However, it settles generation on an hourly basis. This can create inconsistencies between the dispatch signal and the hourly prices that can cause generators to have the incentive to not follow the dispatch signal or to simply be inflexible. This inconsistency is only partially addressed by the PVMWPs. Implementing this recommendation will improve the incentives for generators to follow dispatch instructions and provide more flexibility.

Status: This recommendation was originally proposed in our 2012 State of the Market Report. FERC issued Order 825 on June 16, 2016 that requires each RTO/ISO to align settlement and dispatch intervals in the real-time markets. In January 2017, MISO made a compliance filing that proposes to settle generation and operating reserves on 5-minute intervals. Interchange transactions would continue to settle at 15-minute intervals and load would continue to settle hourly. FERC approved MISO's filing in early May 2017. MISO projects completion of its Settlement System upgrade in the third quarter of 2017, to be followed by the planned implementation of this recommendation in the first quarter of 2018.

2012-9: Allow the definition of a "dynamic NCA" that is utilized when network conditions create substantial market power.

MISO is preparing a tariff filing to address this recommendation. It is intended to improve the effectiveness of the mitigation measures at addressing market power caused by transitory conditions (transmission or generation outages) that create severely-constrained areas. The tariff revisions would expand Module D mitigation provisions to allow temporary "dynamic" NCAs to be defined while the conditions persist and would employ a fixed conduct and impact threshold of $25 per MWh.

<u>Status and Resolution</u>: The IMM will support MISO's tariff filing and implementation of the dynamic NCA. We anticipate MISO making a FERC filing in the 2nd quarter of 2017 and implementation in the third quarter 2017, pending FERC's approval.

2015-3: Model VLR requirements in the Day-Ahead market.

Most of the VLR requirements in MISO South are satisfied through commitments made prior to the day-ahead market. In 2015 and 2016, MISO has continued to improve the day-ahead VLR commitment process and related RSG costs have declined sharply. While we may revisit this recommendation in the future to improve commitment of units with long start times, current results do not warrant prioritizing this recommendation.

<u>Status:</u> We will revisit this recommendation in the future if warranted by market results. In addition, this recommendation will be overtaken by the separate recommendation on modeling the regional 30-minute reserve requirements (See 2014-2).

Unresolved Recommendations Not Included in 2016 Report

2012-3: Remove external congestion from interface prices.

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it generally duplicates the congestion pricing by the external system operator. For example, PJM already includes the congestion effects of external transactions in its interface pricing, so when MISO includes these same effects in its interface prices, the resulting congestion settlements are redundant and inefficient. The excessive settlement of congestion in the interface prices produces the following adverse results:

- The excess payments can result in higher negative excess congestion funds, market-to-market costs, or FTR underfunding.

- The excess payments can motivate participants to schedule inefficient transactions, while the excess charges can discourage efficient transactions.

The excess payments are not limited to market-to-market constraints in PJM. They also occur on constraints in other areas for which MISO activates constraints when the other system operator calls a TLR. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of the interface prices associated with the external constraints.

Status: This recommendation was originally made in our *2012 State of the Market Report*, although it was previously raised in our *2011 State of the Market Report.* Over the past five years, we worked with MISO, PJM, and stakeholders through the Joint and Common Market Stakeholder group to achieve a consensus on the problem and potential solution. While a long-term solution is limited by the scope of PJM's current transmission model, the RTOs have been evaluating short-term alternatives. MISO has made the decision to adopt PJM's proposed solution to both use a common interface definition. Unfortunately, our analysis to date has shown that this will provide less efficient, more volatile scheduling incentives than the preferred short-term and long-term solution, which is for MISO to remove all external congestion from its interface prices. We will monitor and evaluate the efficiency of the interface prices following the June 2017 implemention of the common interface. We also continue to encourage MISO to complete any software changes necessary to remove external congestion from its interface prices, as these changes are necessary to remove other external constraints in other adjacent areas.

2010-11: Include expected deployment costs when selecting spinning reserves.

The MISO operating reserve market does not consider resources' potential deployment costs when it procures reserves. This caused MISO to routinely schedule spinning reserves on resources that were very expensive to deploy, resulting in millions of dollars of inefficient guarantee payments when they were deployed. Including the expected value of these costs in the procurement process would have resulted in more efficient reserve scheduling. Hence, we recommended that MISO address this issue in one of two ways, either by:

- Eliminating the guarantee payment made to spinning reserve providers when they are deployed; or
- Calculating the expected value of the out-of-market deployment cost for each unit, and adding that expected cost to each unit's spinning reserve offer.

Status: This recommendation was originally made in the *2010 State of the Market Report.* In June 2016, the IMM and MISO staff presented these alternatives to the MISO Market Subcommittee. The first alternative would compel the resource owner to include the expected deployment cost in its offer so these costs would be included in the selection and pricing of spinning reserves. The second alternative would explicitly incorporate the expected deployment costs (as estimated by MISO) in the selection and pricing of spinning reserves. The IMM and MISO staff did an additional analysis in 2016 and found that because certain units are no longer participating in the market, the impact of this issue has declined significantly.

2014-1: Modify the allocation of FTR shortfalls in order to fully fund MISO's FTRs.

Currently, all funding shortfalls are allocated to the FTR holders, which can result in funding that is less than 100 percent. This diminishes the value of the FTRs as congestion hedges and lowers their prices. To the extent that the shortfall levels are uncertain, the prices for the FTRs are likely to fall by more than the shortfall amount. Ultimately, this harms MISO's transmission customers by reducing the allocation of FTR revenues to the transmission customers.

Therefore, we recommended that MISO guarantee full funding of its FTRs by allocating the shortfall directly to transmission customers. Customers would receive higher FTR revenues as the prices for the FTRs rise, which should more than offset this allocation. We also recommended that some or all of the shortfalls that are due to transmission outages should be allocated to the transmission owner to improve their incentives to schedule outages more efficiently, i.e., to limit their duration and take the outages in periods that are least likely to cause significant congestion costs.

Status: MISO's initial assessment was that this recommendation could improve economic incentives for scheduling outages. MISO concluded that additional options to improve the economic incentives for outage scheduling should be explored. However, MISO's initial assessment also concluded that modifying the allocation of FTR shortfalls is not a high priority at this time because funding levels are relatively high. The MISO Roadmap status indicates that no action is planned and there is no specific date for a status update. Given MISO's assessment and the fact that FTR funding levels have been high, we are suspending this recommendation and will reconsider it in the future.

2017 OMS MISO Survey Results

Furthering our joint commitment to regional resource assessment and transparency in the MISO region, OMS and MISO are pleased to announce the results of the 2017 OMS MISO Survey

July 2017

The 2017 OMS MISO survey projects sufficient resources to manage resource adequacy risk

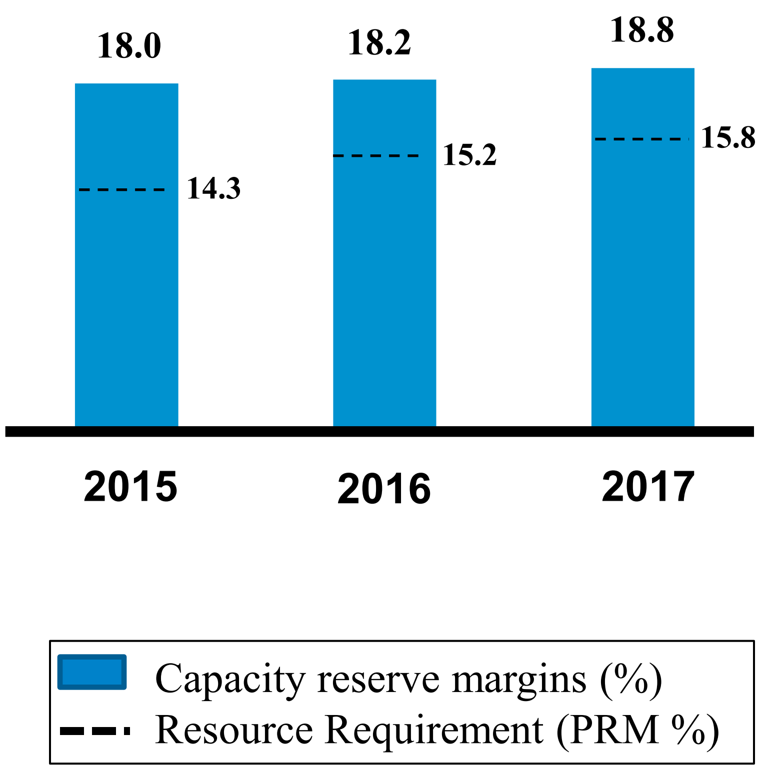
- In 2018, changes in resource commitment and decreased demand lead to a regional surplus
  - The region is projected to have 2.7 GW to 4.8 GW resources in excess of the regional requirement, based on responses from over 96% of MISO load
- Decreases in demand forecast leads to a lower resource adequacy risk than previously projected
  - 2018 summer peak forecasts decreased 2.5 GWs from 2017 projections
  - Regional 5 year growth rate is 0.5%, down from 0.8% last year
- Beyond 2018, continued focus on load growth variations and generation retirements will reduce uncertainty in future resource adequacy assessments

Understanding Resource Adequacy Requirements

- Load serving entities within each zone must have sufficient resources to meet load and required reserves
- Surplus resources may be used by load serving entities with resource shortages to meet reserve requirements

Planning Reserve Margins capture the risks in the load and generation on the system

Projected Reserve Margins and Requirements (% ICAP)

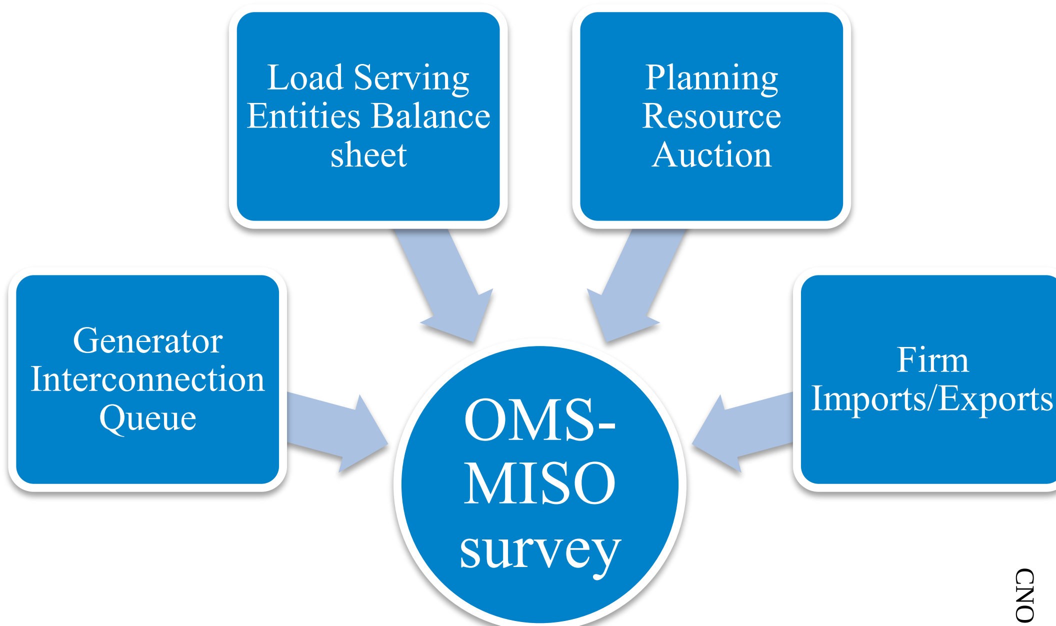


- Planning Reserve Margins show how much capacity is needed as a percentage above load, to maintain resource adequacy

- The percent resource requirements may be **higher** when
  - Fleet forced outage rate is **higher**
  - Load volatility is **higher**
  - Load forecasts are **lower**

What’s in the survey?

- OMS-MISO survey responses
  - Insight into confidence around availability of resources
- Load data
- All generation within MISO, including merchant resources, considered
- External imports, exports, and inter-zonal transfers accounted for



Illustrative OMS MISO Data Request

Existing Resources

									2018*	2018**	…	2026	2026
LSE	LBA	Actual LRZ Resource Location	Physical Location (City, State)	MECT Planning Resource Name	Fuel Type of Planning Resource	Planning Resource Type	Corrected ICAP (UCAP Renewables)	UCAP MW	YES/NO	Factor	…	YES/NO	Factor
TEST_LSE		Zone X	TBD	Example unit 1	Coal	Gen	165.0	159.2	Yes	H	…	No	H
TEST_LSE		Zone X	TBD	Example unit 2	Gas	Gen	153.0	145.9	Yes	H	…	Yes	H
TEST_LSE		Zone X	TBD	Example unit 3	Diesel	BTMG	26.5	21.3	Yes	H	…	Yes	H
TEST_LSE		Zone X	TBD	Example unit 4		DRR	36.8	36.8	Yes	H	…	Yes	L
TEST_LSE		Zone X	TBD	Example unit 5	Gas	ER	88.6	84.7	Yes	H	…	No	L

New Resources

LSE	Actual LRZ Resource Location	Project Name	Tier 1, Tier 2, Tier 3	Resource Type	Location	ICAP (Intermittent Non- Wind & Solar UCAP)	MISO Class EFORd	UCAP MW	Year Expected for Capacity Credit	GIQ - Project Number
TEST_LSE	Zone X	New Project	Tier 1	CC		500	0.00378	498.1	2020	JXXX
TEST_LSE	Zone X	New Project II	Tier 3	CC		250	0.00378	249.1	2021	

* Resource Availability
** Certainty Factor

Illustrative OMS MISO Data Request

Internal MISO Transfers

									2018	2018	…	2026	2026
LSE	LBA	Actual LRZ Resource is Physically Located	MECT Contract Name	MECT Planning Resource Name	Planning Resource Fuel Type	LRZ Internal Transfer Type (In/out)	Corrected ICAP (UCAP Renewables)	UCAP MW	YES/ NO	Factor	…	YES/ NO	Factor
TEST_LSE A		Zone X	Contract with LSE B and LSE A	Unit 1	Coal	LRZ Internal Transfer- Out	287.7	285.3	Yes	H	…	Yes	H
TEST_LSE A		Zone X	Capacity Deal with LSE C and LSE A	Unit 2	Coal	LRZ Internal Transfer- In	276.7	274.4	Yes	H	…	Yes	H
TEST_LSE B		Zone Y	Contract with LSE B and LSE A	Unit 1	Coal	LRZ Internal Transfer- In	287.7	285.3	Yes	H	…	Yes	H
TEST_LSE C		Zone Z	Capacity Deal with LSE C and LSE A	Unit 2	Coal	LRZ Internal Transfer- Out	276.7	274.4	Yes	H	…	Yes	H

Full Responsibility Transactions

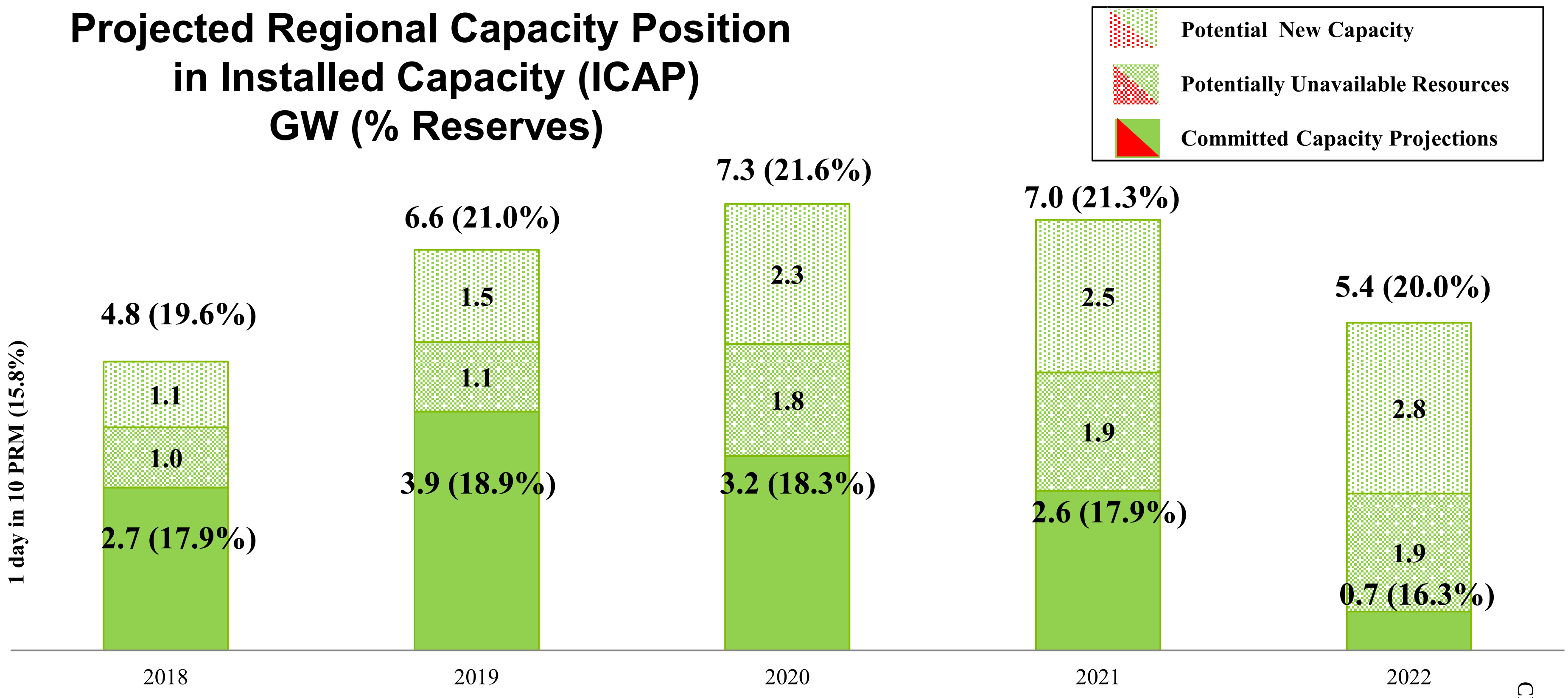
						2018	2018	...	2026	2026
LSE	LRZ	MECT Contract Name	Sale or Purchase	Counterparty	FRT MW Sales (-) Purchase (+)	YES/NO	Factor	...	YES/NO	Factor
TEST_LSE A	Zone X	LSE A to LSE C PY16-17	Sale	TEST_LSE C	-50	Yes	H	...	Yes	H
TEST_LSE C	Zone X	LSE A to LSE C PY 16-17	Purchase	TEST_LSE A	50	Yes	H	...	Yes	H

Understanding Resource Projections

- **Committed Capacity Projections** include resources committed to serving MISO load
  - Resources within the rate base of MISO utilities
  - New generators with signed interconnection agreements
  - External resources with firm contracts to MISO load
  - Non-rate base units without announced retirements or commitments to non-MISO load
- **Potential Capacity Projections** include resources that may be available to serve MISO load but do not have firm commitments to do so
  - Potential retirements or suspensions
  - 35% of new resources in the Definitive Planning Phase (DPP) of the MISO queue
- **Unavailable resources** are not included in the survey totals
  - Resources with firm commitments to non-MISO load
  - Resources with finalized retirements or suspensions
  - Potential new generators without a signed Generator Interconnection Agreement or generators which have not entered the DPP phase of the queue

Existing resources, potential retirements, and new resources create a range of resource balances

Projected Regional Capacity Position in Installed Capacity (ICAP) GW (% Reserves)



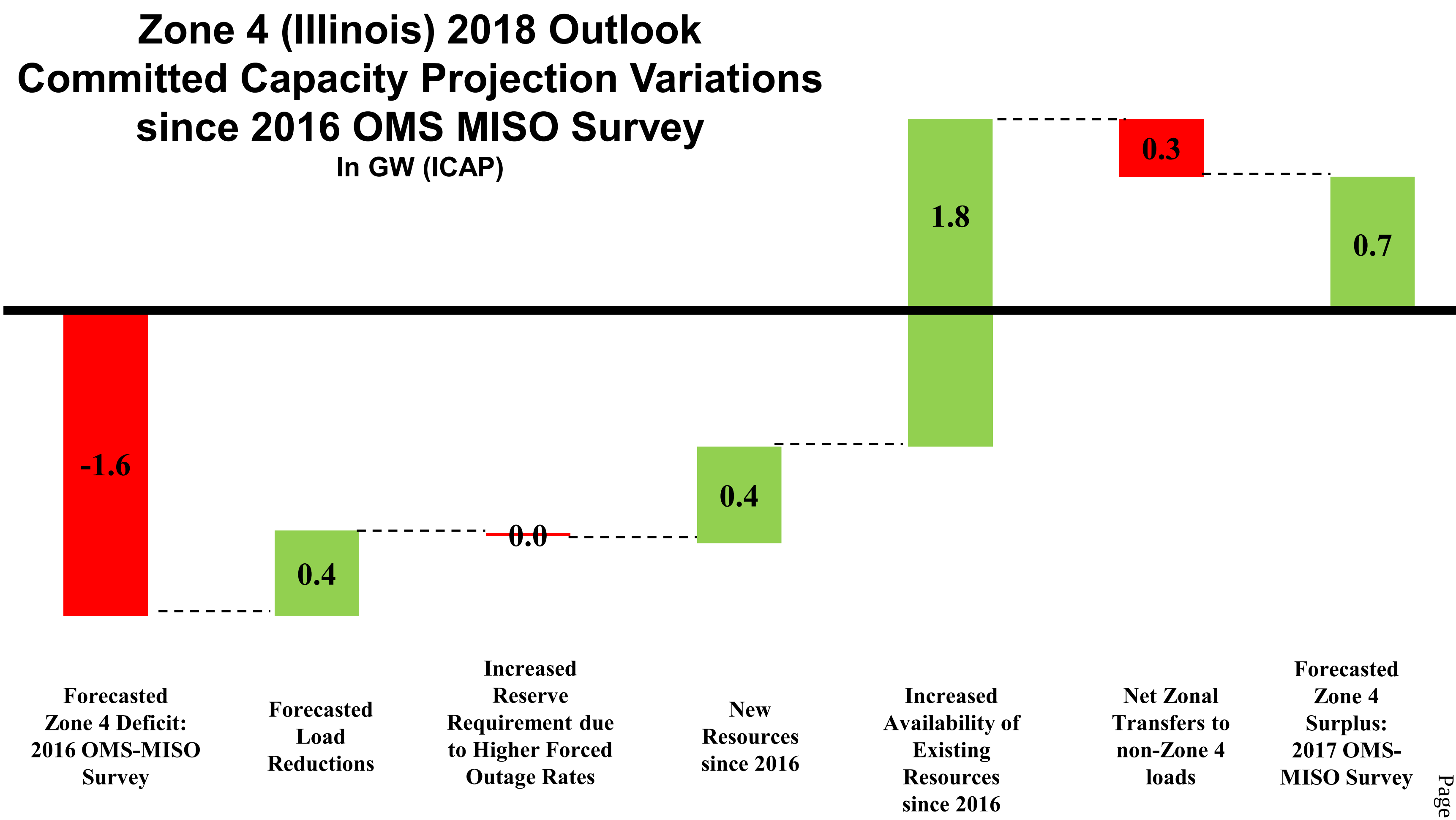
- Regional outlook includes projected constraints on capacity, including Capacity Export Limits and the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities and state commissions.
- **Potential New Capacity** represents 35% of the capacity in the final stage of the MISO Generator Interconnection queue, as of May 11, 2017.
- **Potentially Unavailable Resources** includes potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint

Regional capacity balances increased largely due to lower demand forecasts

Regional 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)

New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Decreased availability results from new retirements and more binding transfer limitations
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load

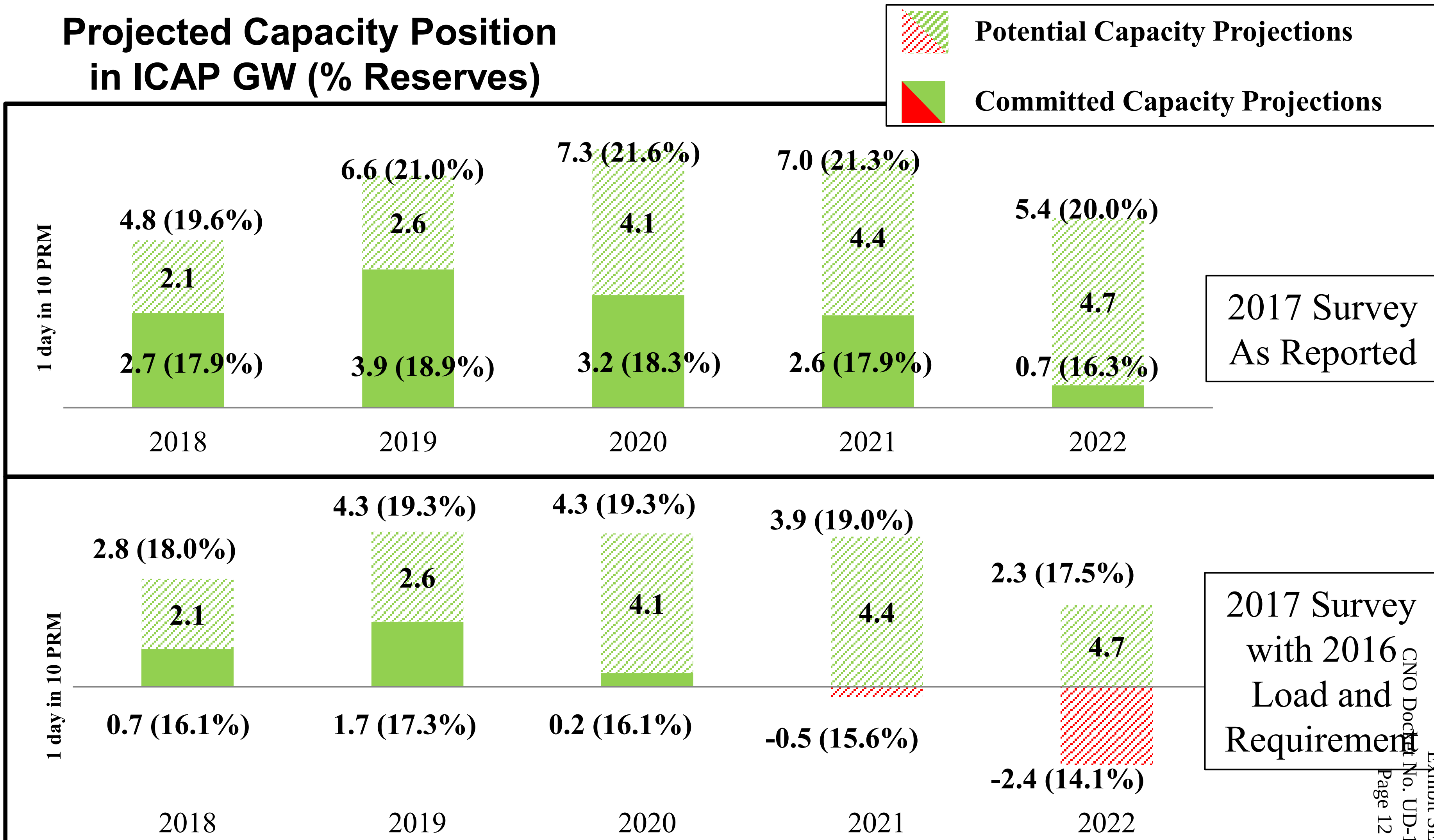
Activity in Illinois resulted in much of the year-over-year regional change; continued action is required to achieve forecasted balances



<u>**New resources**</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources
<u>**Increased availability**</u> results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

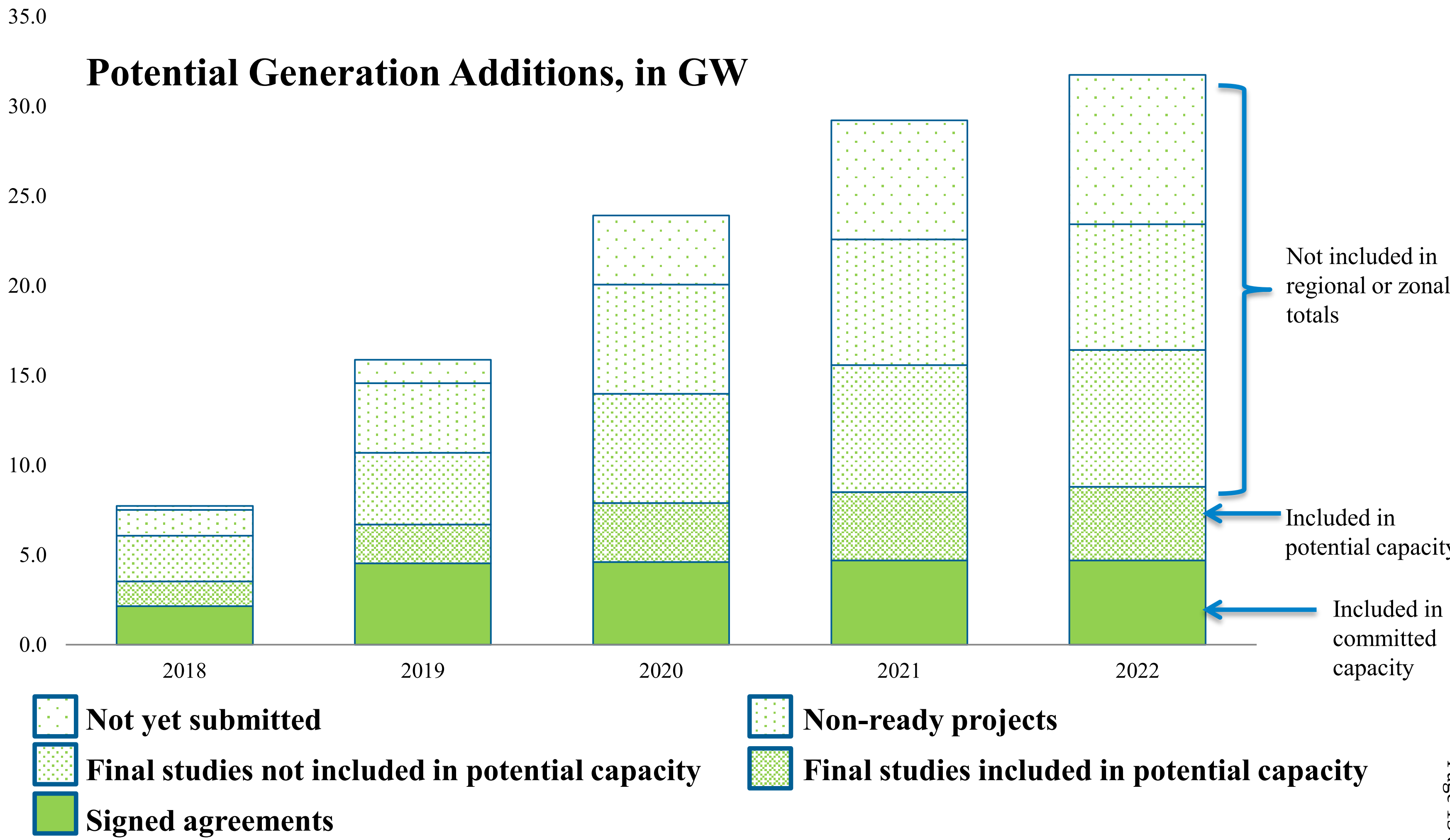
Demand forecast variation creates risk for forward-looking resource adequacy projections

Projected Capacity Position in ICAP GW (% Reserves)



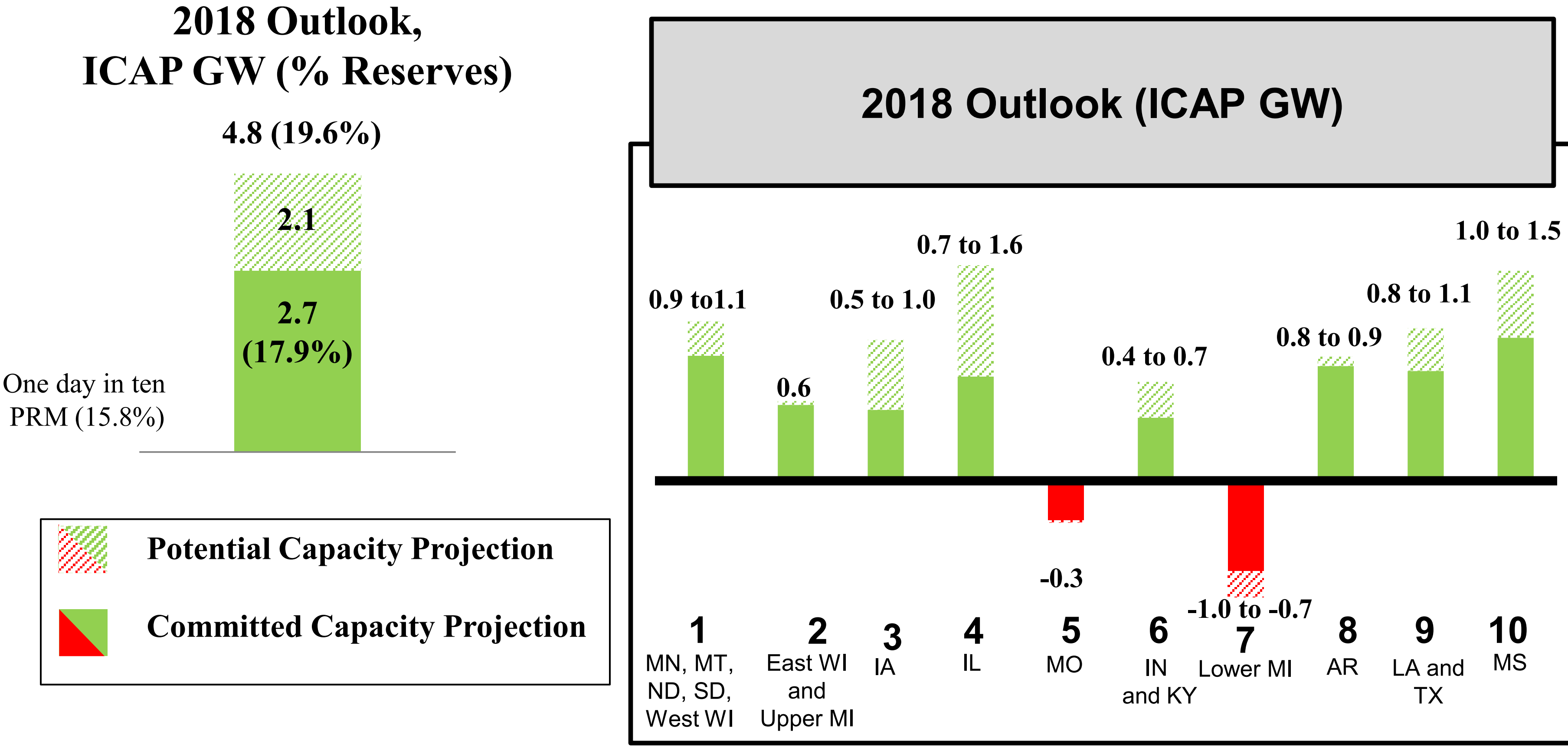
<u>Potential Capacity</u> includes potential new capacity and potentially unavailable resources

Future resource ranges will shift as planned generation interconnections are firmed up



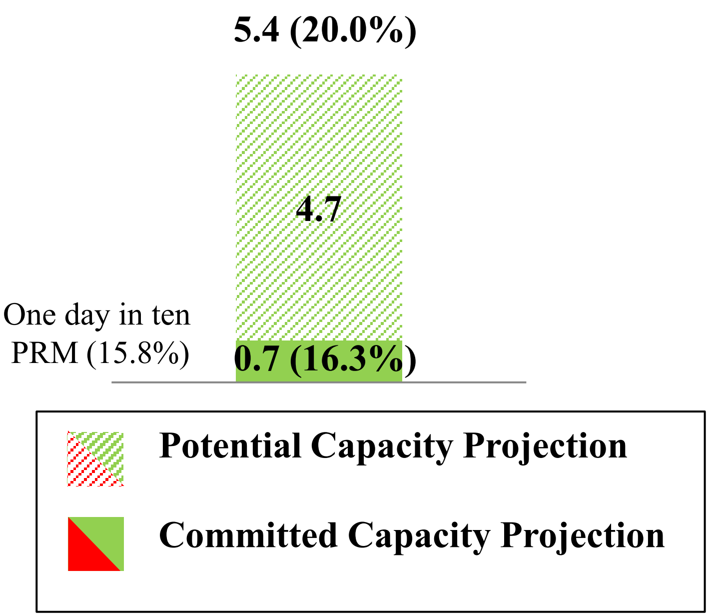
Wind and solar resources are represented at their expected capacity credit
<u>Non-ready projects</u> will be deemed withdrawn, as of June 15th, with an option to move to final studies

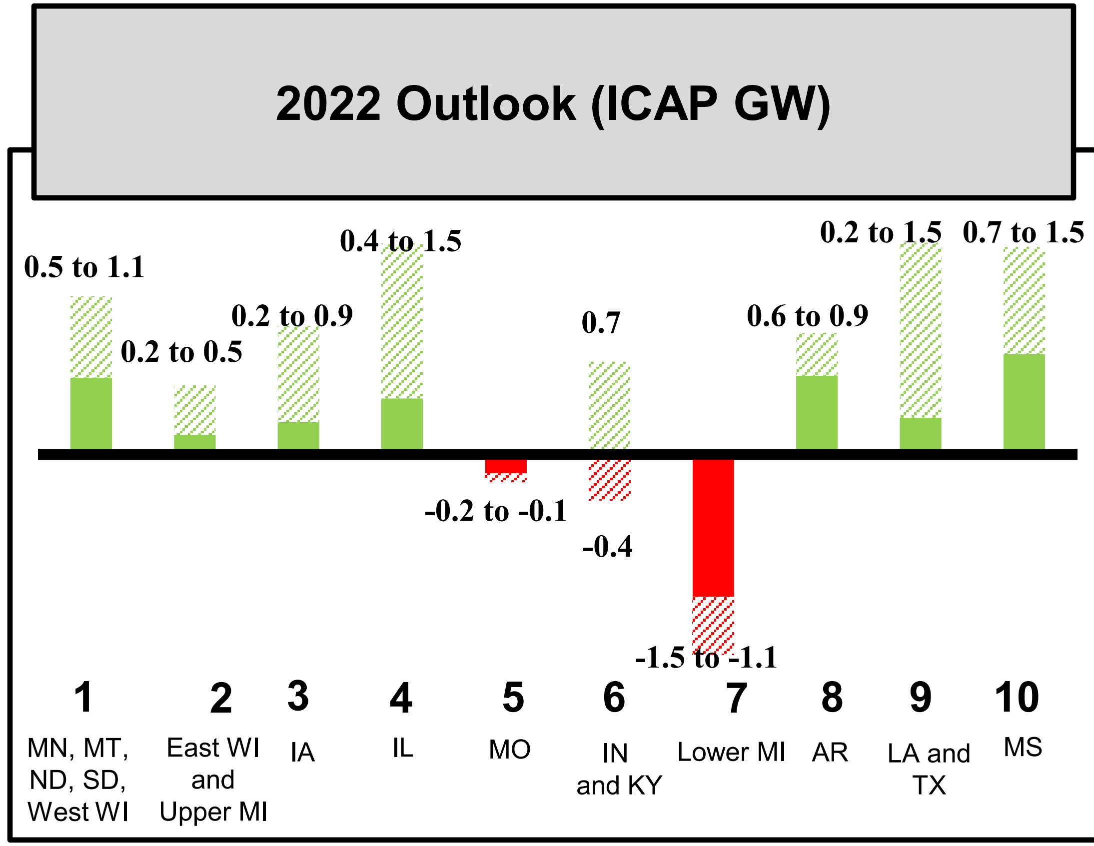
In 2018, regional surpluses are sufficient to cover areas with resource deficits



- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zone 1 were limited by the zone's Capacity Export Limit to 0.6 GW
- Results include load, but not identified resources, from some non-jurisdictional load in Zone 5
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint to 1.2 GW

Continued focus on load growth variations and generation retirements will reduce uncertainty around future resource adequacy assessments





- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Results include load, but not identified resources, from some non-jurisdictional load in Zone 5
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint to 1.5 GW in committed capacity projections and 1.9 GW in potential capacity projections

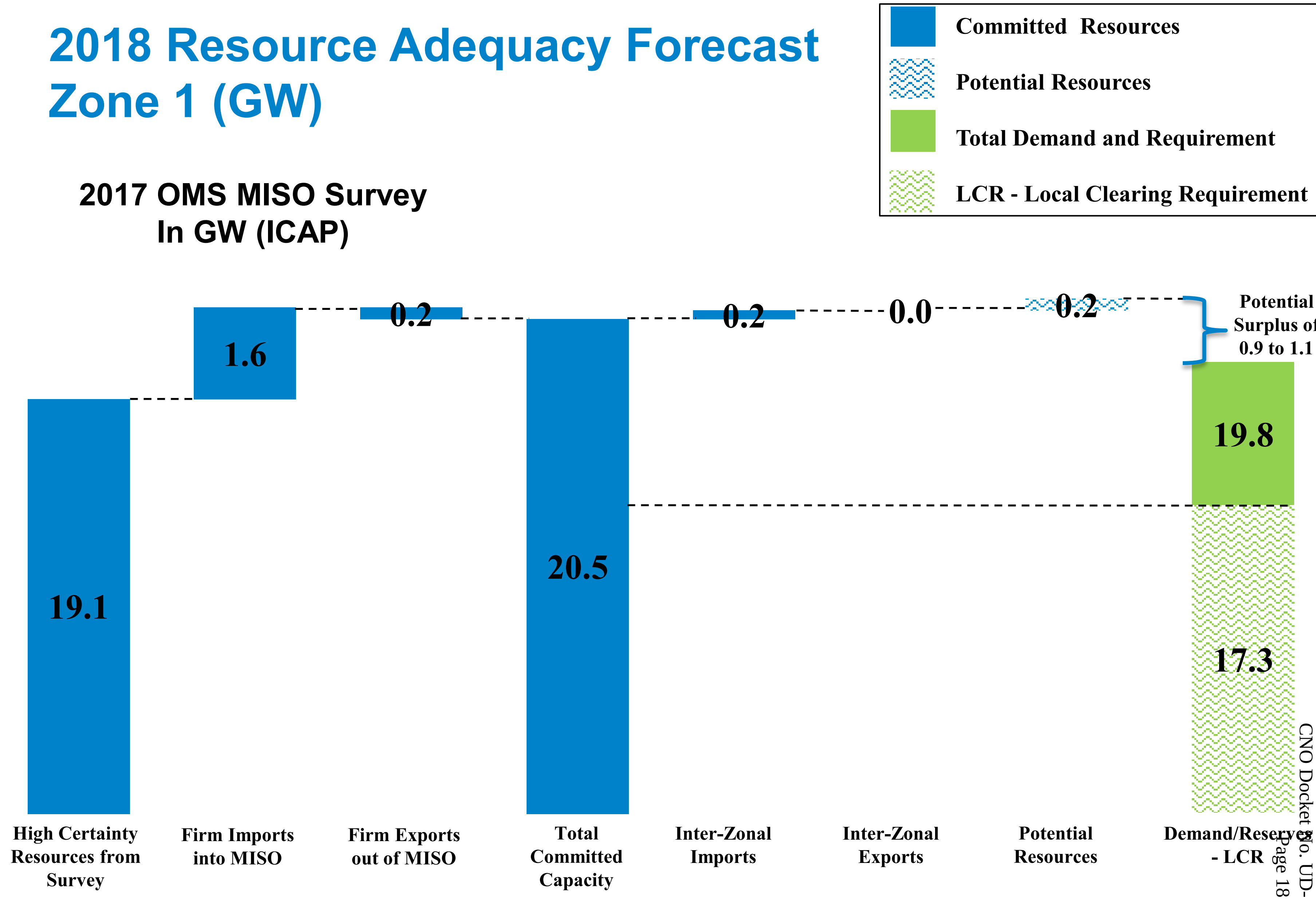
Appendix

Definitions

- Committed Capacity Resources
  - High Certainty From Survey
    - Resources within the MISO footprint committed to serving demand, based on survey responses
    - Includes resources with signed Interconnection Agreements
  - Firm Imports into MISO
    - Resources located outside of MISO committed to serving demand in MISO and included in zonal capacity totals
  - Firm Exports out of MISO
    - Resources located inside of MISO committed to serving demand outside MISO and excluded from zonal capacity totals
- Total Committed Capacity
  - Total capacity available to serve demand in the given Planning Year. This will not include Potential resources
- Potential Capacity Resources
  - Resources have some indication of not being available to serve demand and classified as 'low certainty' by survey responses
  - An example of a "low" certainty resource could be a resource that has submitted an attachment Y2
  - 35% of all resources in the final stages of the Definitive Planning Phase of the MISO Interconnection Queue
- Inter-zonal Imports / Exports
  - Resources from one zone within MISO which were designated as serving load in a different MISO zone by survey responses
- Demand/Reserves
  - Projected demand plus the MISO Planning Reserve Margin Requirement of 15.8%
  - A portion of this requirement may be served by capacity located outside of the zone

2018 Resource Adequacy Forecast Zone 1 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 1 (GW)

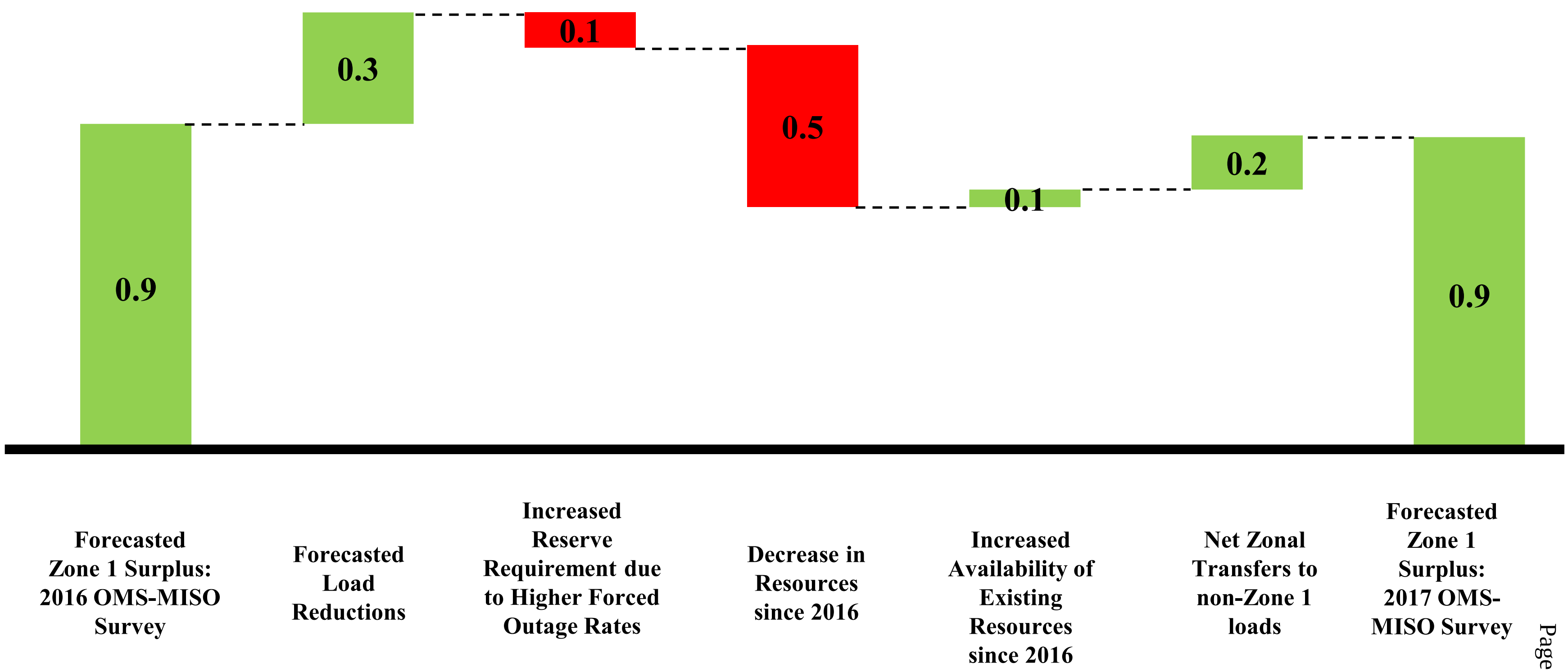
2017 OMS MISO Survey

Values In GW (ICAP)

Zone 1	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	19.3	19.3	19.2	A
Firm Imports into MISO	1.6	1.6	1.7	B
Firm Exports out of MISO	0.2	0.2	0.2	C
Total High Certainty Capacity	**20.7**	**20.6**	**20.7**	D = (A+B)-C
Inter-Zonal Imports	0.3	0.3	0.4	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**20.0**	**20.2**	**20.3**	G
Firm Capacity Position	**1.0**	**0.7**	**0.8**	H =(D+E-F)-G
Low Certainty Resources	0.4	0.6	0.6	I
Potential Capacity Surplus/Deficit	**1.4**	**1.3**	**1.4**	J =(H+I)

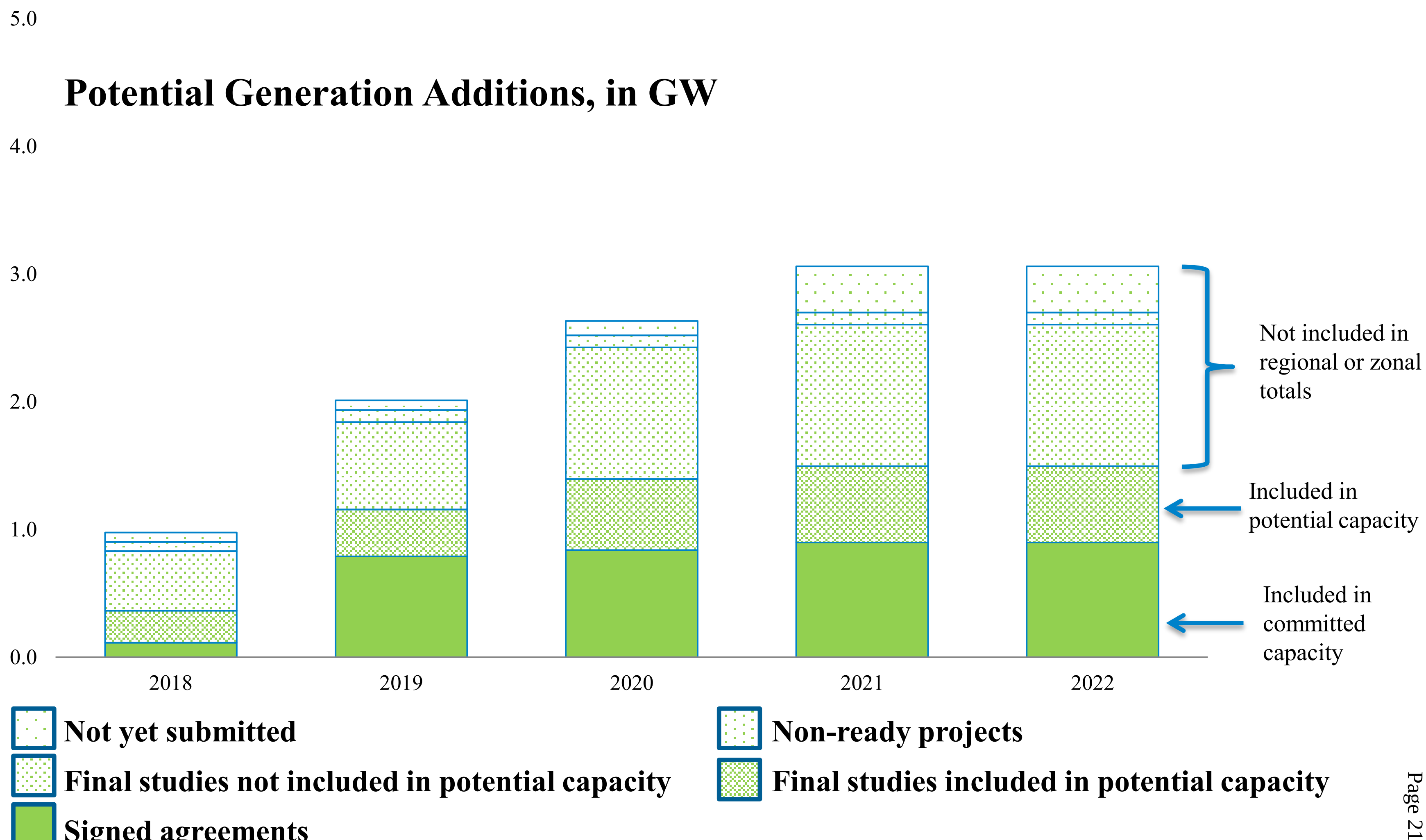
2016 vs 2017 OMS MISO Survey Results
Zone 1

Zone 1 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

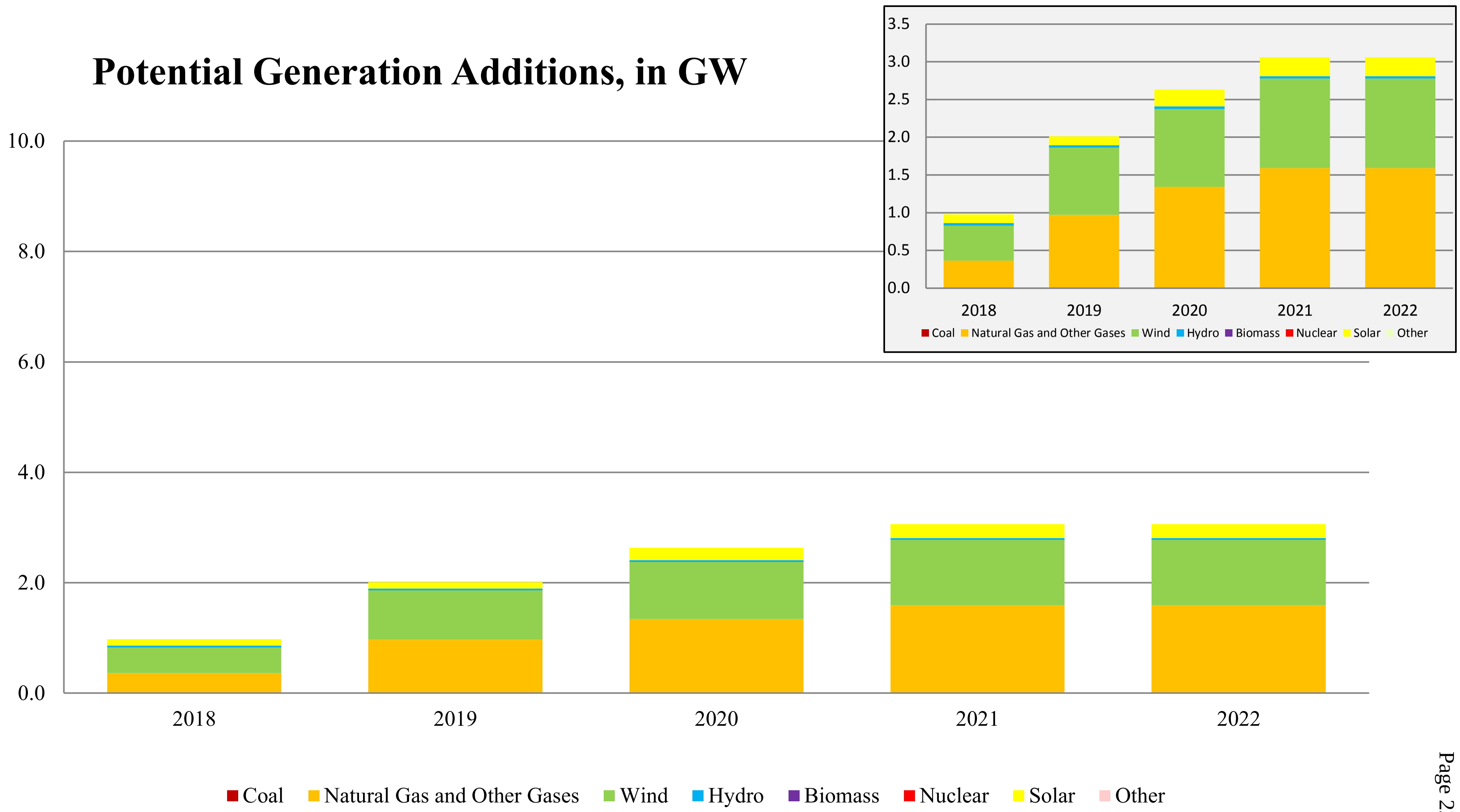
Zone 1 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

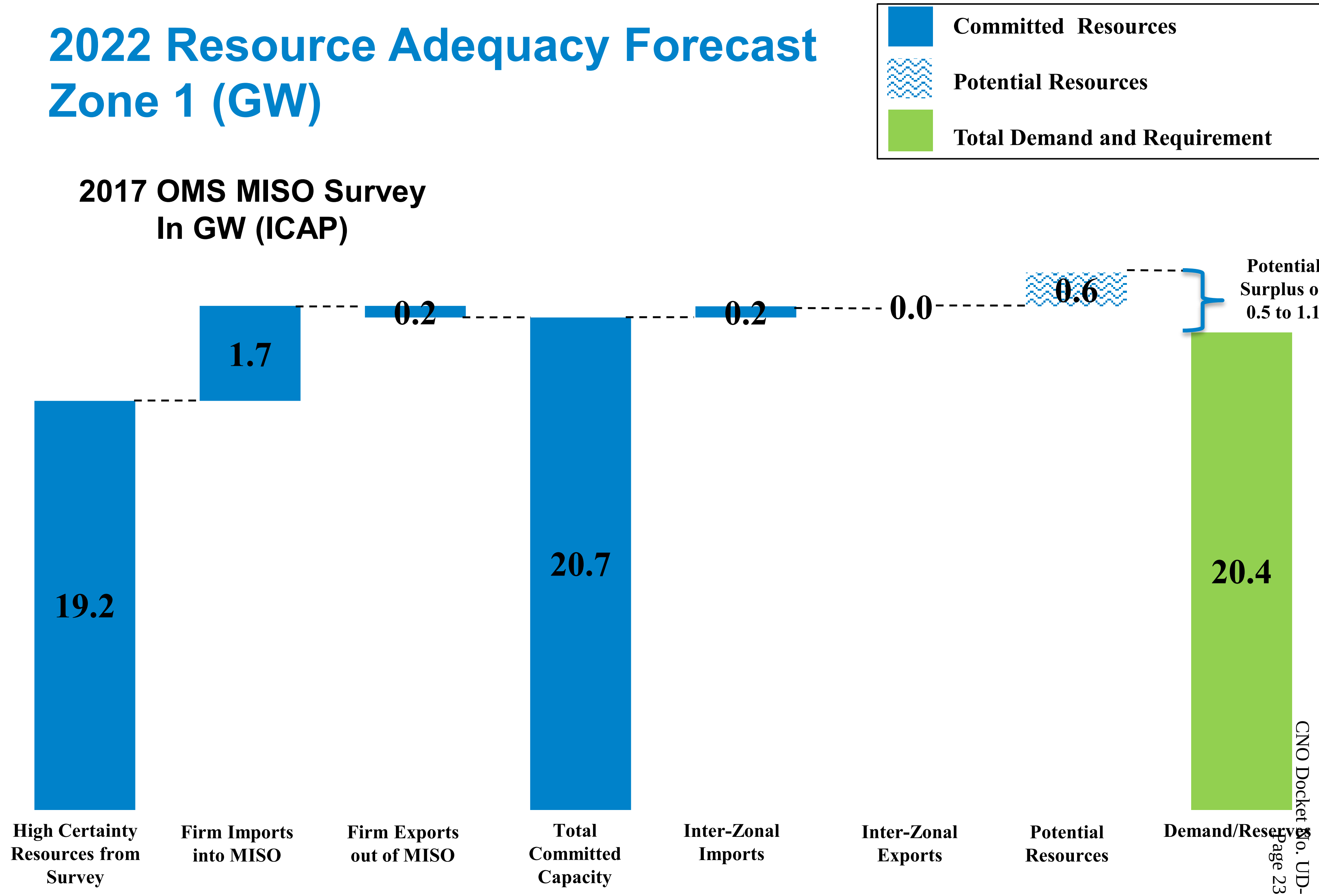
Zone 1 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

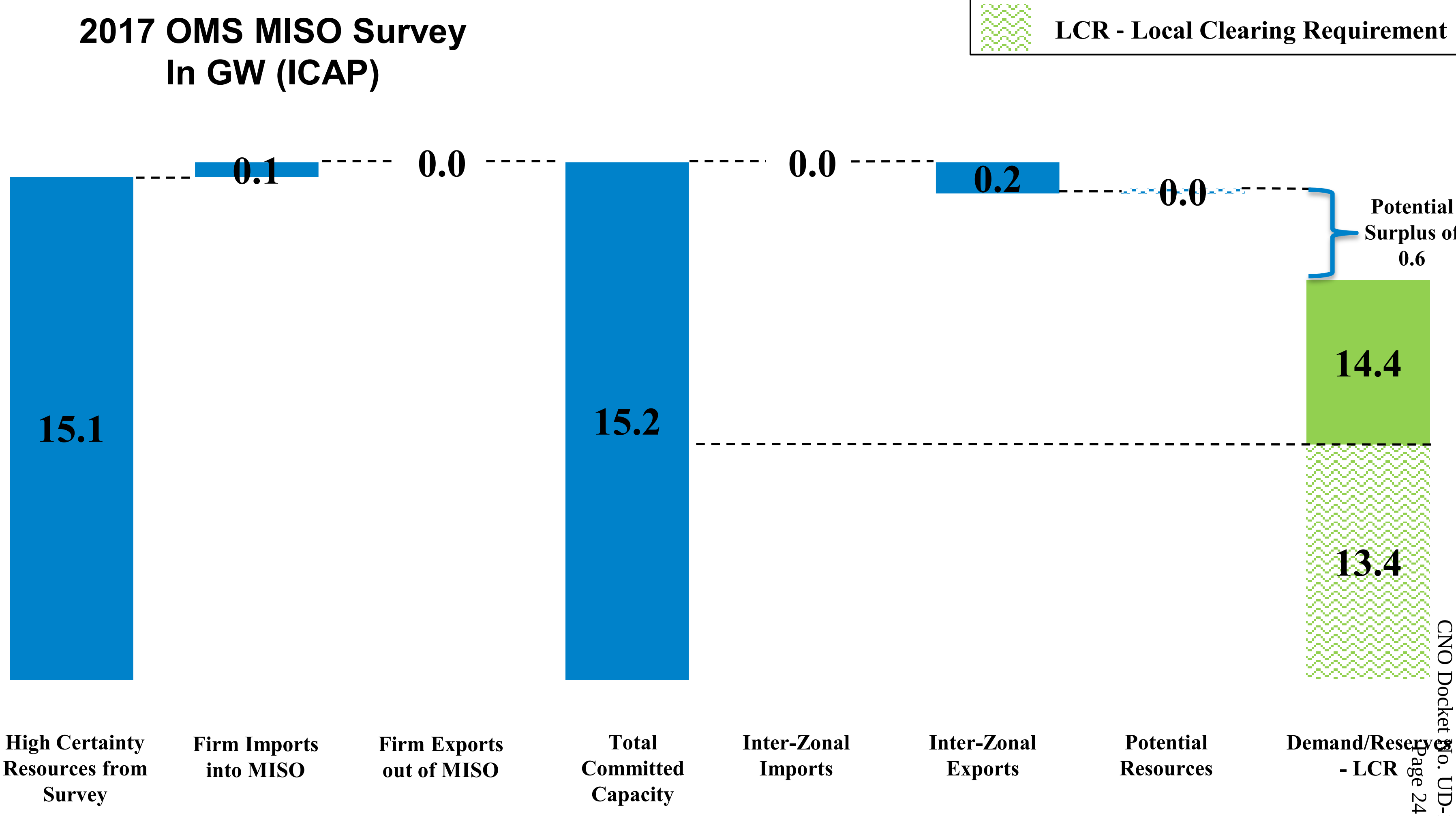
2022 Resource Adequacy Forecast Zone 1 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 2 (GW)



<u>Potential Resources</u> includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 2 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 2	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	15.1	15.0	15.0	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**15.2**	**15.1**	**15.1**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.3	0.3	0.4	F
Demand/Reserves	**14.5**	**14.5**	**14.6**	G
Firm Capacity Position	**0.4**	**0.3**	**0.1**	H =(D+E-F)-G
Low Certainty Resources	0.1	0.3	0.4	I
Potential Capacity Surplus/Deficit	**0.5**	**0.6**	**0.5**	J =(H+I)

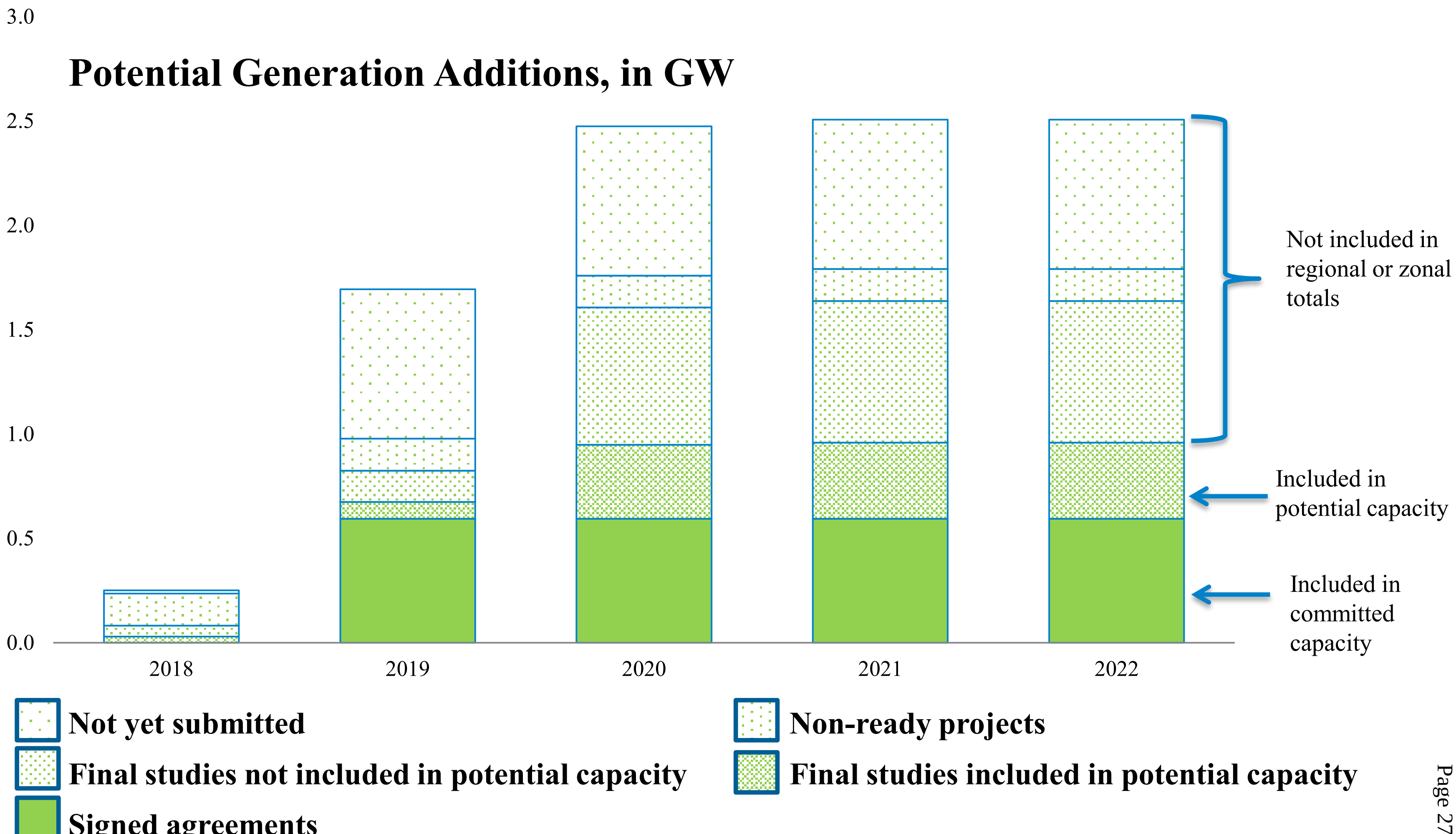
2016 vs 2017 OMS MISO Survey Results
Zone 2

Zone 2 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)

New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

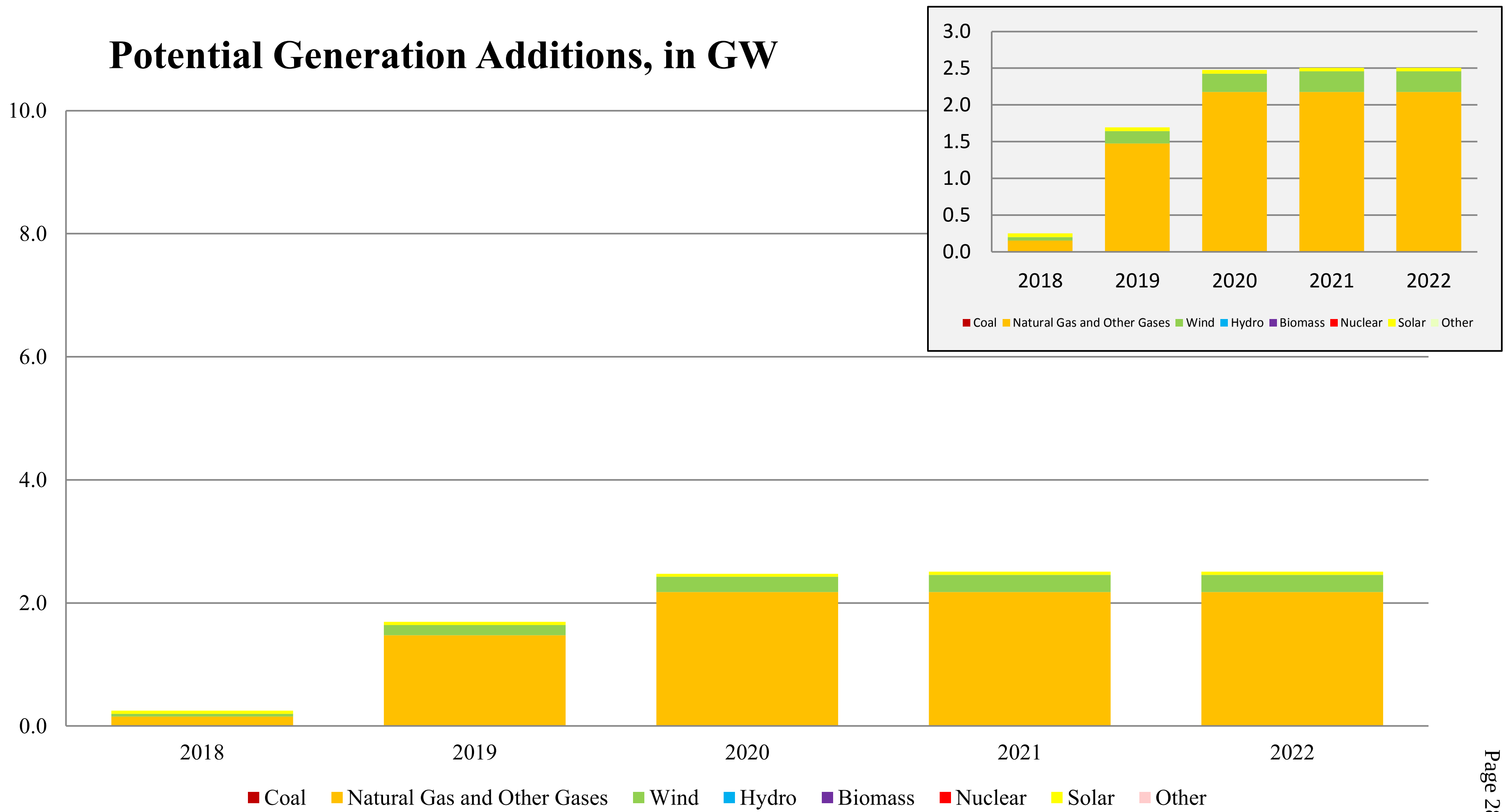
Zone 2 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

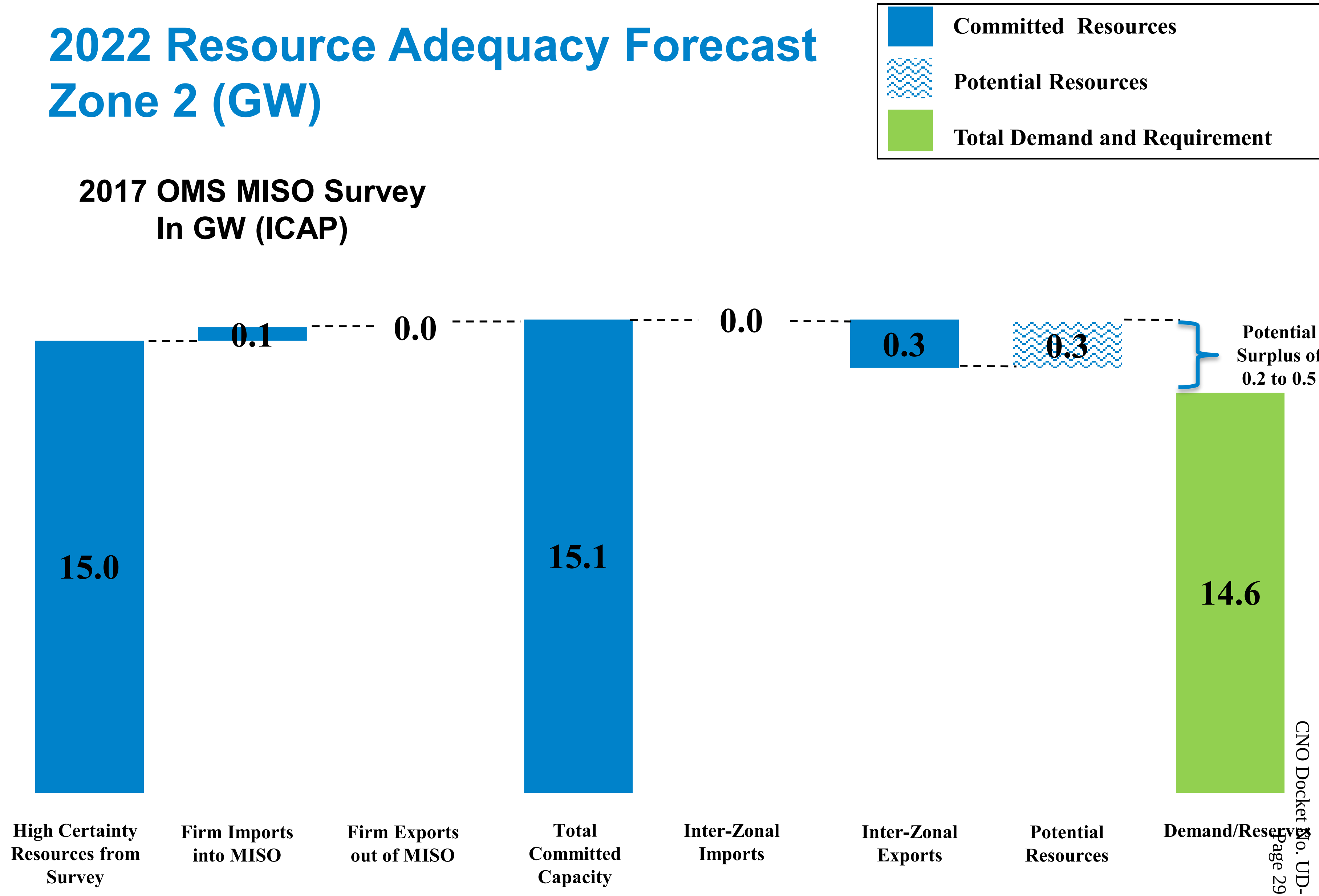
<u>Non-ready projects</u> will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 2 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

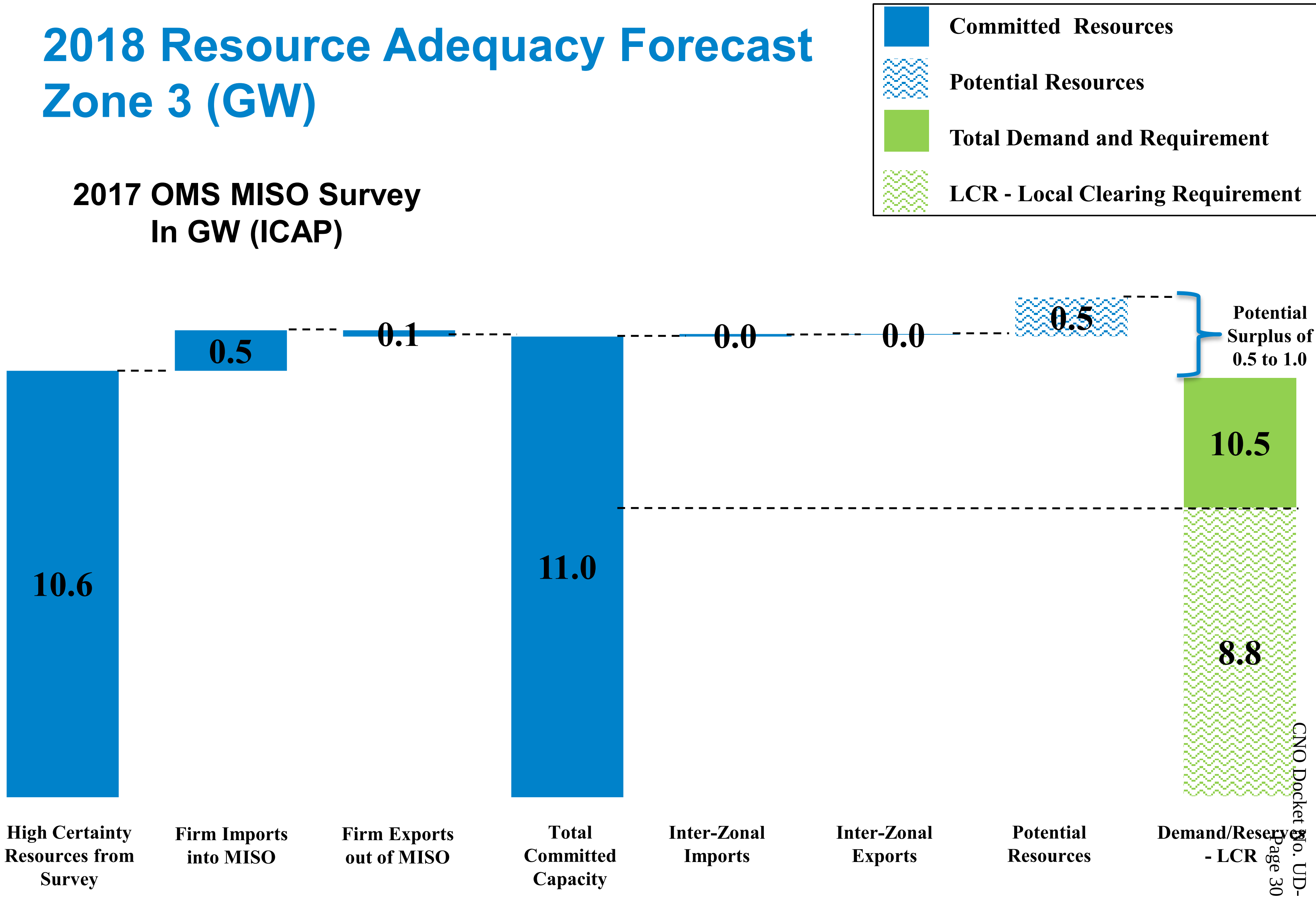
2022 Resource Adequacy Forecast Zone 2 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey
In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey

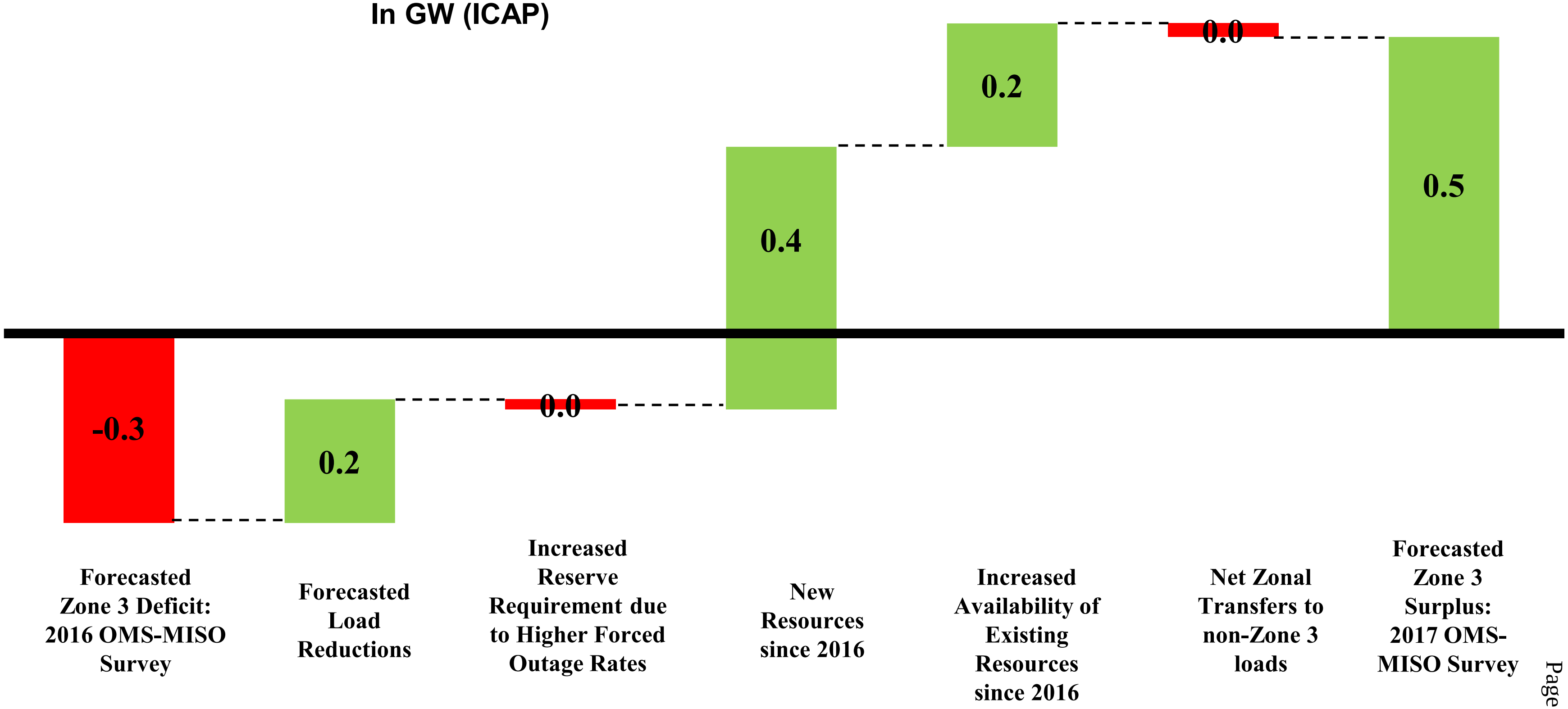
Values In GW (ICAP)

Zone 3	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	10.6	10.6	10.7	A
Firm Imports into MISO	0.5	0.5	0.5	B
Firm Exports out of MISO	0.1	0.1	0.1	C
Total High Certainty Capacity	**11.0**	**11.0**	**11.1**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**10.6**	**10.7**	**10.8**	G
Firm Capacity Position	**0.4**	**0.3**	**0.3**	H =(D+E-F)-G
Low Certainty Resources	0.6	0.7	0.7	I
Potential Capacity Surplus/Deficit	**1.0**	**1.0**	**1.0**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 3

Zone 3 2018 Outlook Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)

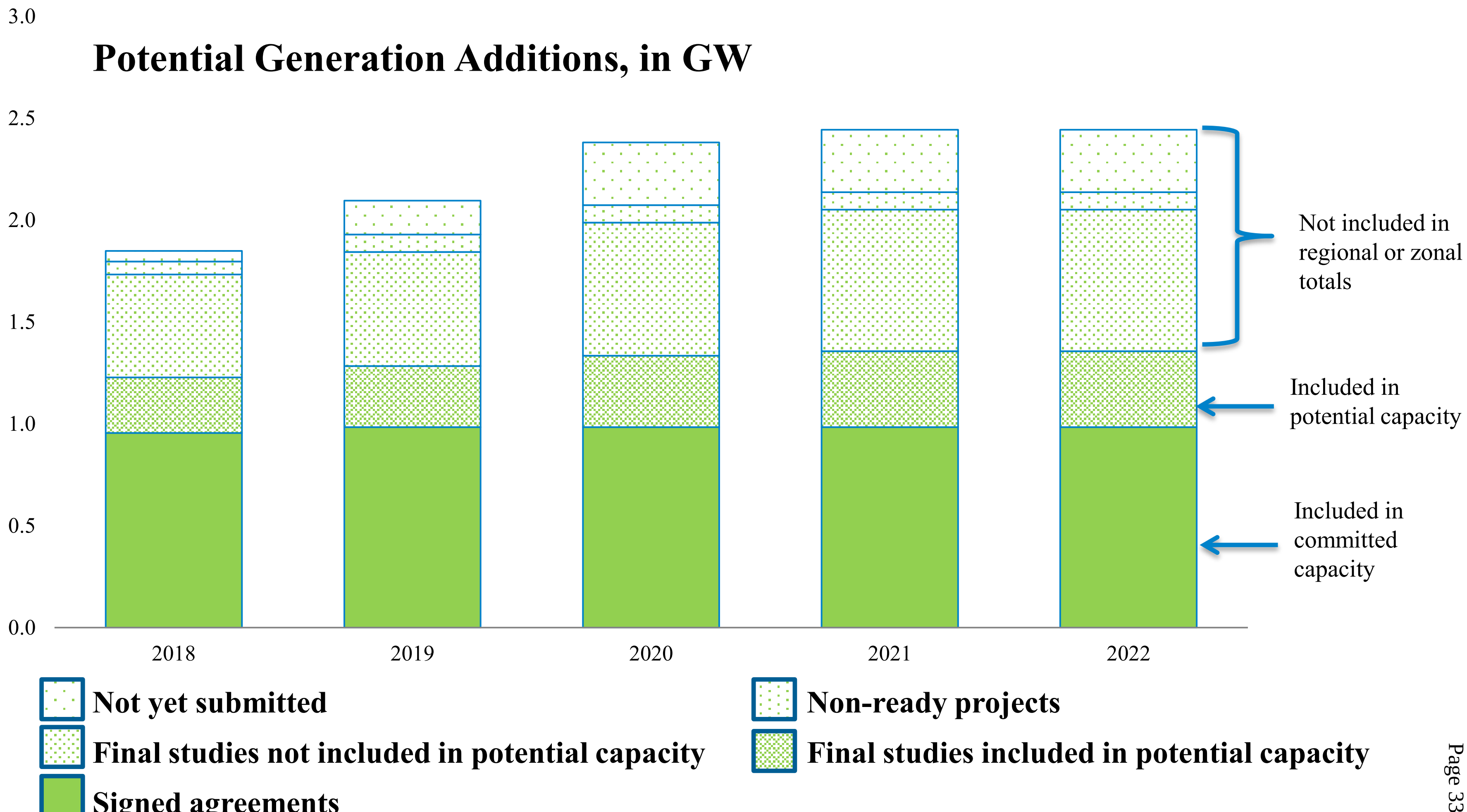


<u>New resources</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources

<u>Increased availability</u> results from deferred retirements and internal resources with reduced commitments to non-MISO load

Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

Zone 3 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit
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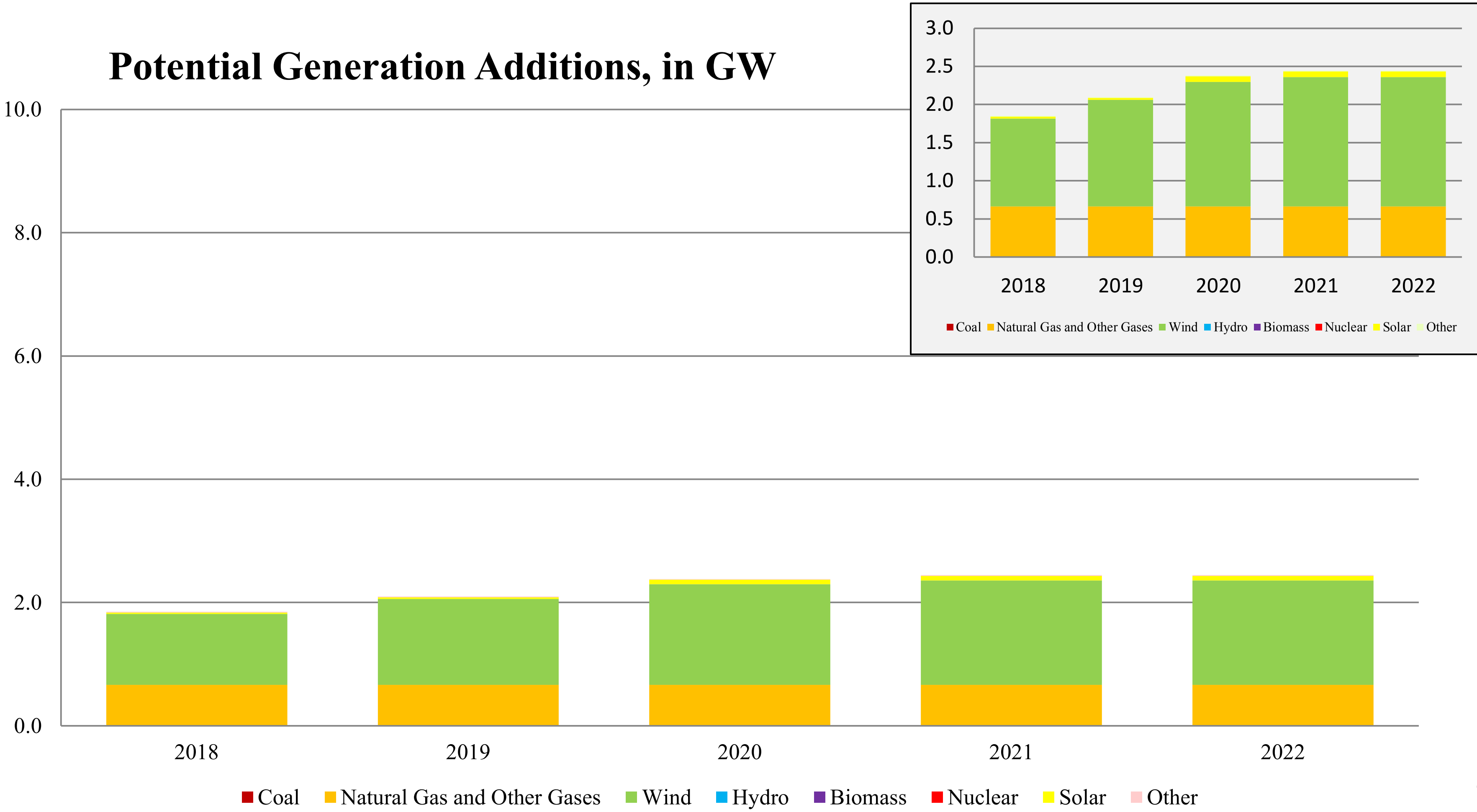
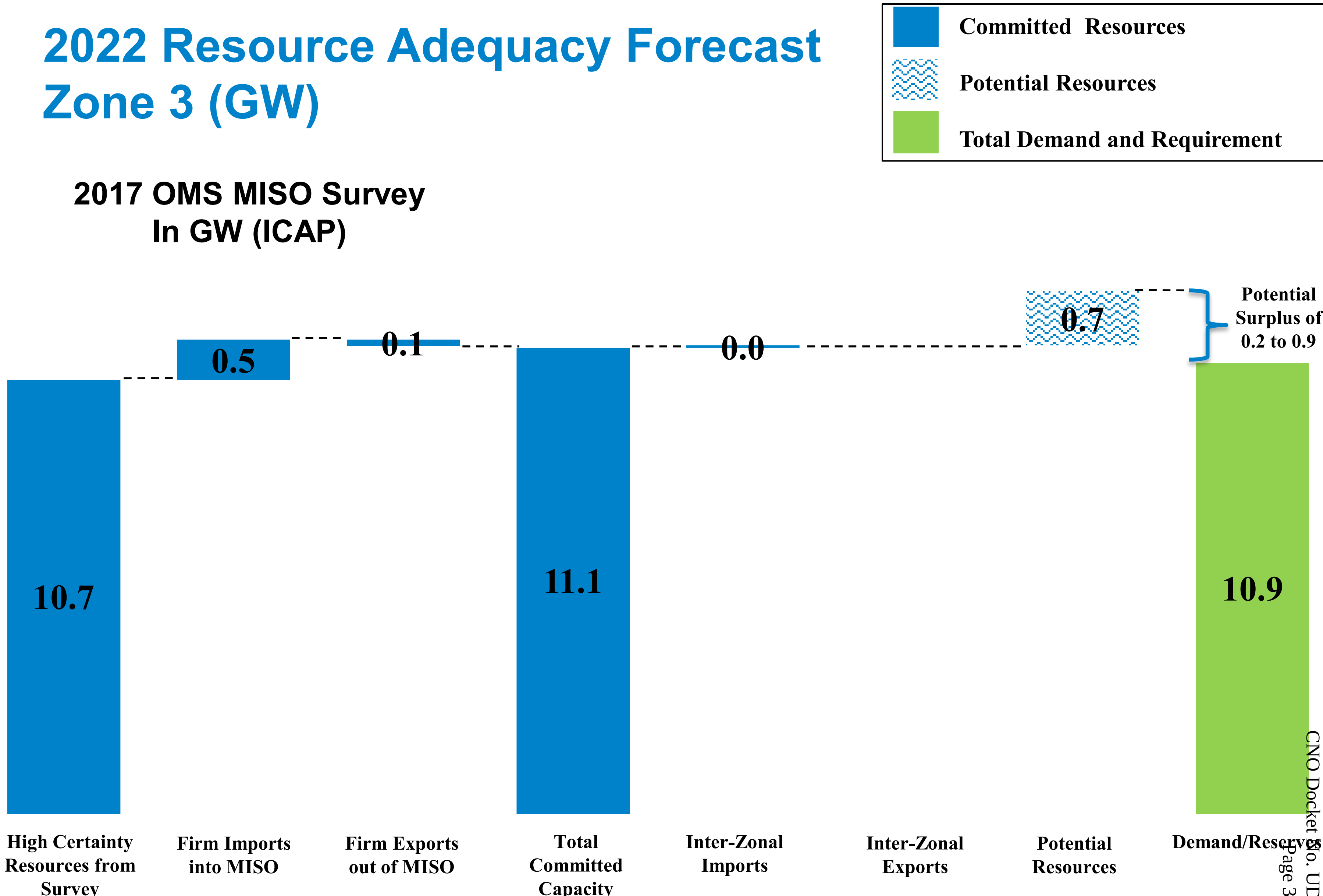
Zone 3 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

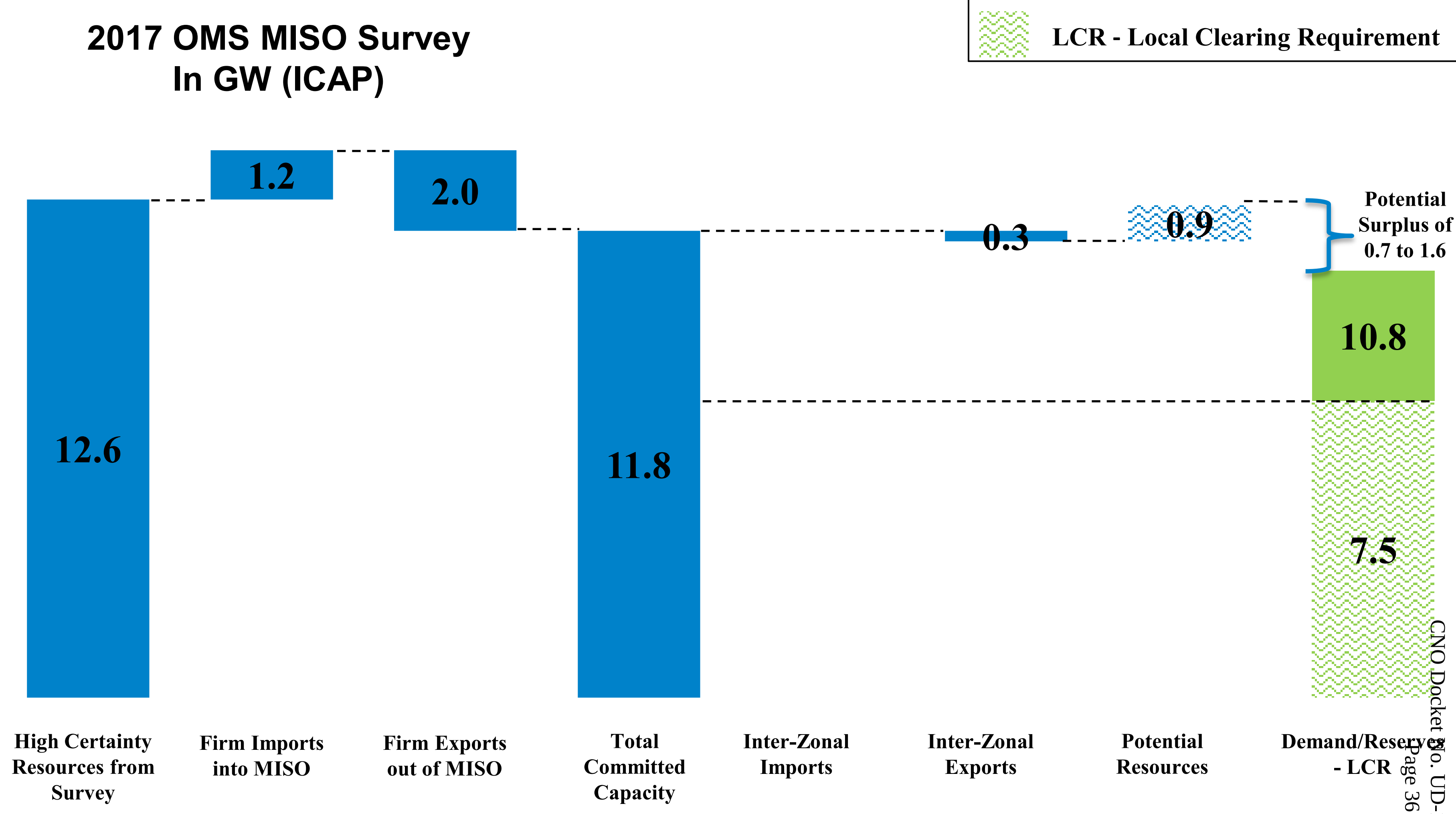
2022 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 4 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 4 (GW)

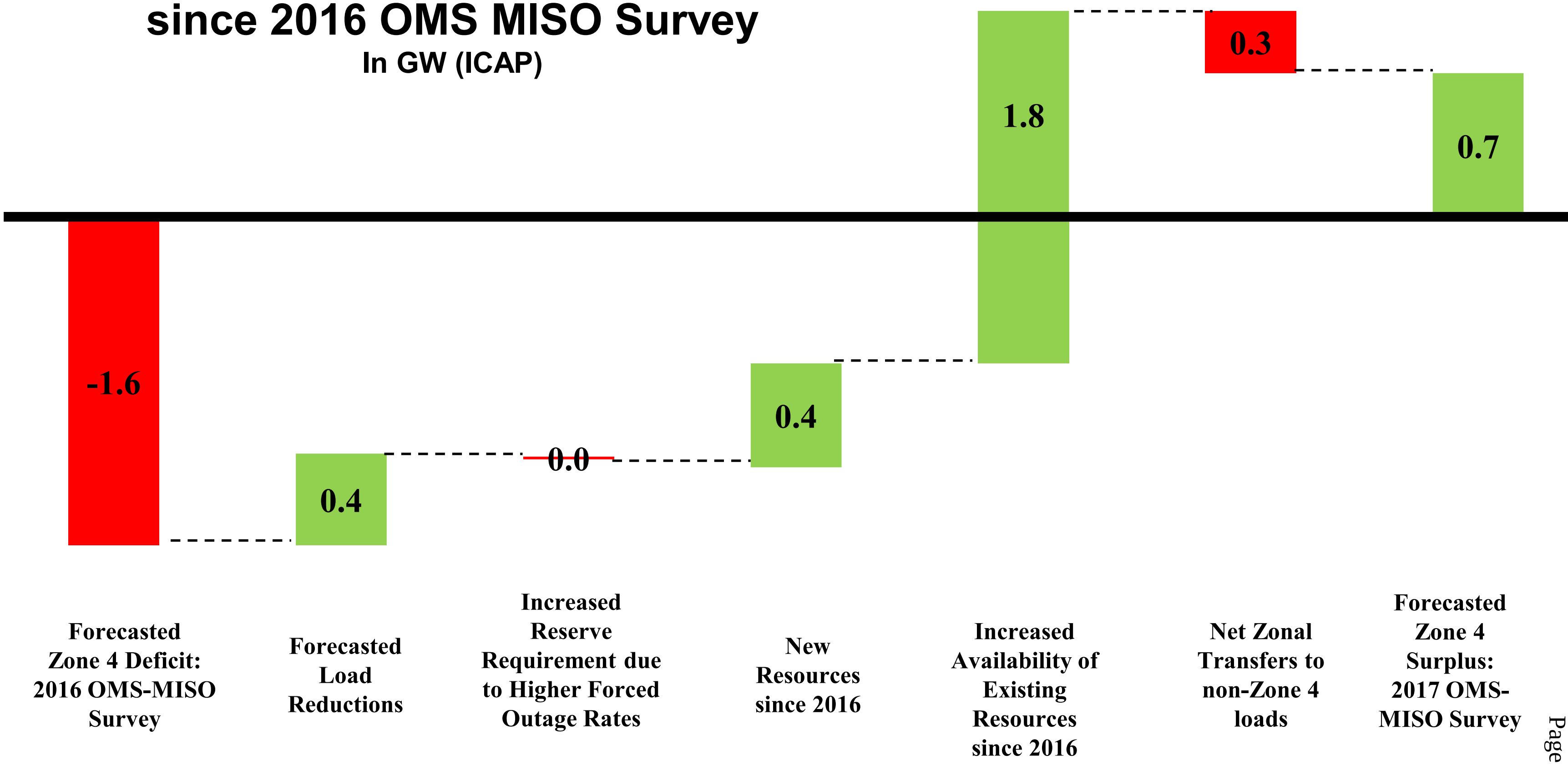
2017 OMS MISO Survey

Values In GW (ICAP)

Zone 4	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	12.6	12.6	12.5	A
Firm Imports into MISO	1.2	1.2	1.2	B
Firm Exports out of MISO	1.8	1.5	1.5	C
Total High Certainty Capacity	**12.0**	**12.3**	**12.2**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.2	0.2	0.4	F
Demand/Reserves	**10.9**	**10.8**	**10.8**	G
Firm Capacity Position	**0.9**	**1.3**	**1.0**	H =(D+E-F)-G
Low Certainty Resources	0.9	1.0	1.1	I
Potential Capacity Surplus/Deficit	**1.8**	**2.3**	**2.1**	J =(H+I)

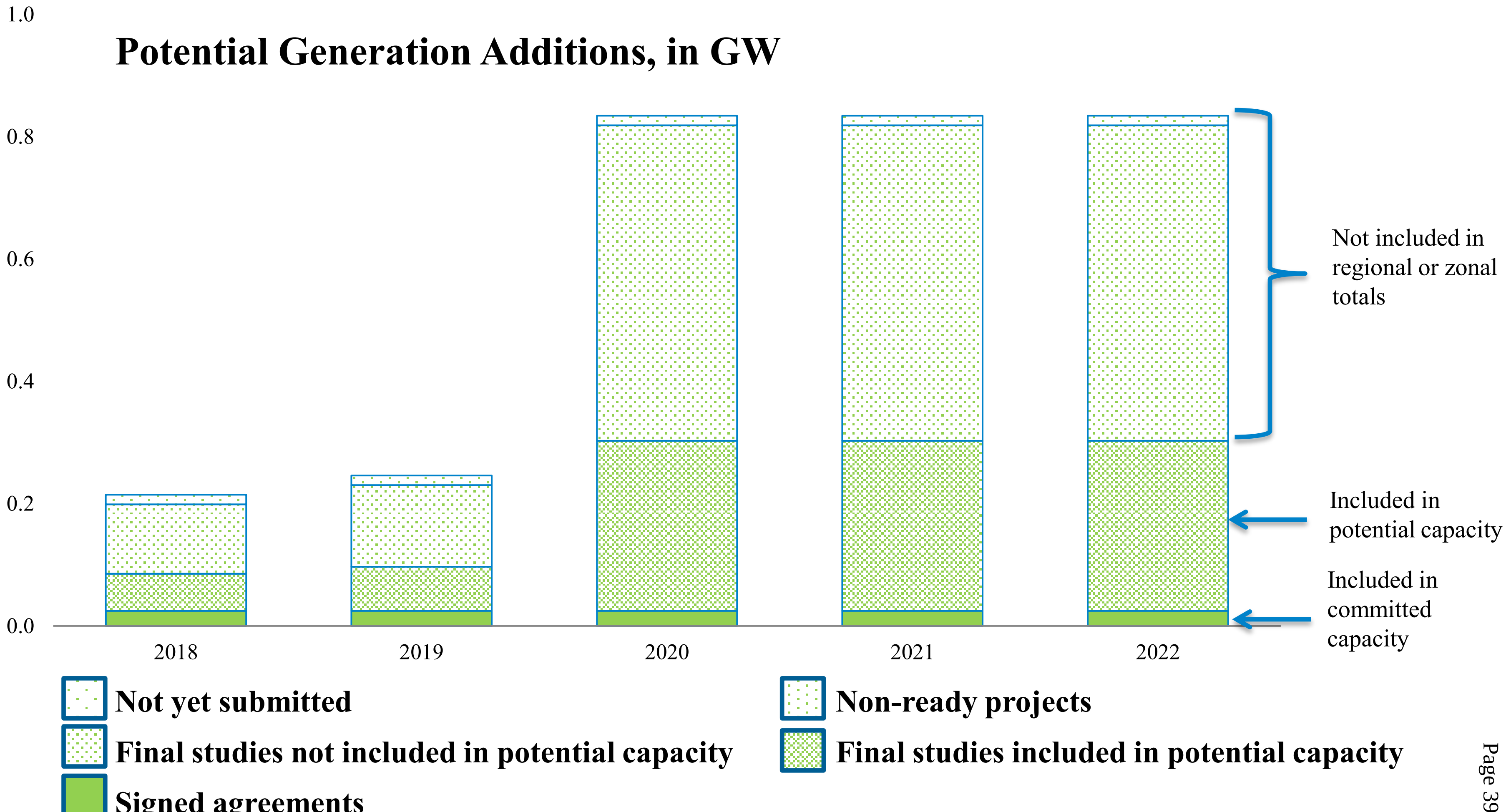
Activity in Illinois resulted in much of the year-over-year regional change; continued action is required to achieve forecasted balances

Zone 4 (Illinois) 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

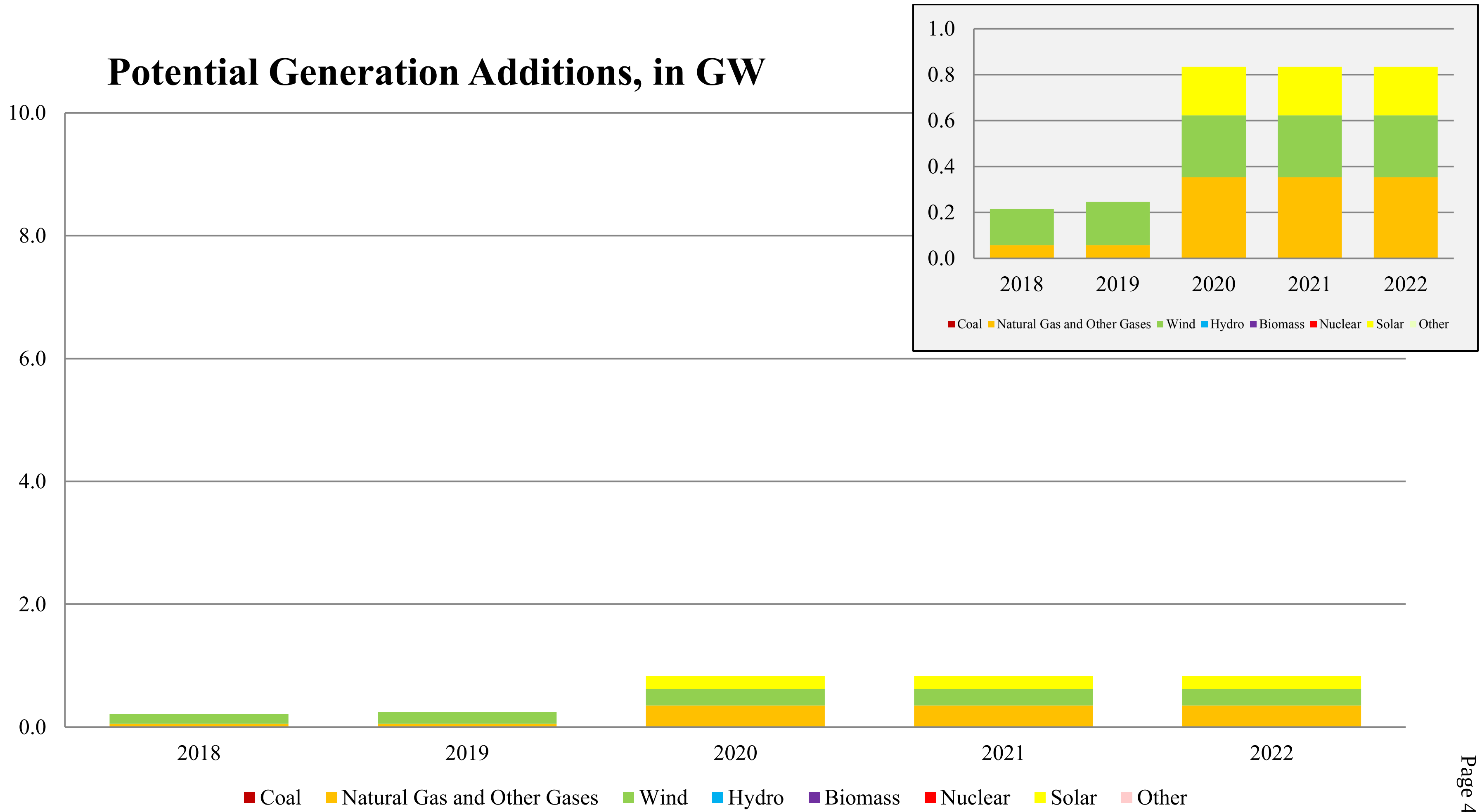
Zone 4 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

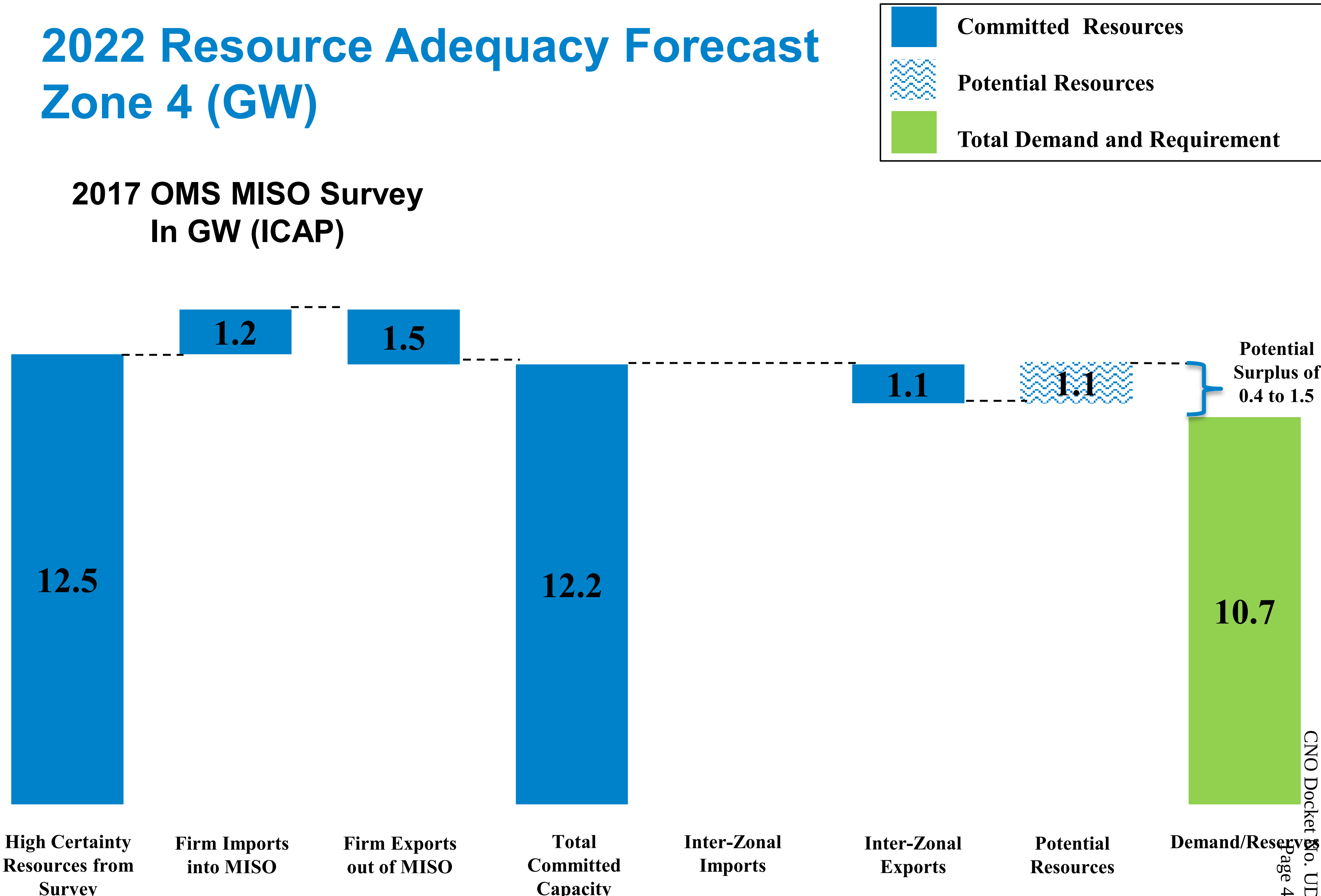
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 4 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

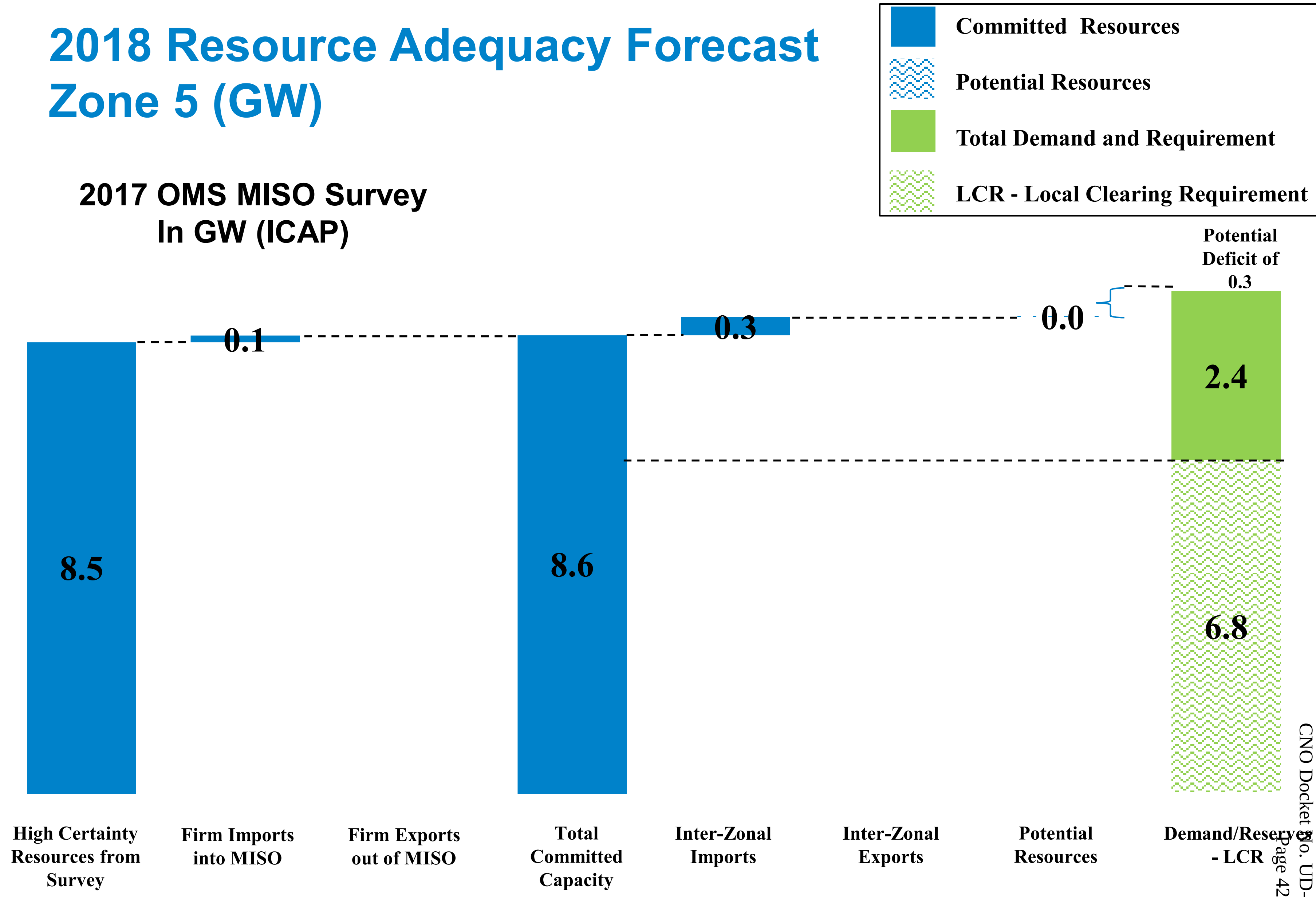
2022 Resource Adequacy Forecast Zone 4 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 5 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

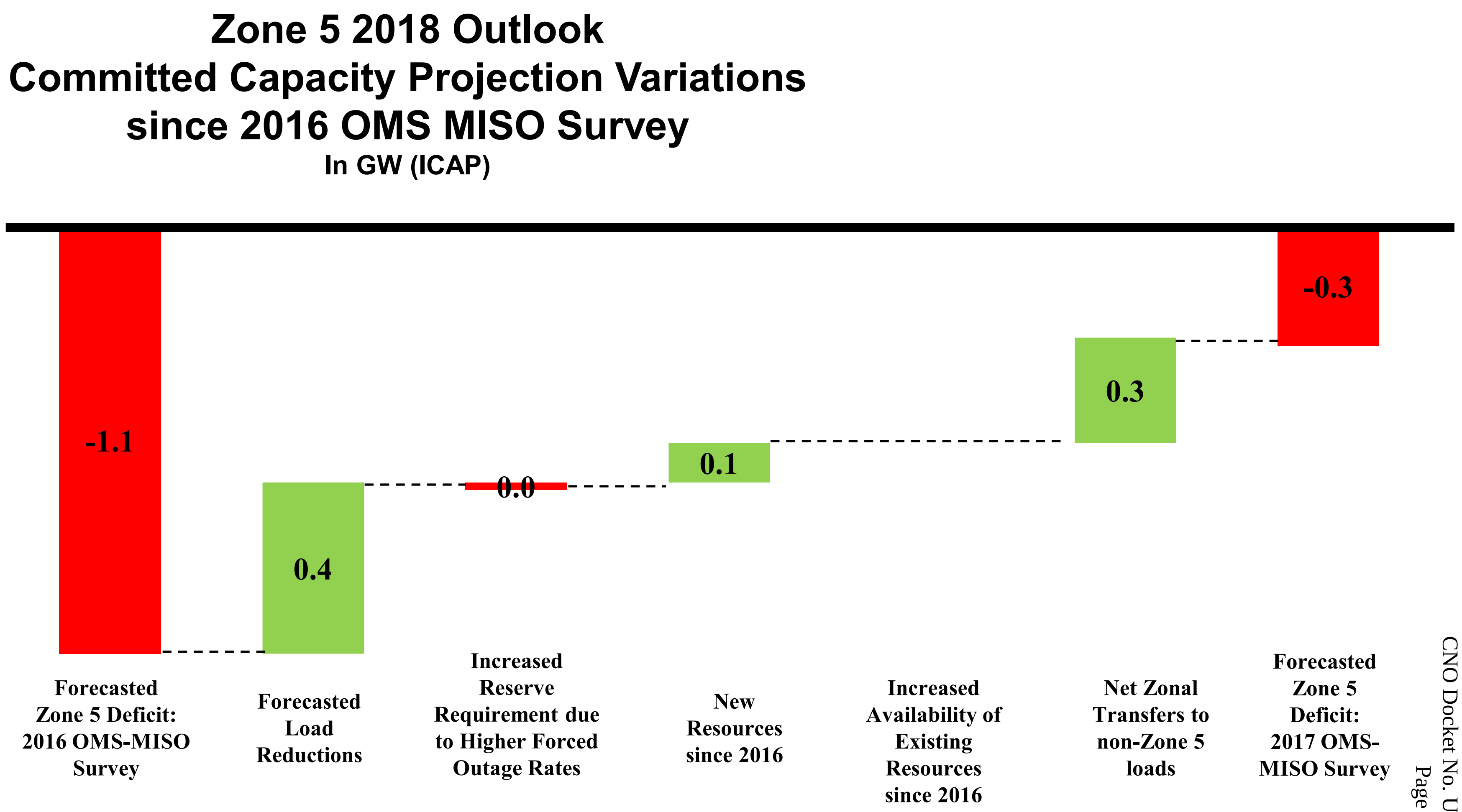
2019 - 2021 Resource Adequacy Forecast Zone 5 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 5	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	8.6	8.6	8.4	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**8.7**	**8.7**	**8.5**	D = (A+B)-C
Inter-Zonal Imports	0.2	0.2	0.4	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**9.2**	**9.2**	**9.2**	G
Firm Capacity Position	**-0.3**	**-0.3**	**-0.3**	H =(D+E-F)-G
Low Certainty Resources	0.0	0.0	0.1	I
Potential Capacity Surplus/Deficit	**-0.3**	**-0.3**	**-0.2**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results
Zone 5



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
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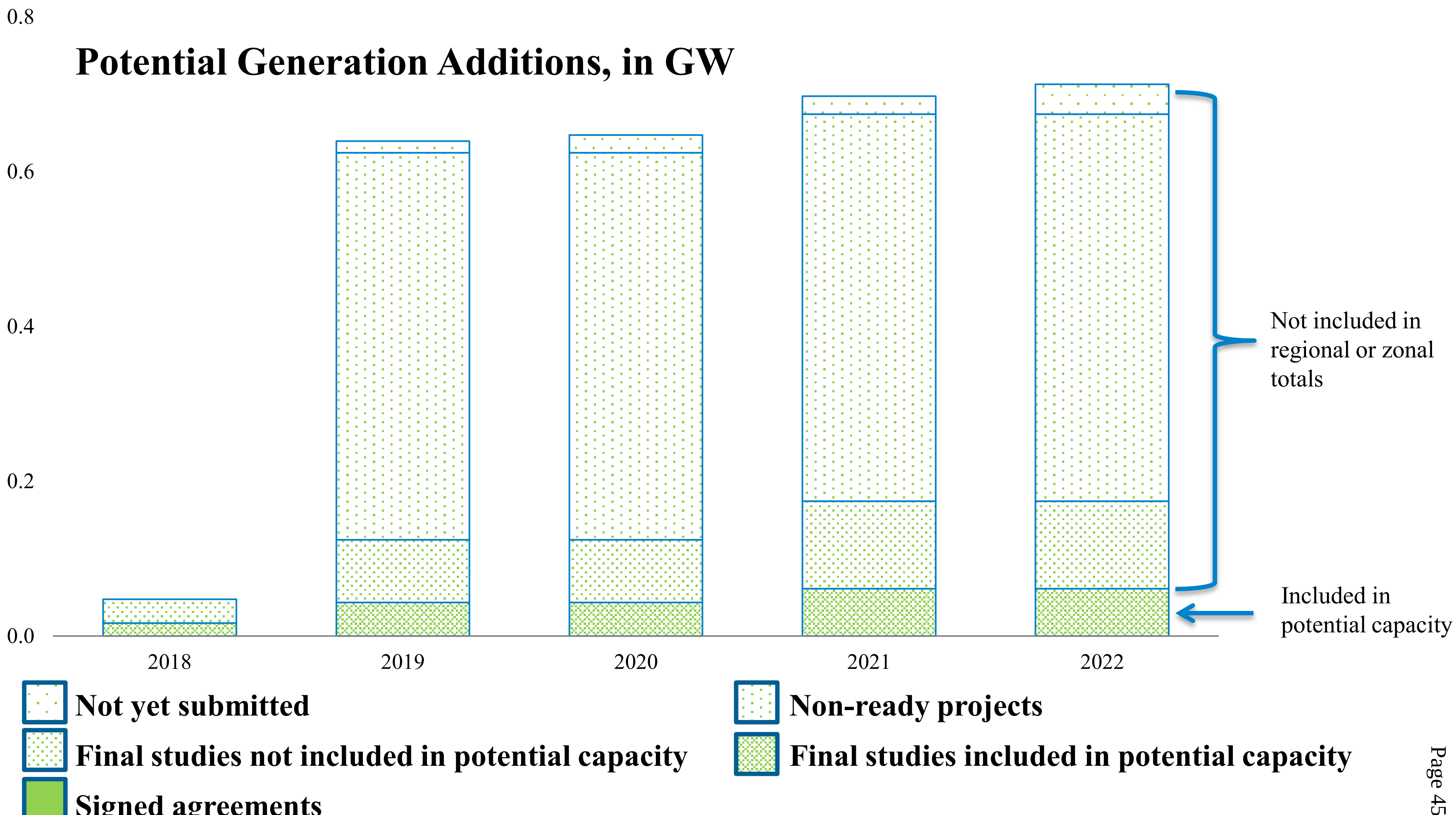
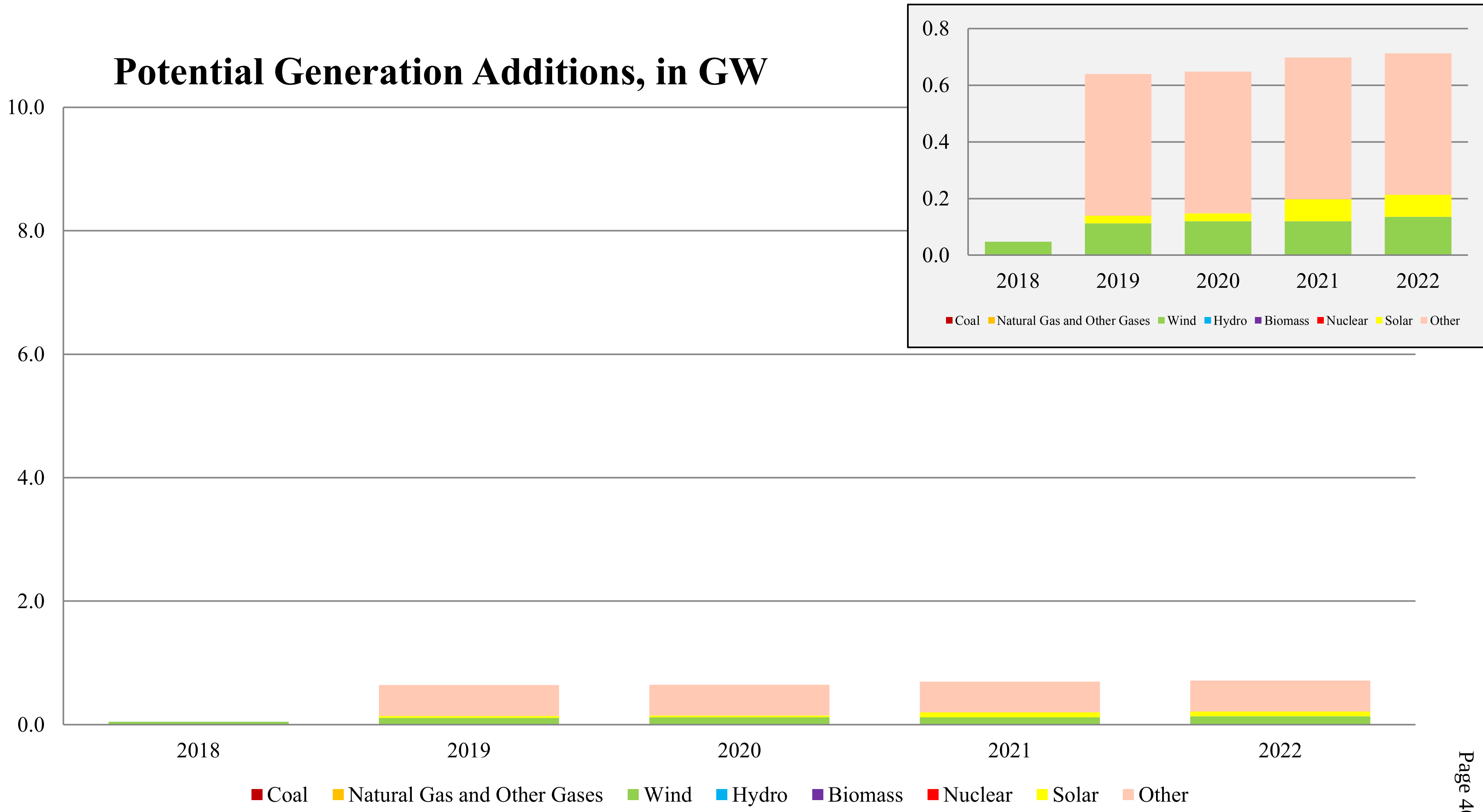
Zone 5 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

<u>Non-ready projects</u> will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 5 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
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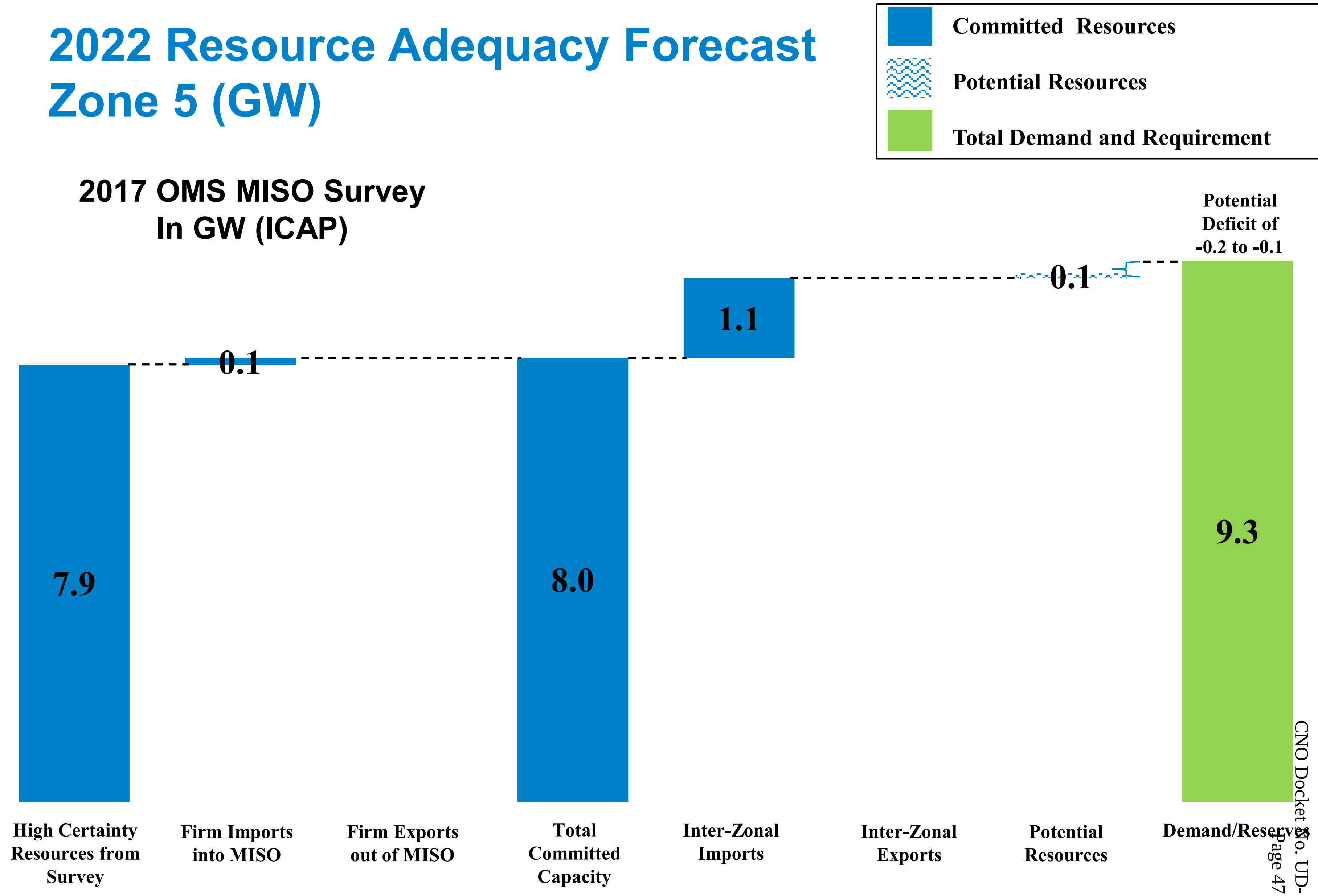
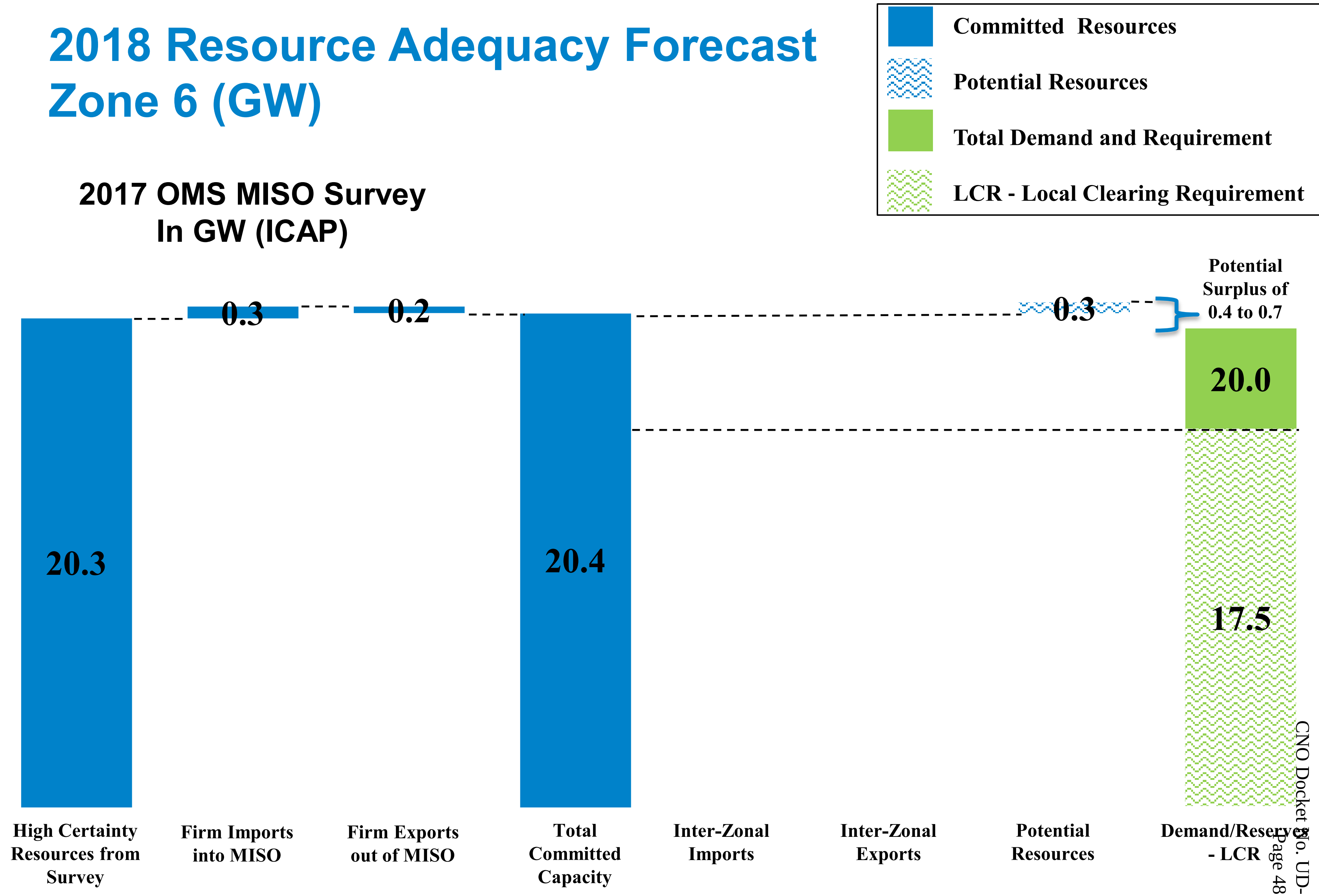
2022 Resource Adequacy Forecast Zone 5 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 6 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

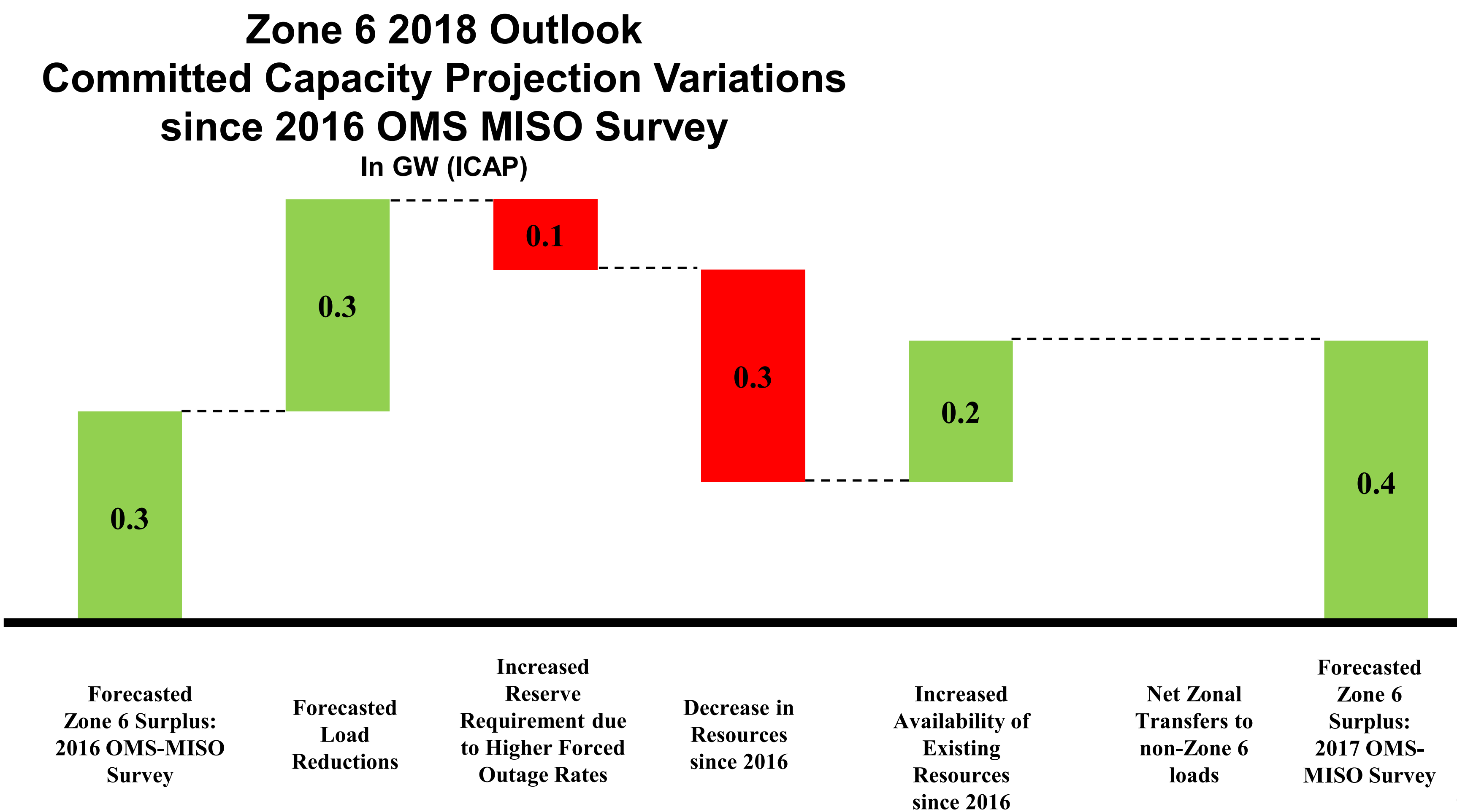
2019 - 2021 Resource Adequacy Forecast Zone 6 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 6	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	20.3	20.0	20.0	A
Firm Imports into MISO	0.4	0.4	0.4	B
Firm Exports out of MISO	0.2	0.2	0.2	C
Total High Certainty Capacity	**20.5**	**20.2**	**20.2**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**20.0**	**20.2**	**20.3**	G
Firm Capacity Position	**0.5**	**0.0**	**-0.1**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.6	0.7	I
Potential Capacity Surplus/Deficit	**0.8**	**0.6**	**0.6**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 6



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
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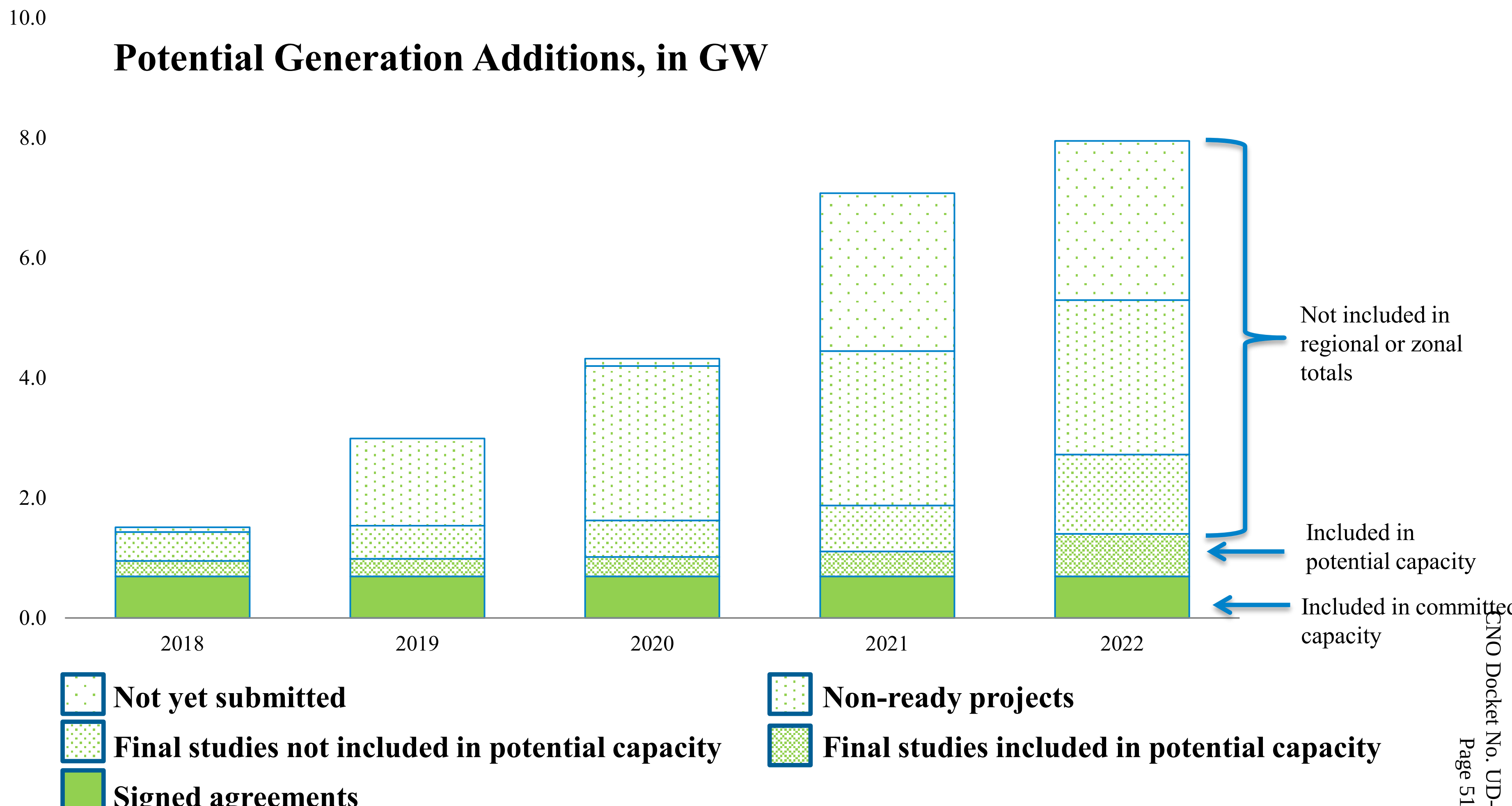
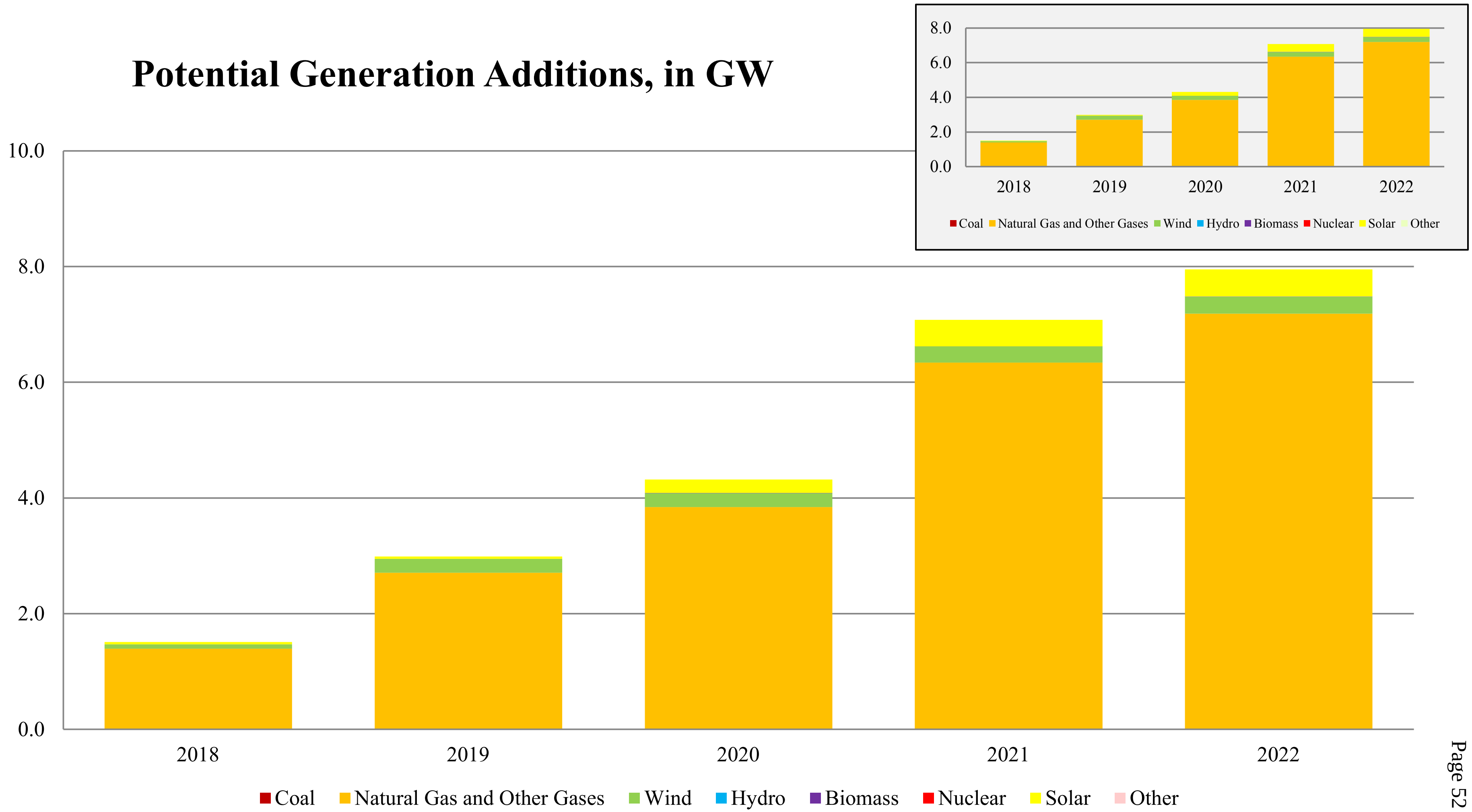
Zone 6 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 6 New Resources Additions by Fuel Type



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Wind and solar resources are represented at their expected capacity credit
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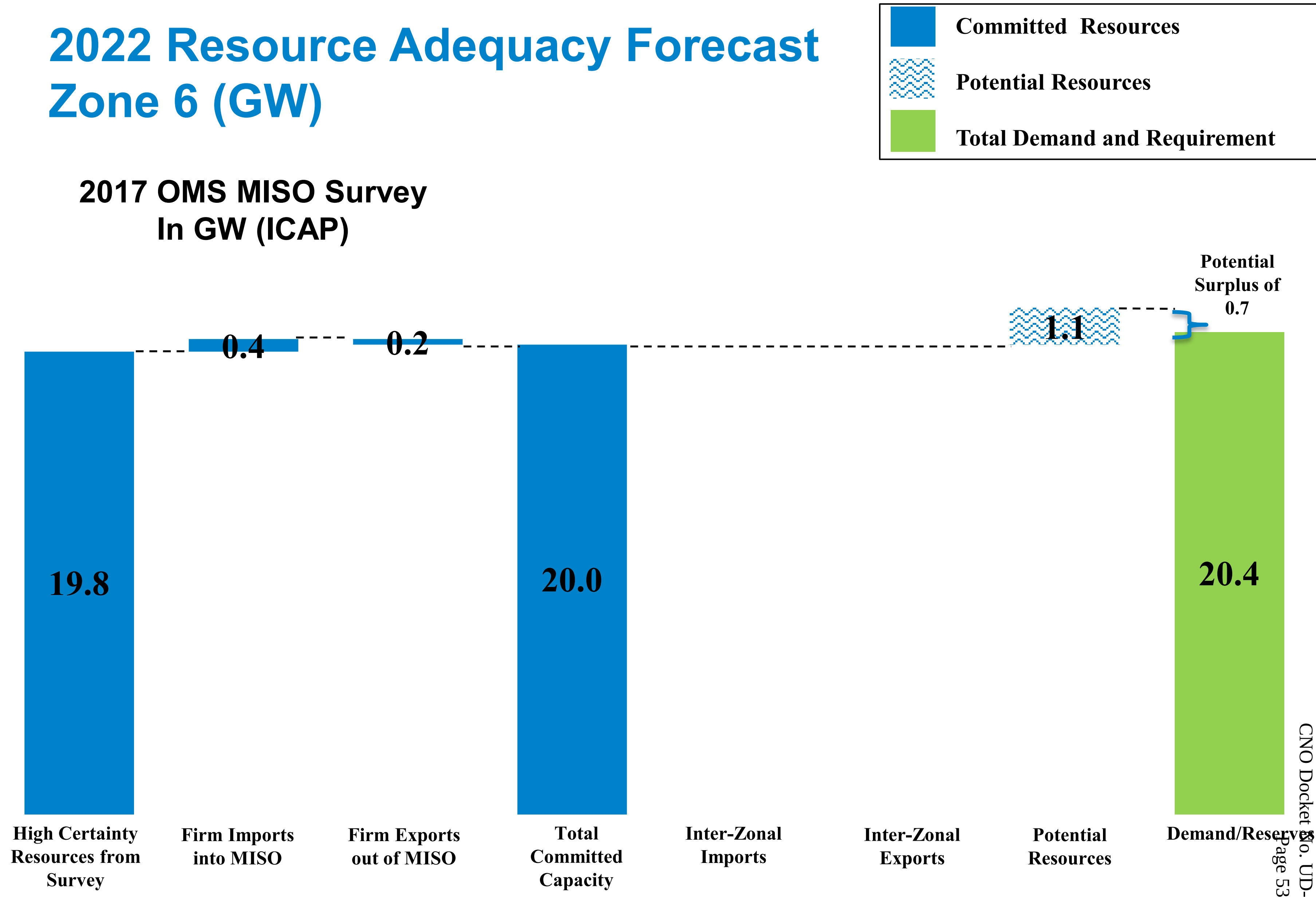
2022 Resource Adequacy Forecast Zone 6 (GW)

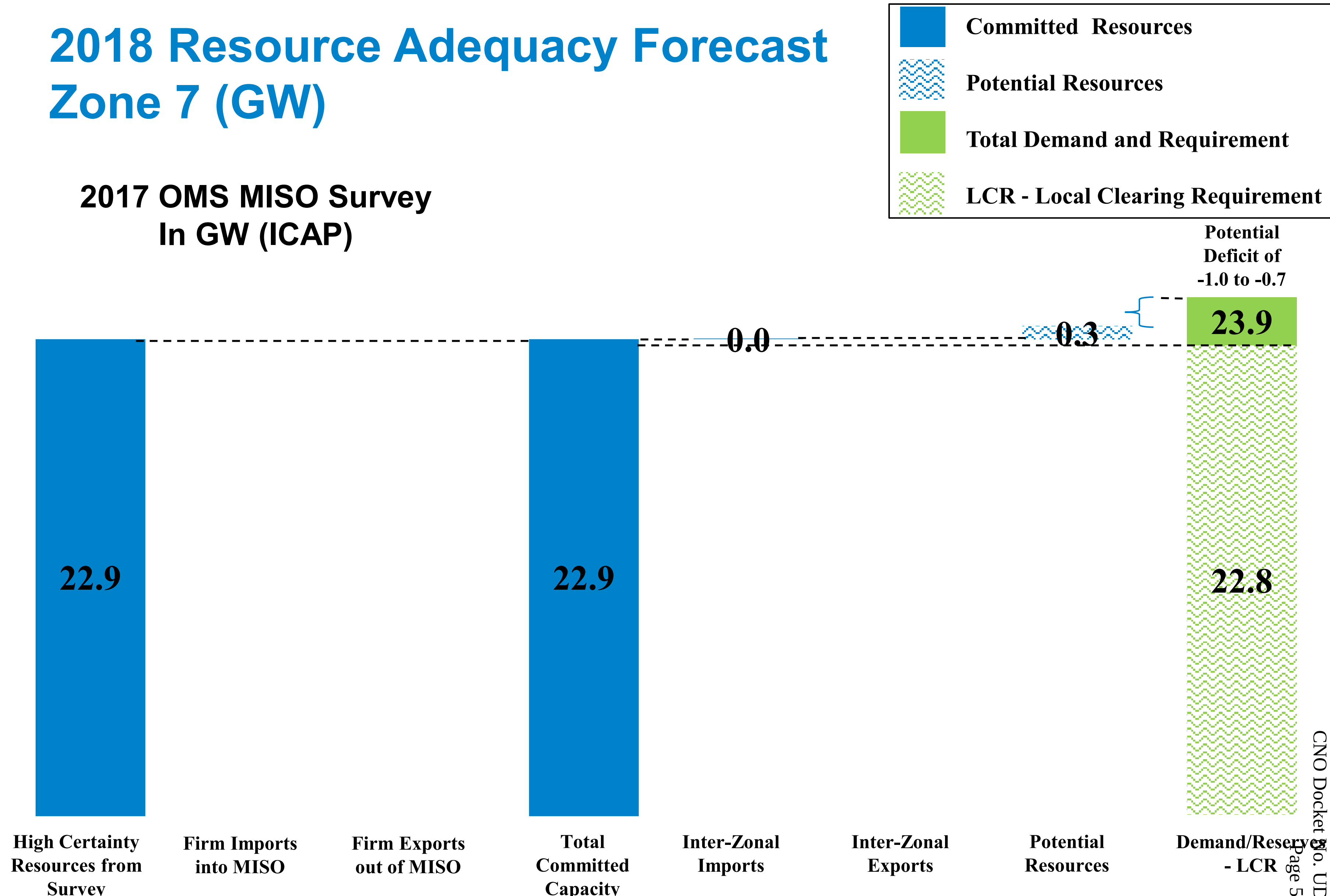
2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 7 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

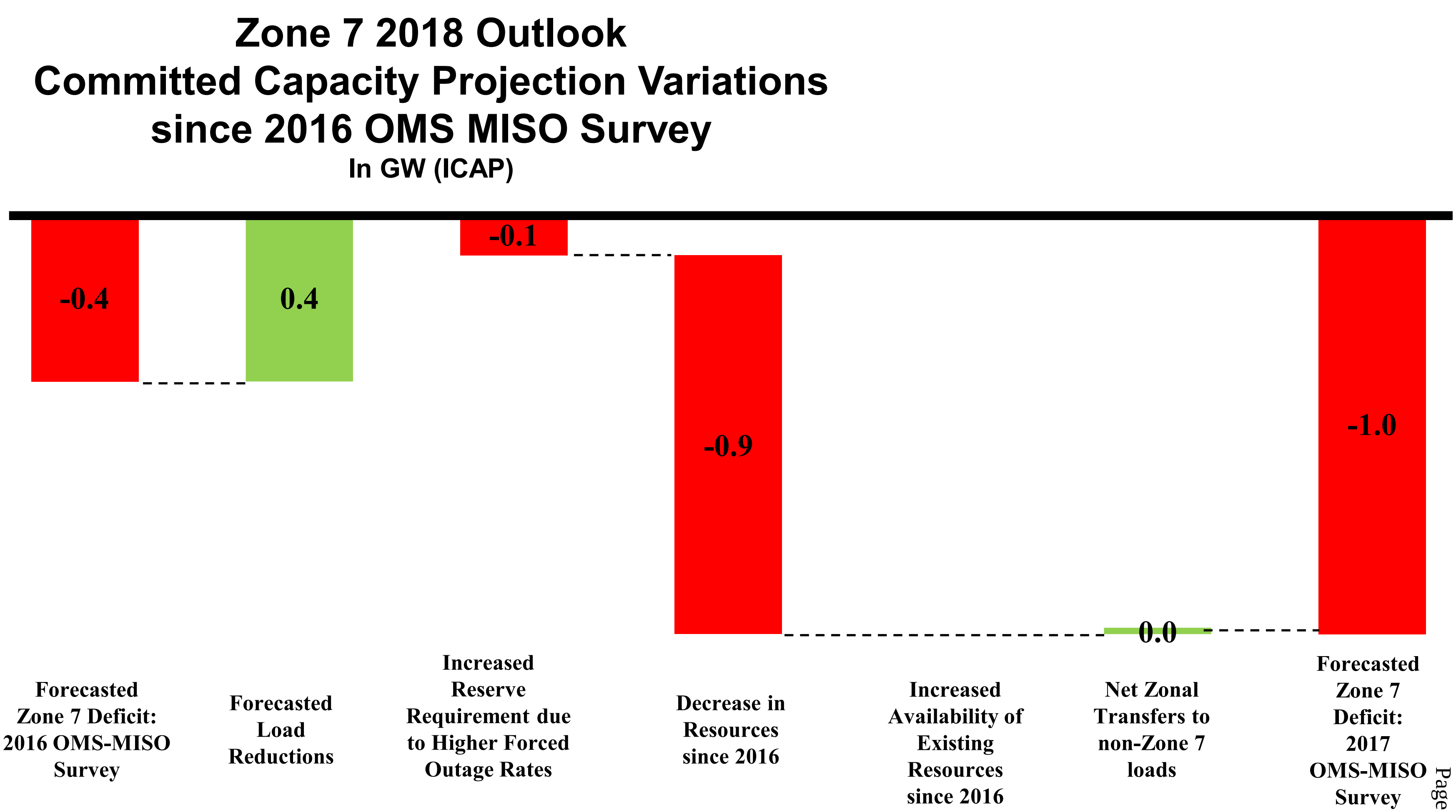
2019 - 2021 Resource Adequacy Forecast Zone 7 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 7	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	23.4	23.2	23.3	A
Firm Imports into MISO	0.0	0.0	0.0	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**23.4**	**23.2**	**23.3**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**23.8**	**23.7**	**23.7**	G
Firm Capacity Position	**-0.4**	**-0.5**	**-0.4**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.4	0.4	I
Potential Capacity Surplus/Deficit	**-0.1**	**-0.1**	**0.0**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 7



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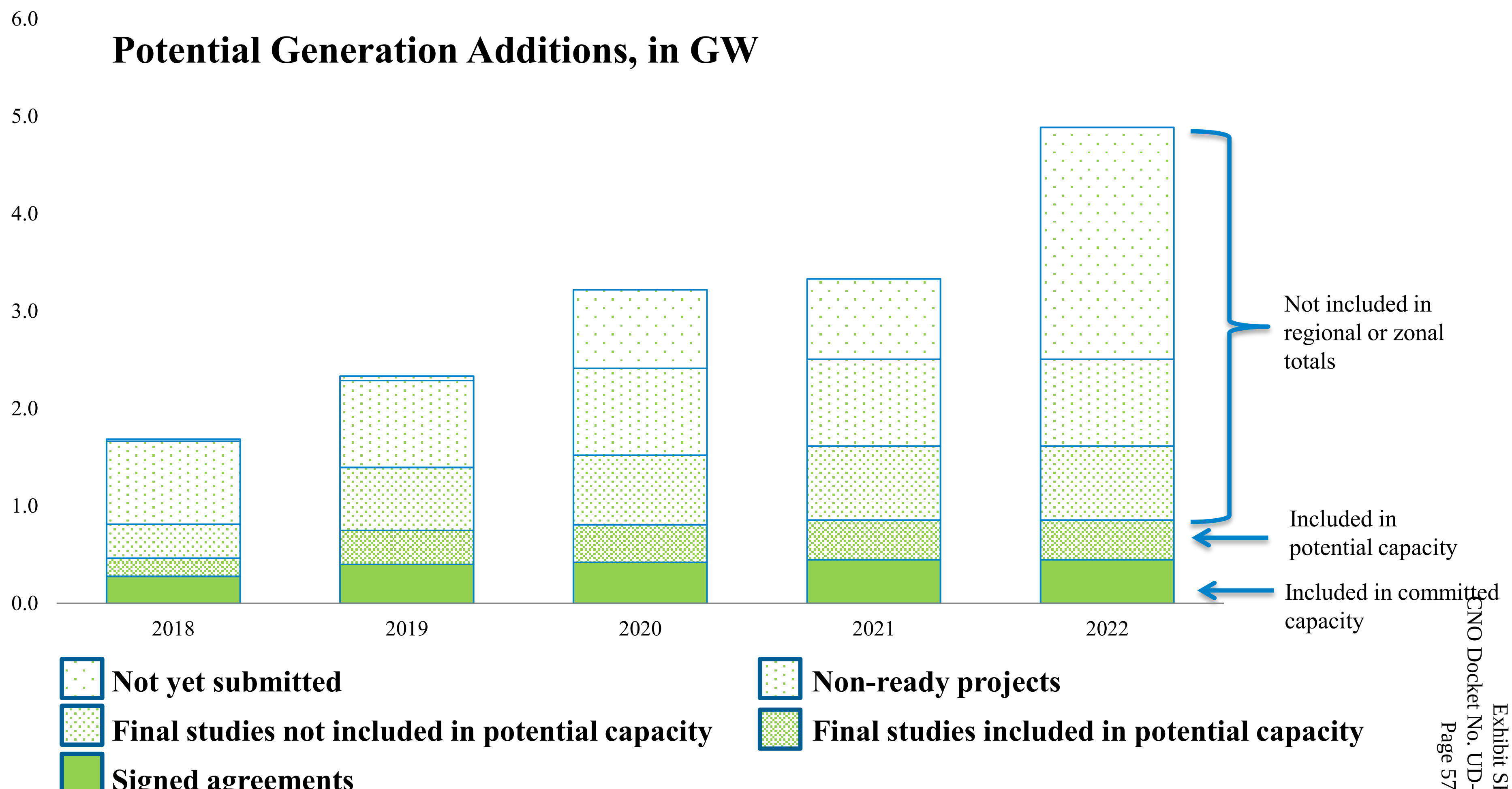
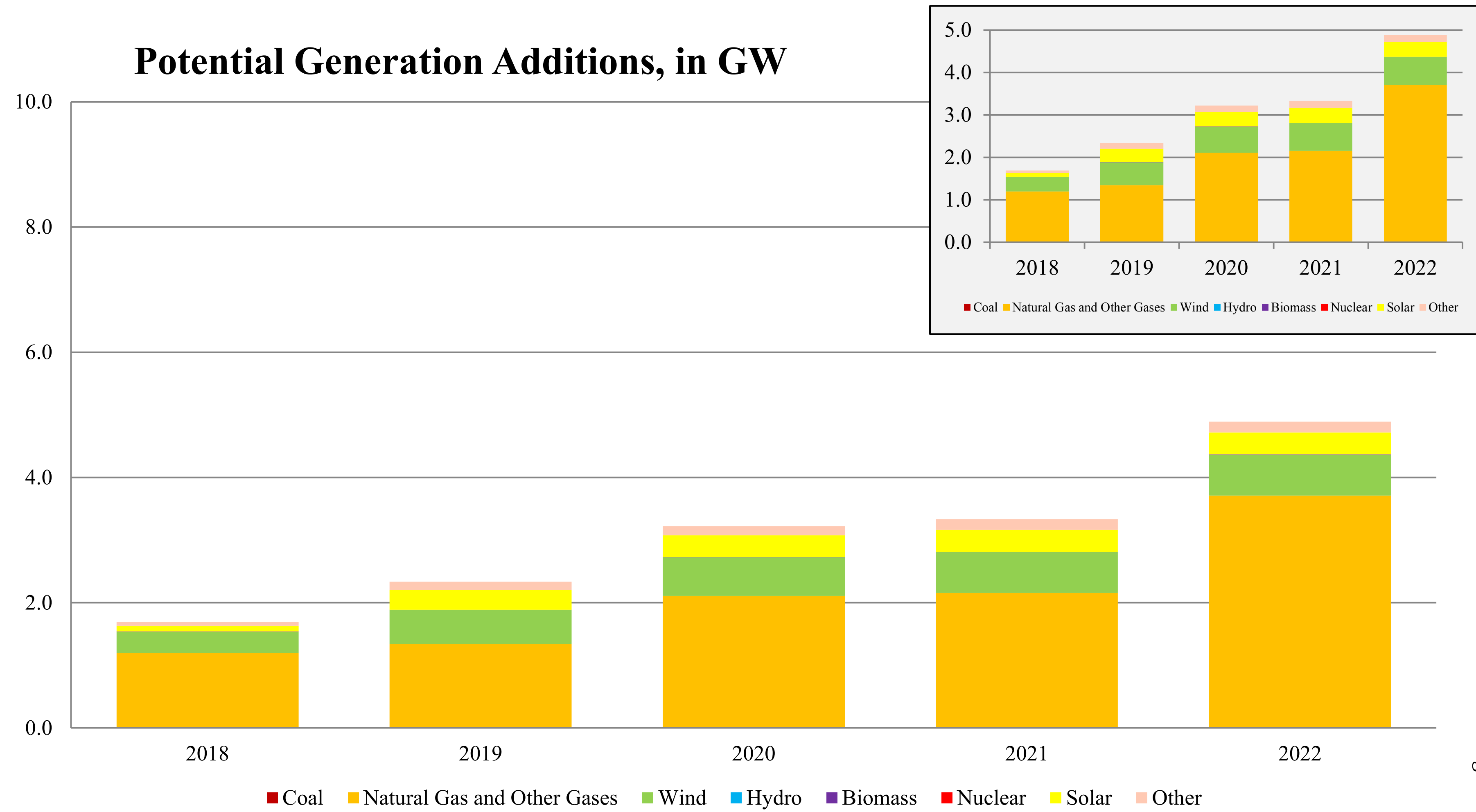
Zone 7 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 7 New Resources Additions by Fuel Type



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Wind and solar resources are represented at their expected capacity credit
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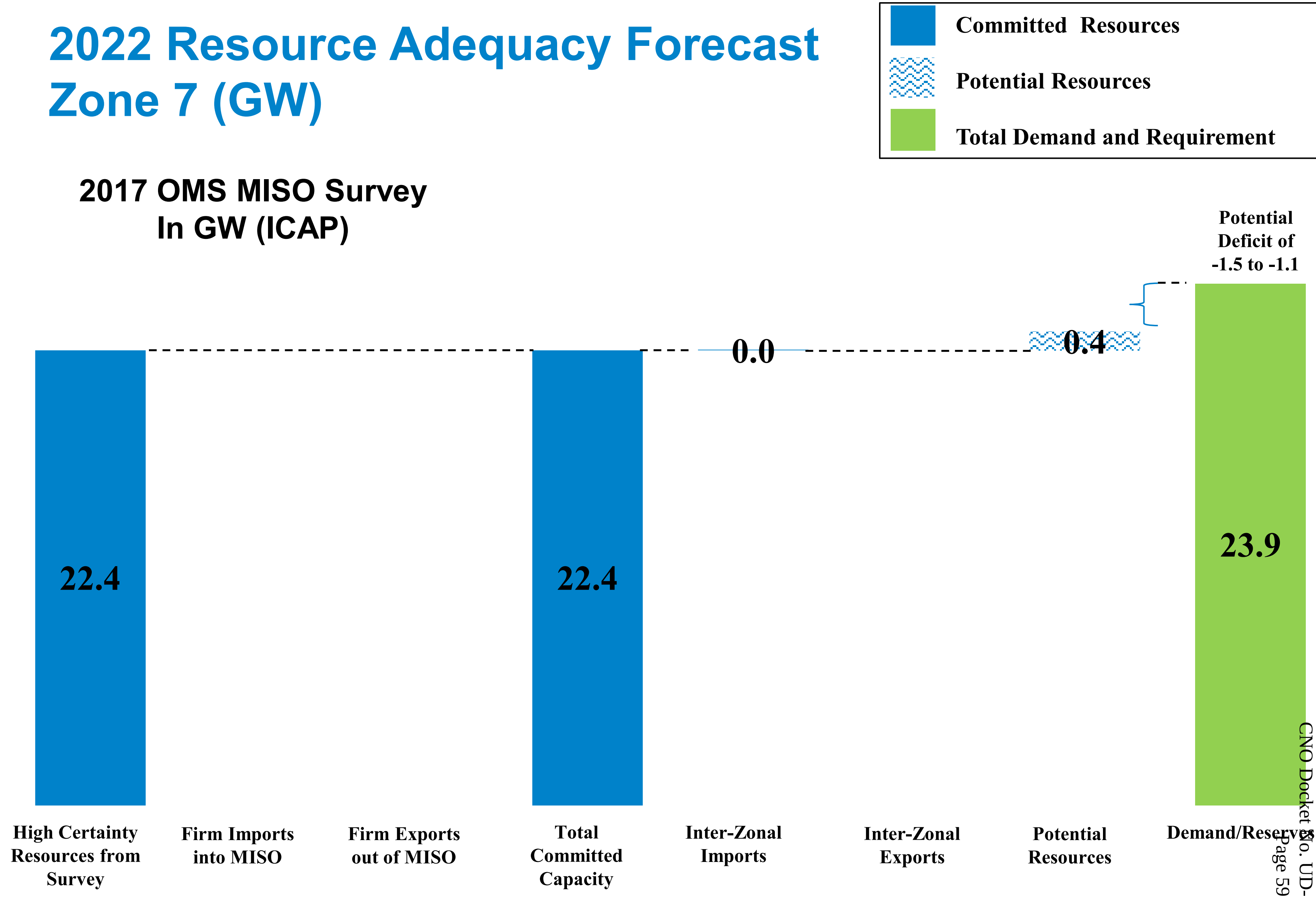
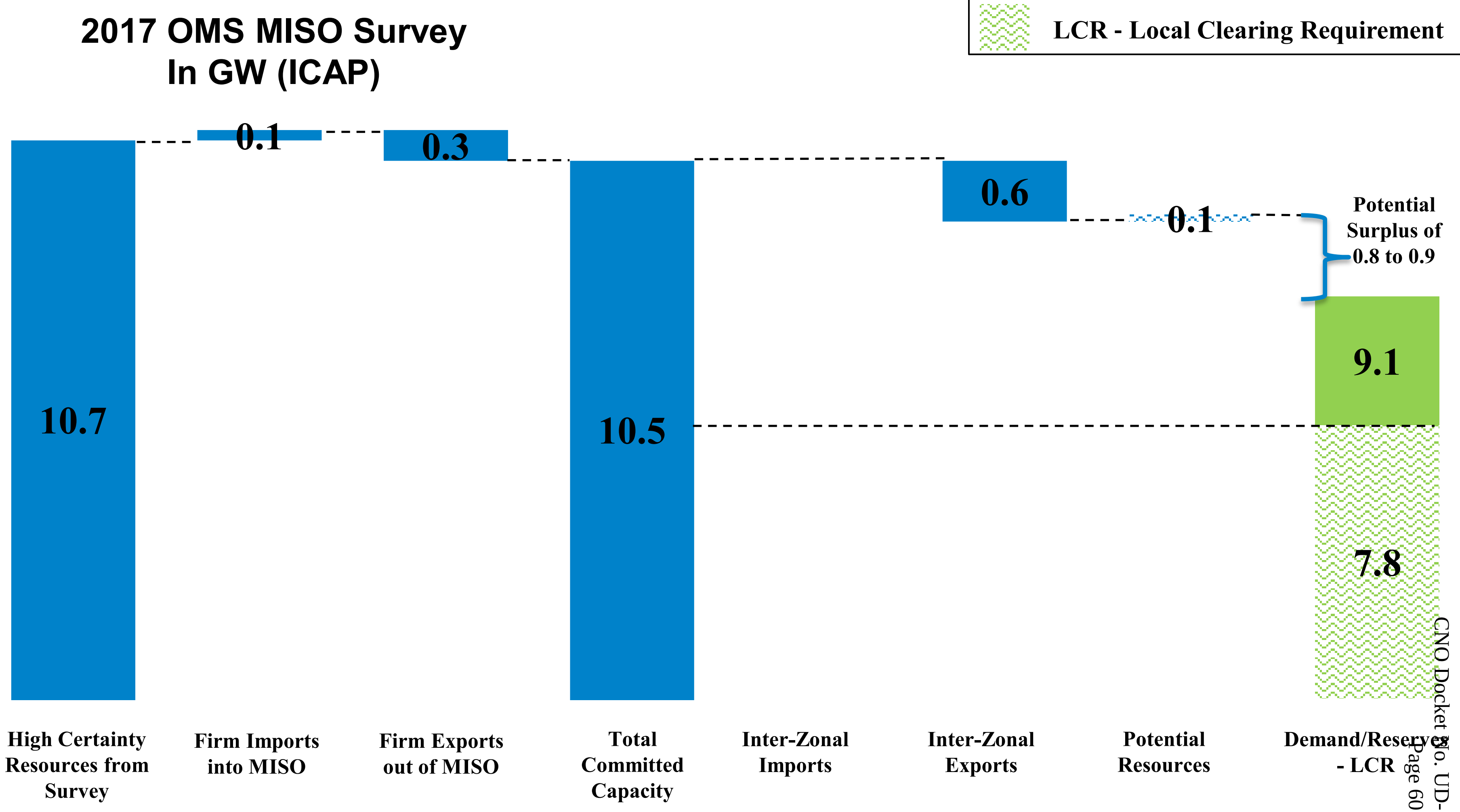
2022 Resource Adequacy Forecast Zone 7 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 8 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 8 (GW)

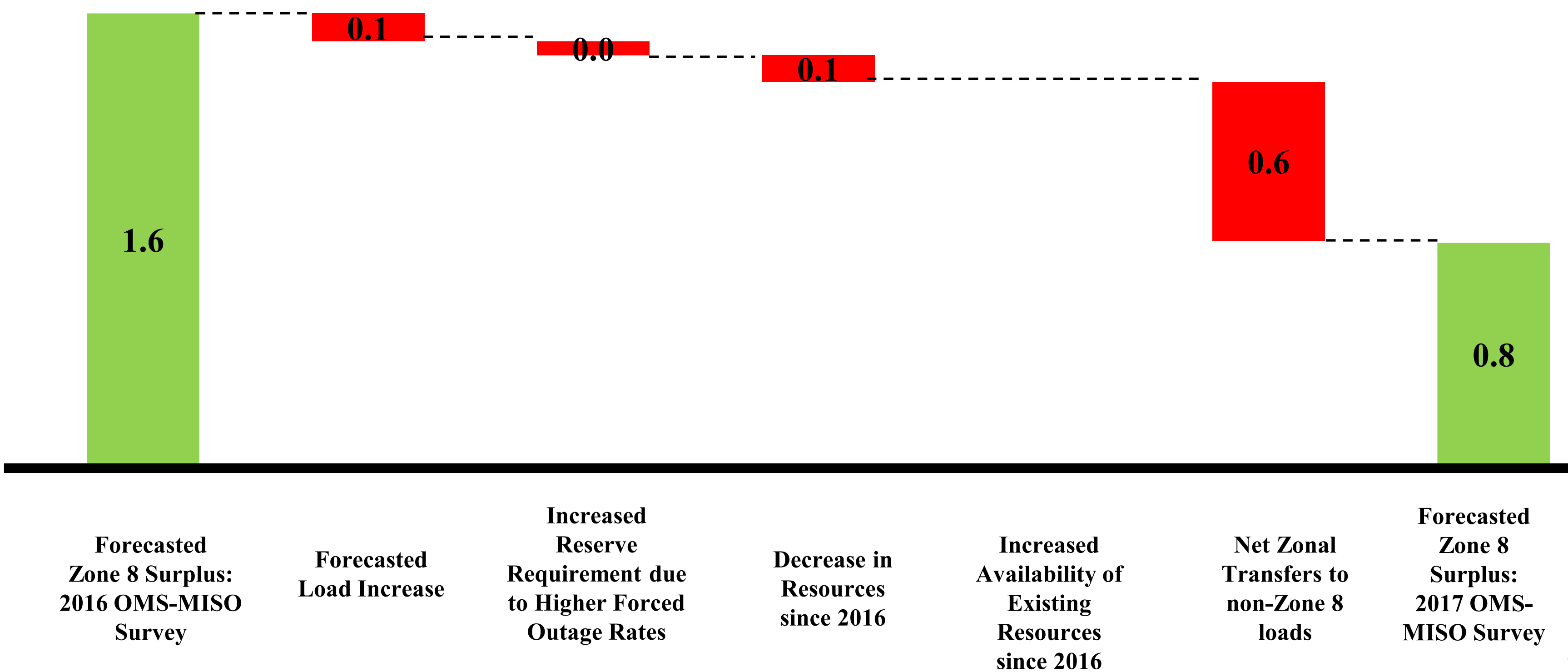
2017 OMS MISO Survey

Values In GW (ICAP)

Zone 8	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	10.8	10.8	10.8	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.3	0.3	0.3	C
Total High Certainty Capacity	**10.6**	**10.6**	**10.6**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.6	0.6	0.6	F
Demand/Reserves	**9.2**	**9.3**	**9.3**	G
Firm Capacity Position	**0.8**	**0.7**	**0.7**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.3	0.3	I
Potential Capacity Surplus/Deficit	**1.1**	**1.0**	**1.0**	J =(H+I)

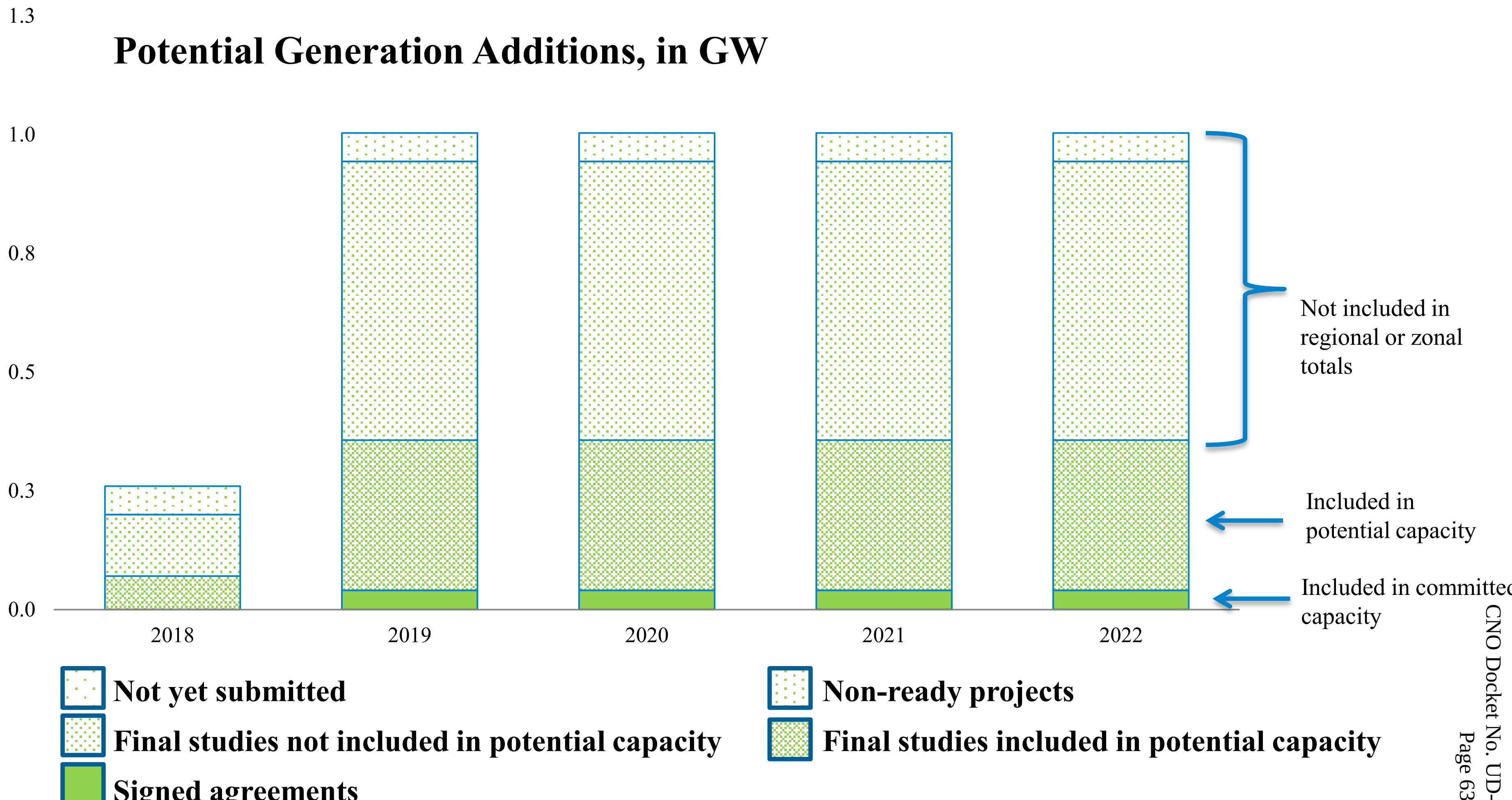
2016 vs 2017 OMS MISO Survey Results
Zone 8

Zone 8 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

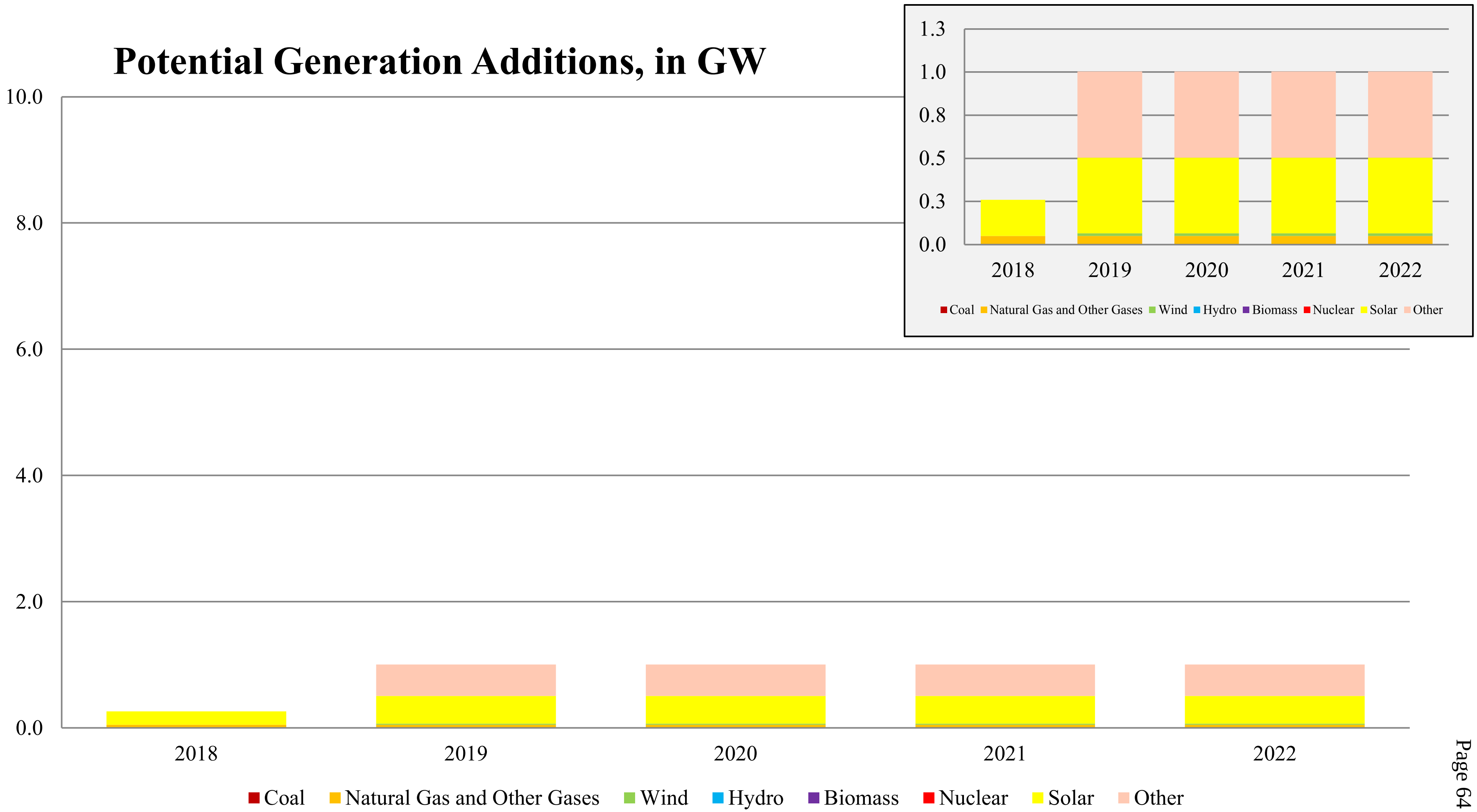
Zone 8 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

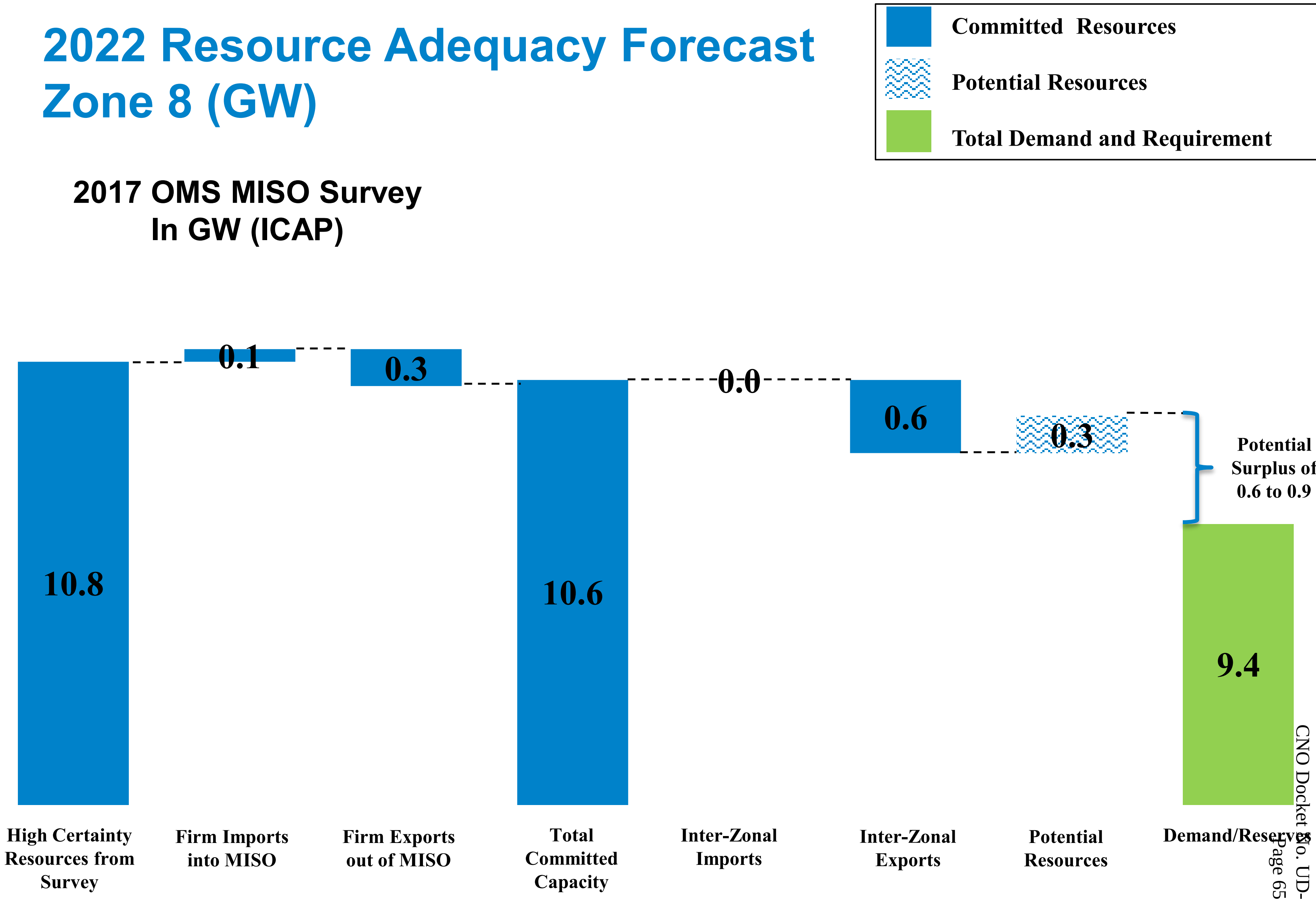
Zone 8 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

2022 Resource Adequacy Forecast Zone 8 (GW)

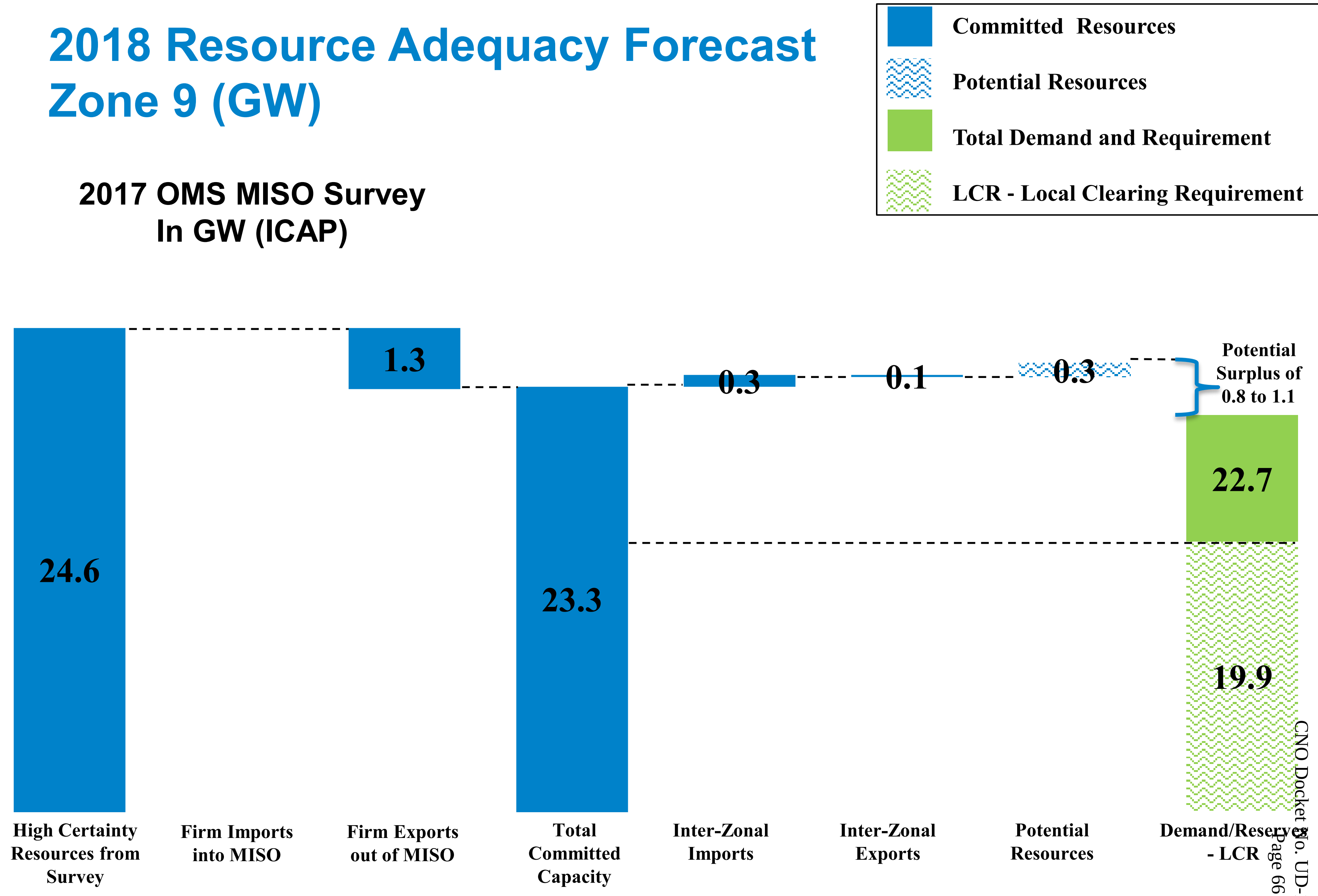
2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 9 (GW)

2017 OMS MISO Survey In GW (ICAP)



<u>Potential Resources</u> includes 35% of resources in the final study phase of the MISO Interconnection Queue

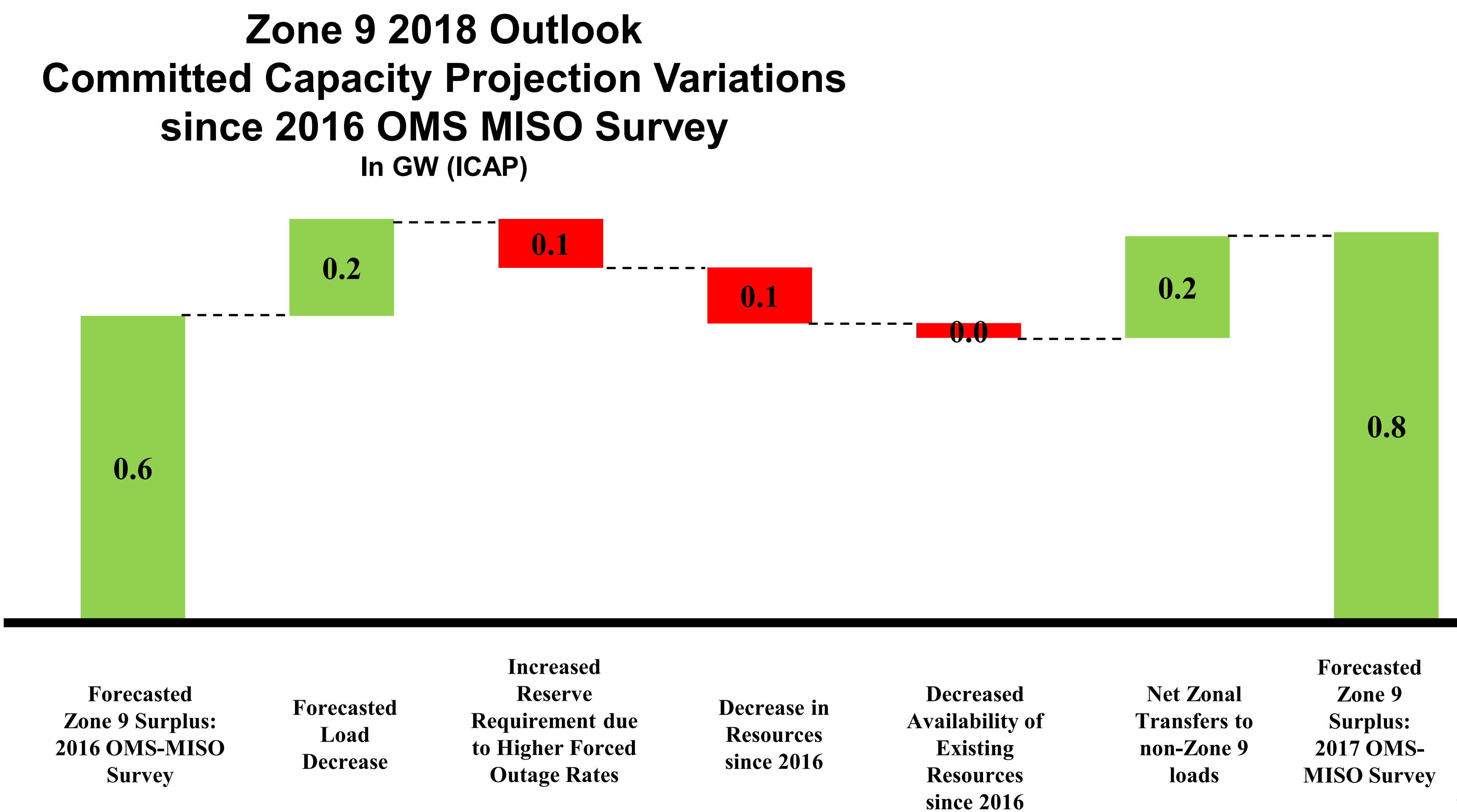
2019 - 2021 Resource Adequacy Forecast Zone 9 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

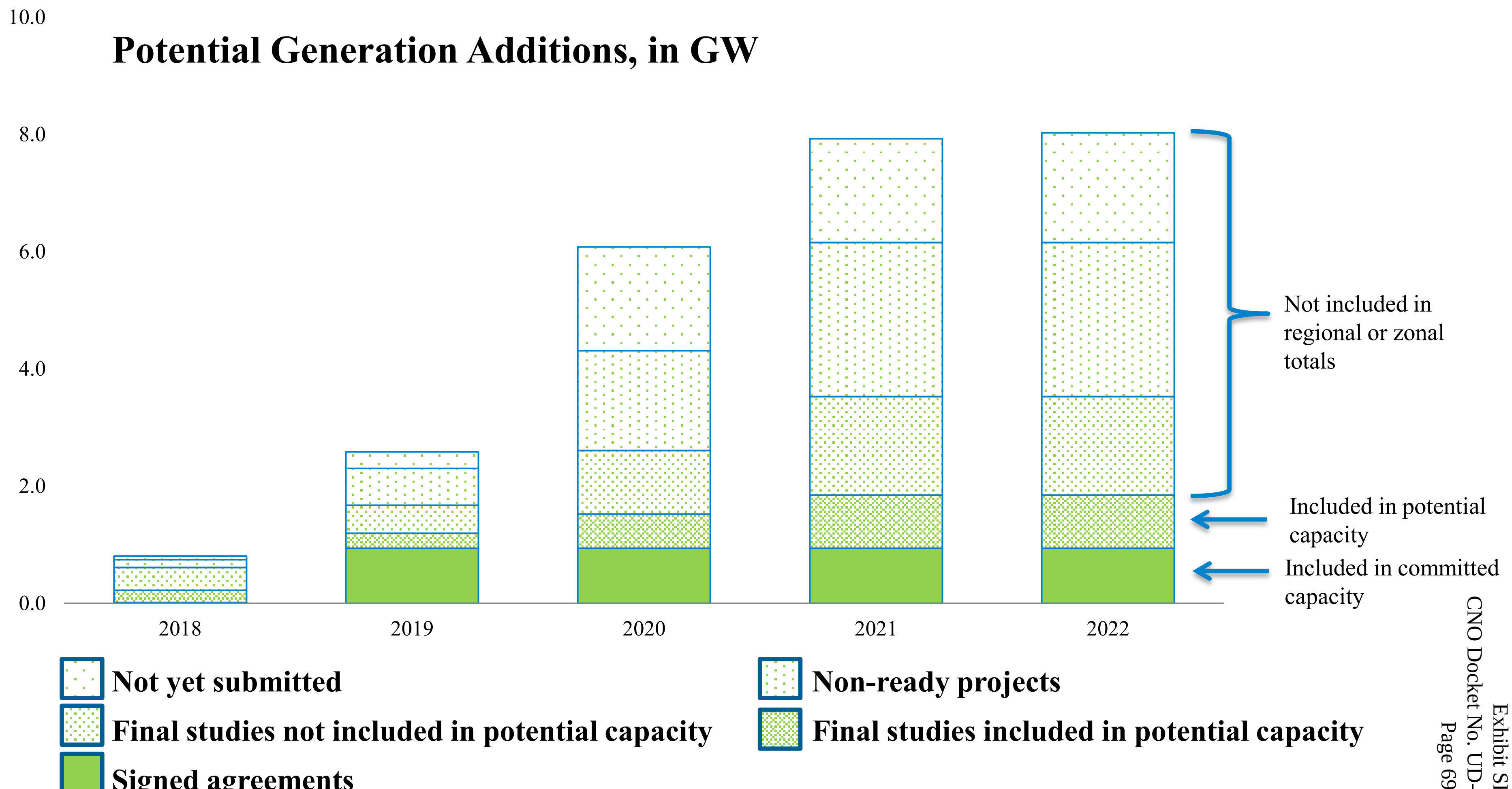
Zone 9	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	25.4	25.4	25.4	A
Firm Imports into MISO	0.0	0.0	0.0	B
Firm Exports out of MISO	1.3	1.3	1.3	C
Total High Certainty Capacity	**24.1**	**24.1**	**24.1**	D = (A+B)-C
Inter-Zonal Imports	0.3	0.3	0.3	E
Inter-Zonal Exports	0.1	0.0	0.0	F
Demand/Reserves	**22.8**	**23.0**	**23.2**	G
Firm Capacity Position	**1.5**	**1.4**	**1.2**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.7	1.0	I
Potential Capacity Surplus/Deficit	**1.8**	**2.1**	**2.2**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 9



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

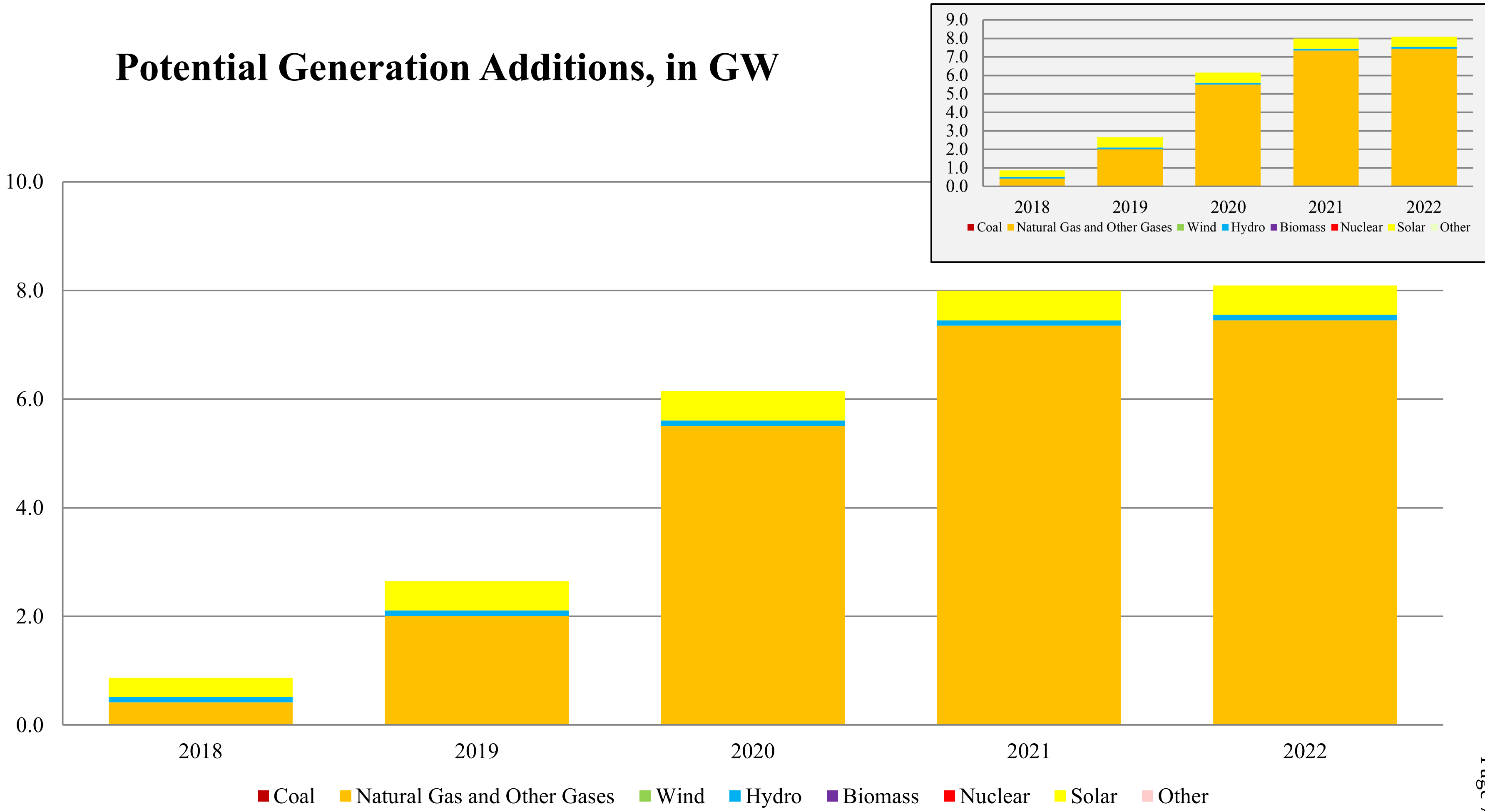
Zone 9 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 9 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
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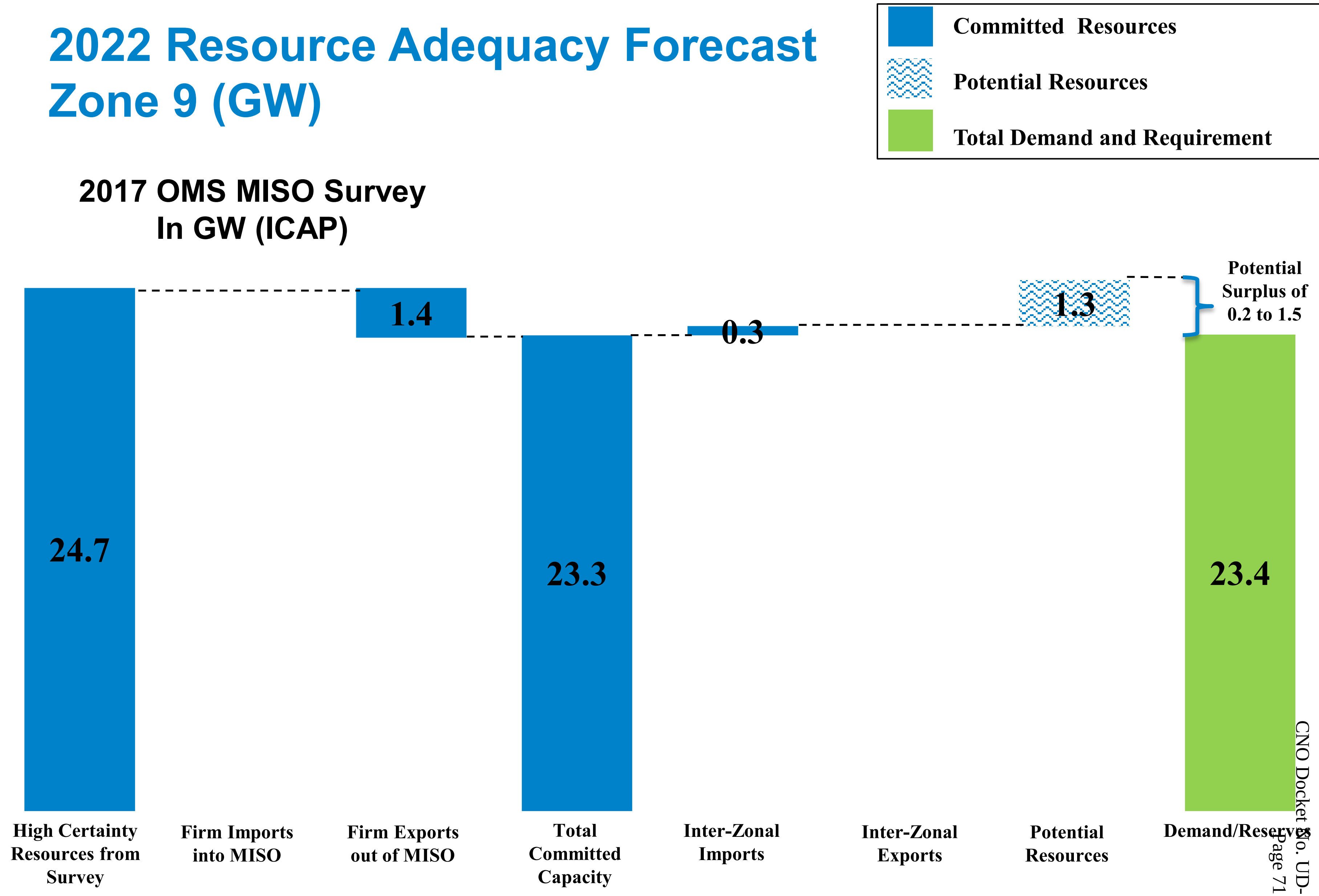
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

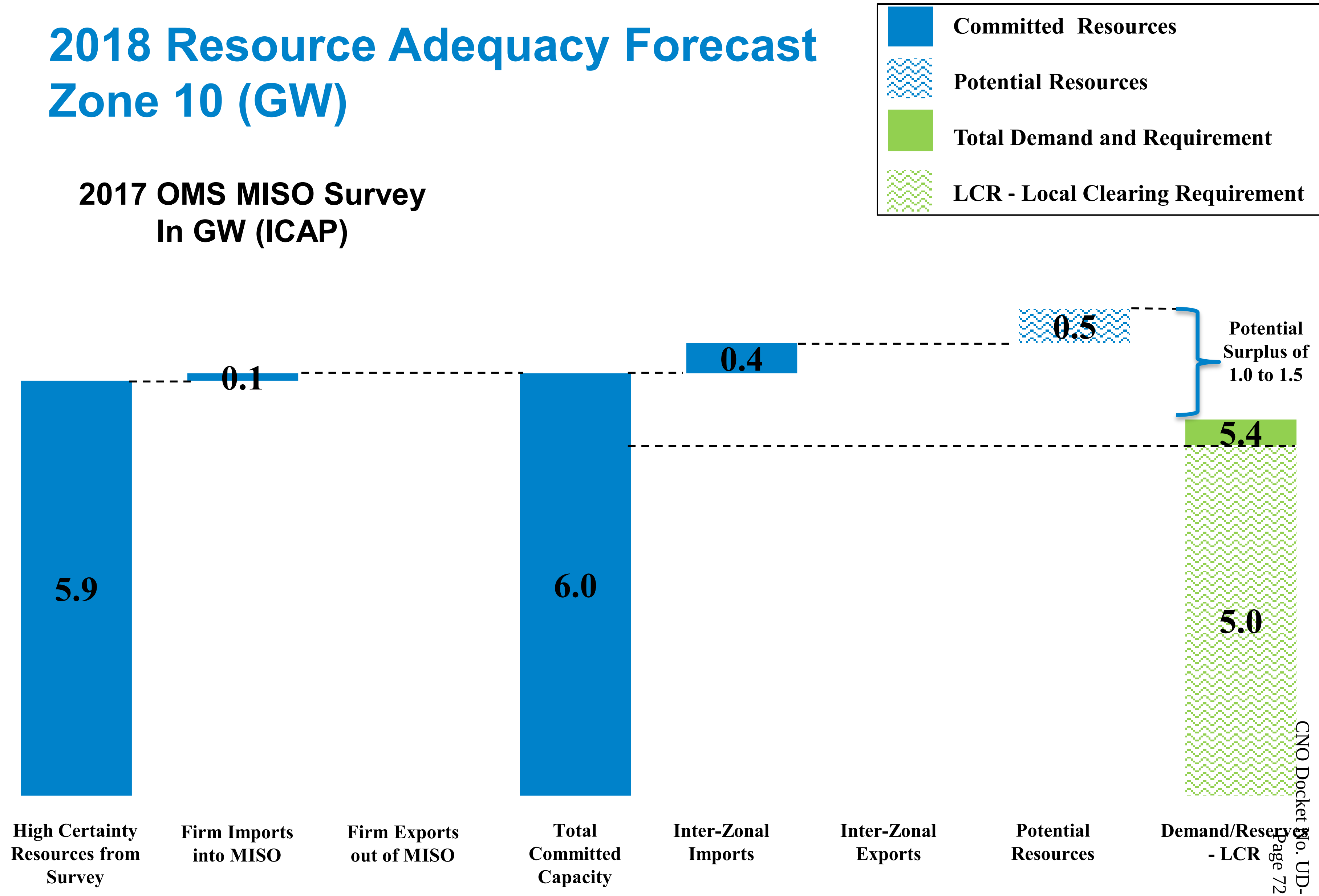
2022 Resource Adequacy Forecast Zone 9 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 10 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

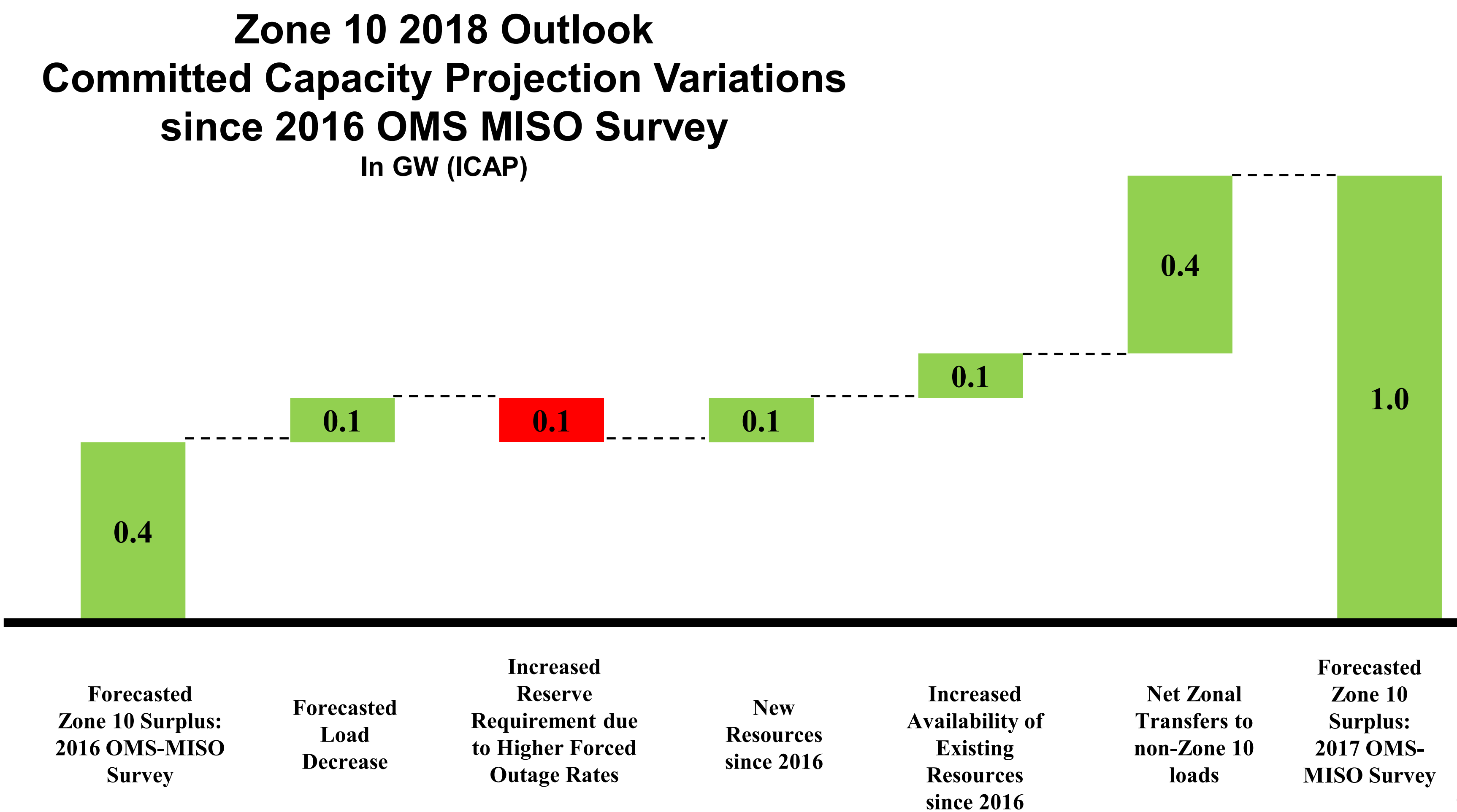
2019 - 2021 Resource Adequacy Forecast Zone 10 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

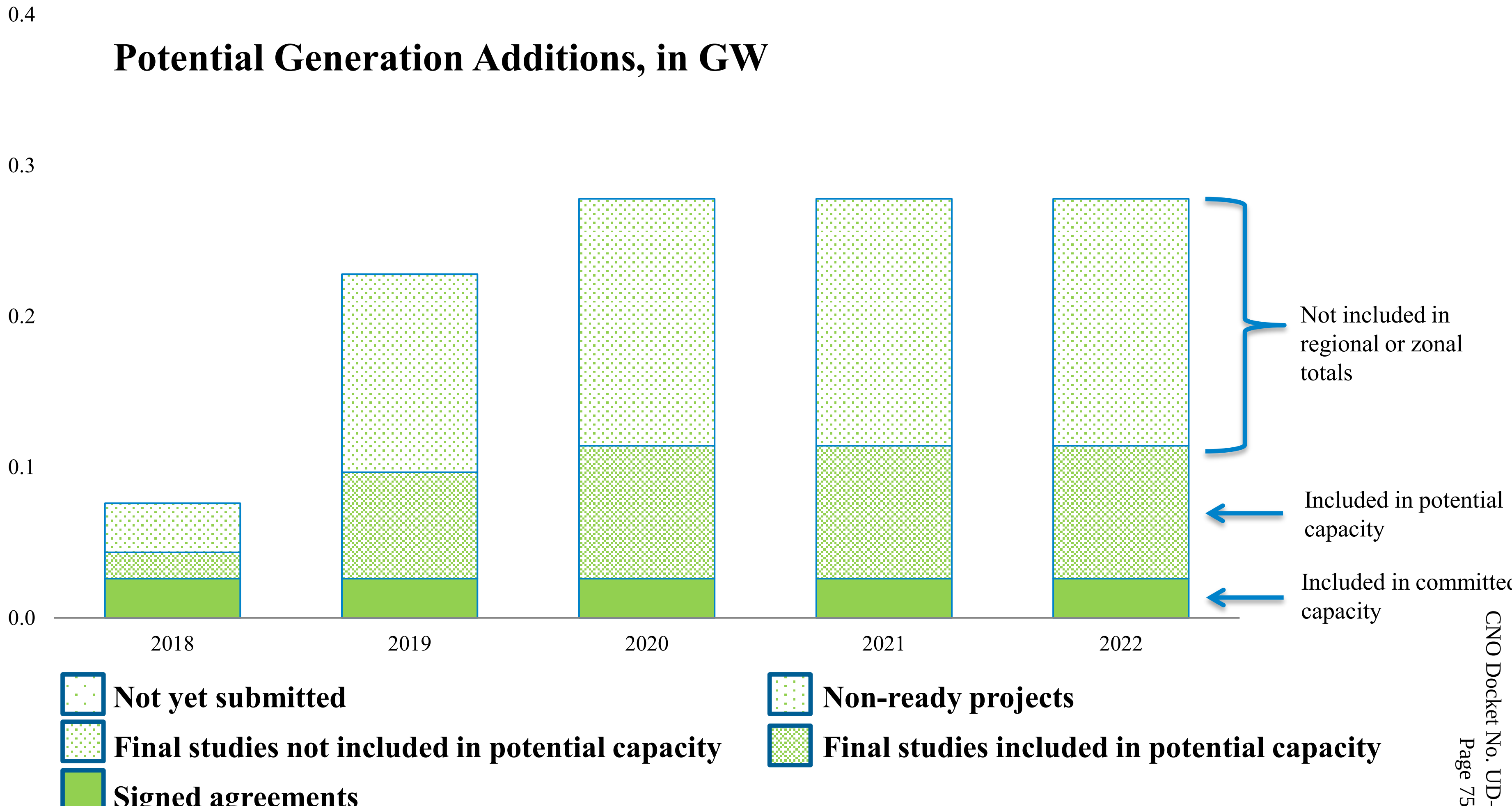
Zone 10	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	5.7	5.7	5.7	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**5.8**	**5.8**	**5.8**	D = (A+B)-C
Inter-Zonal Imports	0.4	0.4	0.4	E
Inter-Zonal Exports	0.1	0.1	0.1	F
Demand/Reserves	**5.4**	**5.4**	**5.4**	G
Firm Capacity Position	**0.8**	**0.7**	**0.7**	H =(D+E-F)-G
Low Certainty Resources	0.8	0.8	0.8	I
Potential Capacity Surplus/Deficit	**1.5**	**1.5**	**1.5**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 10



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

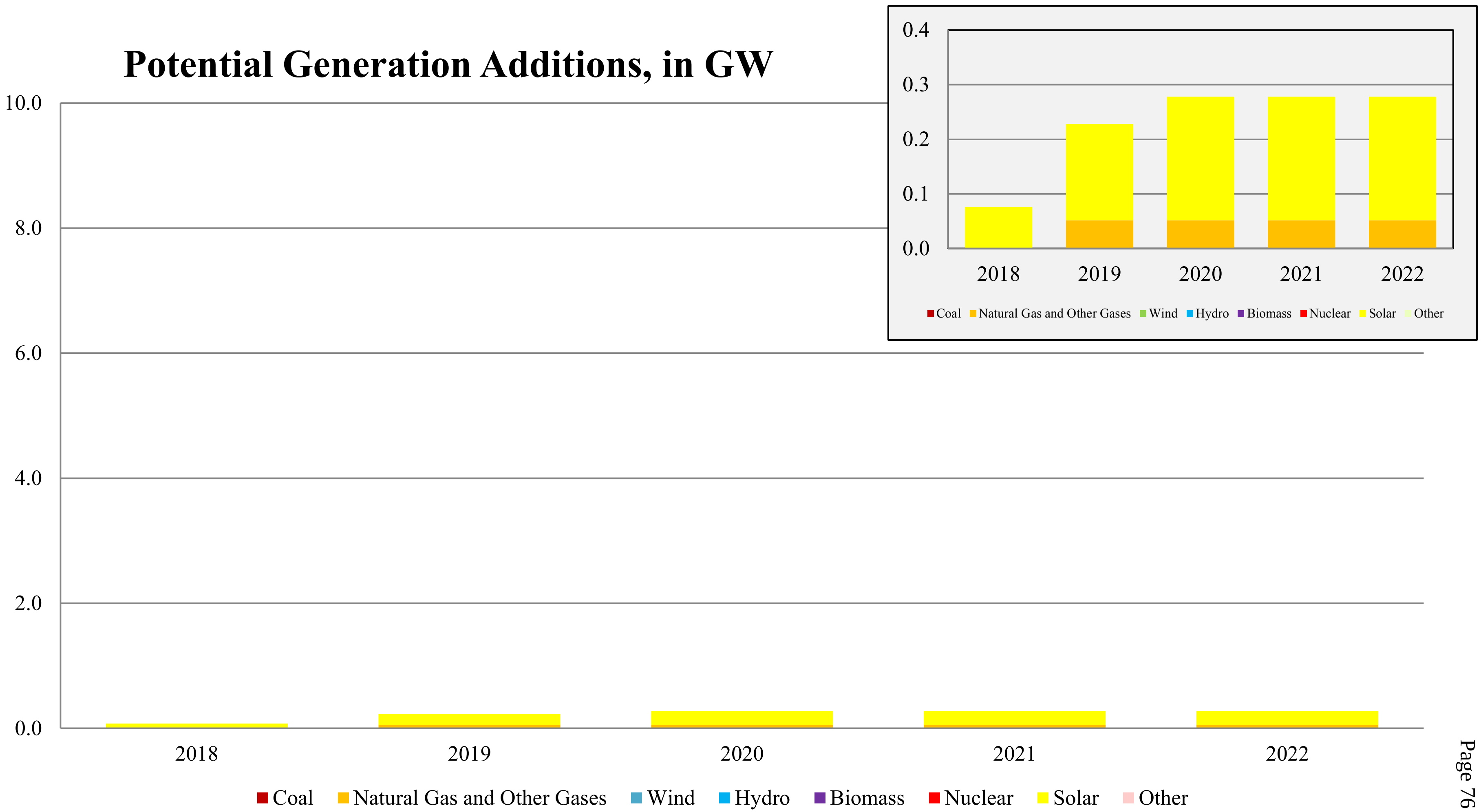
Zone 10 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 10 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

MTEP17

MISO Transmission Expansion Plan

MTEP17 REPORT

Book 2

December 2017

Table of Contents

Book 2 / Resource Adequacy

Section 6: Resource Adequacy Intro and Enhancements

6.0 Resource Adequacy Introduction and Enhancements

MISO's ongoing goal is to support the achievement of Resource Adequacy — to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during peak times and at just, reasonable rates. The responsibility for Resource Adequacy does not lie with MISO, but rather rests with Load Serving Entities and the states that oversee them (as applicable by jurisdiction). Additional Resource Adequacy goals include maintaining confidence in the attainability of Resource Adequacy in all time horizons, building confidence in MISO's Resource Adequacy assessments and providing sufficient transparency and market mechanisms to mitigate potential shortfalls.

Five guiding principles provide the framework necessary to achieve these goals.

1. Resource Adequacy processes must ensure confidence in Resource Adequacy outcomes in all time horizons
2. MISO will work with stakeholders to ensure an effective and efficient Resource Adequacy construct with appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities
3. MISO will determine adequacy at the regional and zonal level and provide appropriate regional and zonal Resource Adequacy transparency and awareness for multiple forward time horizons
4. MISO will administer and evolve processes in a manner that provides transparency and reasonable certainty, appropriately protects individual market participant proprietary information in order to support efficient stakeholder resource and transmission investment decisions
5. MISO's resource planning auction and other processes will support multiple methods of achieving and demonstrating Resource Adequacy, including self-supply, bilateral contracting and market-based acquisition.

To date, the Resource Adequacy process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation (LOLE) analysis, the Planning Resource Auction, and the Organization of MISO States-MISO Survey. With the resource portfolio now evolving due to coal retirements and the increase in gas-fired generation, MISO is evaluating the Resource Adequacy requirements. This evaluation has led to an evaluation of the MISO processes, with focuses on:

- Aligning treatment of external and internal resources
- Ensuring LOLE assumptions align with Planning Resource Auction inputs
- Visibility into non-summer resource adequacy risk

6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM ICAP) for the 2017-2018 planning year, spanning from June 1, 2017, through May 31, 2018, is 15.8 percent, an increase of 0.6 percentage points from the 15.2 percent PRM set in the 2016-2017 planning year (Figure 6.1-1).

The PRM ICAP is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.6 percentage point PRM ICAP increase was the net effect of an increase in forced outage rates and reduction in load forecasts.

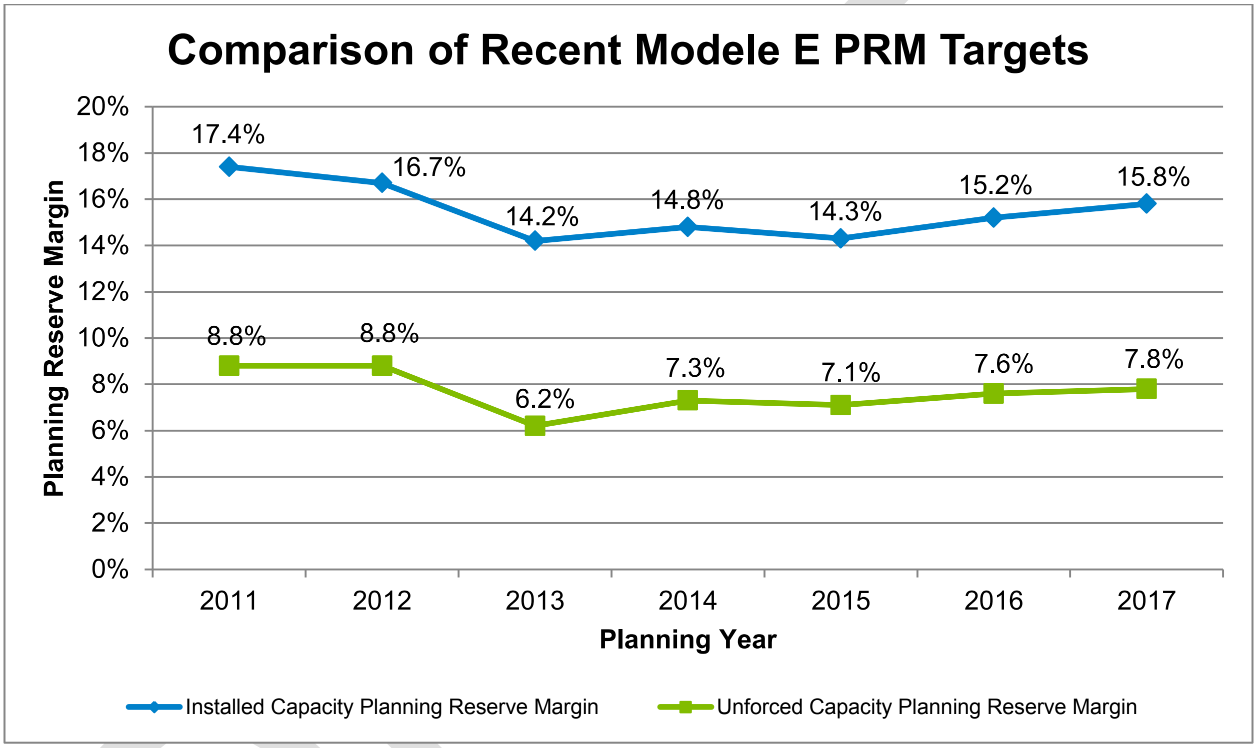


Figure 6.1-1: Comparison of recent PRM

As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate Planning Reserve Margin (PRM) for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study and the deliverables from the Loss of Load Expectation Working Group (LOLEWG) are based on the Resource Adequacy construct per Module E-1. MISO performs an annual LOLE study to determine the congestion-free PRM on an installed and unforced capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined for each

Local Resource Zone (LRZ) (Figure 6.1-2), which is defined as the amount of resources a particular area needs to meet the LOLE criteria of one day in 10 years without the benefit of importing capacity. These results are merged with the Capacity Import Limit (CIL), Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.

Figure 6.1-2: Local Resource Zones (LRZ)

2017-2018 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM UCAP, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1).

The PRM UCAP[1] increased from 7.6 percent in the 2016-2017 LOLE report to 7.8 percent in the 2017-2018 LOLE report due to the modeling parameter changes. More information on the increase is available in the 2017 LOLE report[2]. Under the existing construct, the PRM UCAP is applied to the peak of each Load Serving Entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). Adjustments were made to CIL based on a December 31, 2015 FERC order to reflect resources committed to non-MISO load. The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the resources cleared in the auction can be reliably delivered.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
LRR UCAP per-unit of LRZ Peak Demand	1.113	1.117	1.125	1.228	1.218	1.117	1.141	1.258	1.118	1.412
Capacity Import Limit (CIL) (MW)	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910
Capacity Export Limit (CEL) (MW)	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747

Table 6.1-1: Deliverables to the 2016-2017 Planning Resource Auction (PRA)

[1] PRM UCAP is the value accounting for the forced outage rate of capacity. More information on this calculation may be found in the LOLE report.
[2] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf

LRZ	Tier	17-18 Limit (MW)[3]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)[4]	Generation Redispatch (MW)	16-17 Limit (MW)
1	1	3,531	Point Beach to Kewaunee 345 kV	Fox River to North Appleton 345 kV	1	2,940	2,000	3,436
2	1	2,227	Stoneman to Nelson Dewey 161 kV	Seneca to Genoa 161 kV	2	553	2,000	1,609
3	1	2,408	Sub 3458 to Sub 3456 345 kV	Sub 3455 to Sub 3740 345 kV	3	1,876	550	1,886
4	1 & 2	5,815	Meredosia to Jacksonville Industrial Park 138 kV	Ballard – Meredosia 138 kV	4	3,658	0	6,323
5	1	4,096	Sikeston to Idalia 161 kV	Essex – New Madrid 345 kV	5	2,559	1,689	4,837
6	1 & 2	6,248	Cayuga – Cayuga sub 345 kV	Rockport to Jefferson 765 kV	6	N/A		5,610
7	N/A	3,320	Brownstown 345 kV Bus	Monroe – Wayne 345 kV	7	N/A		3,521
8	1	3,275	Colonial Orange to Cow 138 kV	Sabine to Cow 500 kV: 138 kV	8	2,340	826	3,527
9	1	3,371	Bogalusa 500/230 kV	McKnight to Franklin 500 kV	9	2,169	1,756	4,490
10	1	1,910	Freeport to Twinkletown 230 kV	Freeport to Horn Lake 230 kV	10	1,594	1,984	2,653

Table 6.1-2: 2017-2018 Planning Year Capacity Import Limits

[3] The 17-18 Limit represents the limit after redispatch has been considered
[4] The Initial Limit represents the limit before considering redispatch.

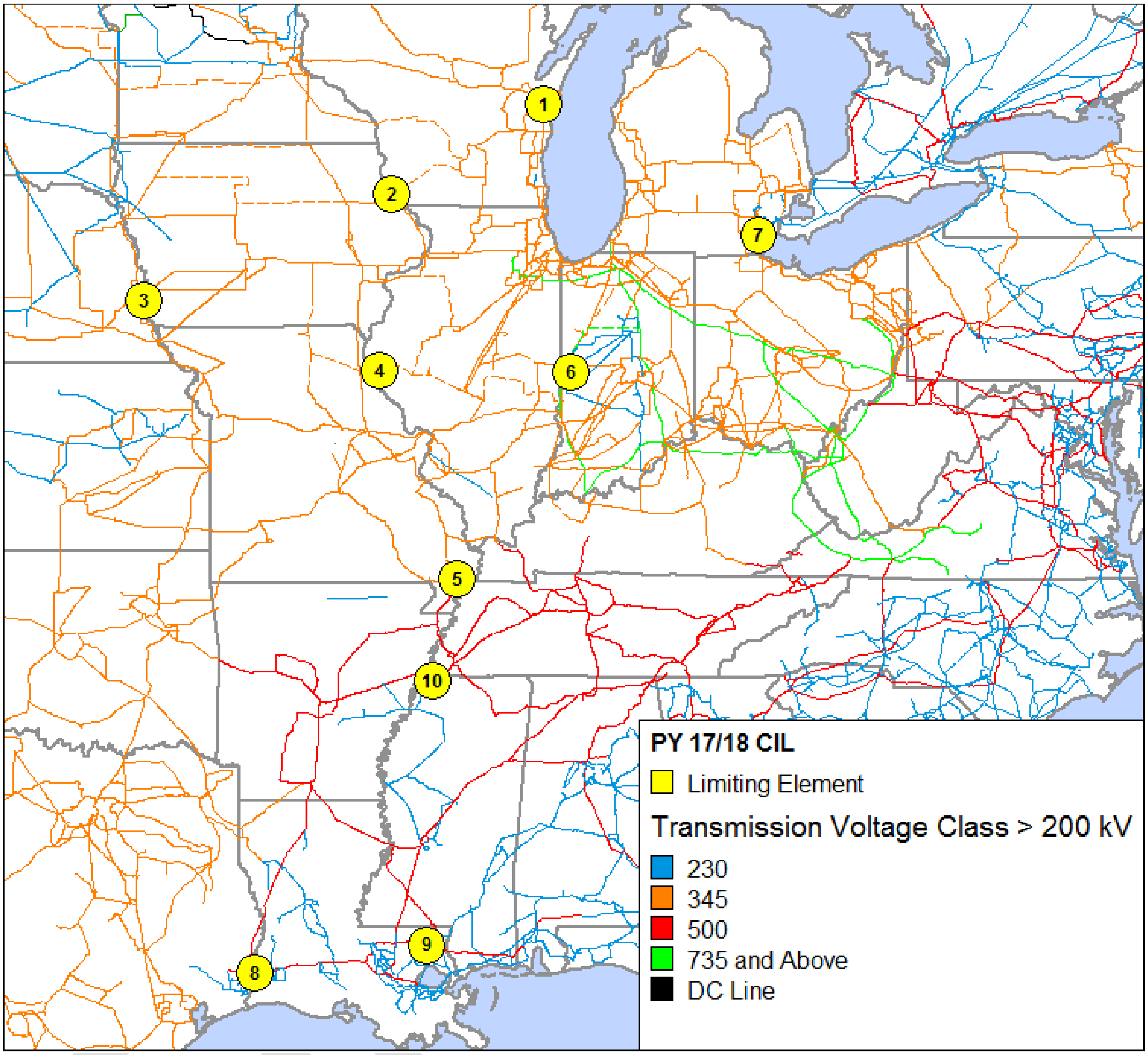


Figure 6.1-3: 2017-2018 Capacity Import Limit map

LRZ	17-18 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	Initial Limit (MW)	Generation Redispatch (MW)	16-17 Limit (MW)
1	686	Lakefield to Dickinson 161 kV	Lakefield to Obrien 345 kV	1	0	1,674	590
2	2,290	Sherman Street to Sunny Vale 115 kV	Arpin to Rocky Run 345 kV	2	N/A		2,996
3	1,772	Colby to Northern Iowa Wind 161 kV	Adams to Barton 161 kV	3	497	1,362	1,598
4	11,756	No transmission constraint identified	N/A	4	N/A		7,379
5	2,379	Peno Creek to Marion Tap 161 kV	Maywood to Spencer Creek 345 kV	5	N/A		896
6	3,191	Stout CT to Southwest 138 kV	Stout North to Stout CT 138 kV	6	N/A		2,544
7	2,519[5]	Custer to Whiting 120 kV	Lulu – Morocco – Milan 345 kV	7	N/A		4,541
8	2,493	Catherine to Arklahoma 115 kV	Base Case	8	2,289	1,126	2,074
9	2,373	Cow to Colonial Orange 138 kV	Sabine to Cow 500 kV	9	1,422	1,686	1,261
10	1,747	Batesville to Tallahatchie 230/115 kV	Choctaw to Clay 500 kV	10	890	1,540	1,857

Table 6.1-3: 2017-2018 Planning Year Capacity Export Limits

[5] Rating of limiting element increased since initiation of LOLE study. Limit reflects export capability considering new rating identified after completion of LOLE study prior to the auction.

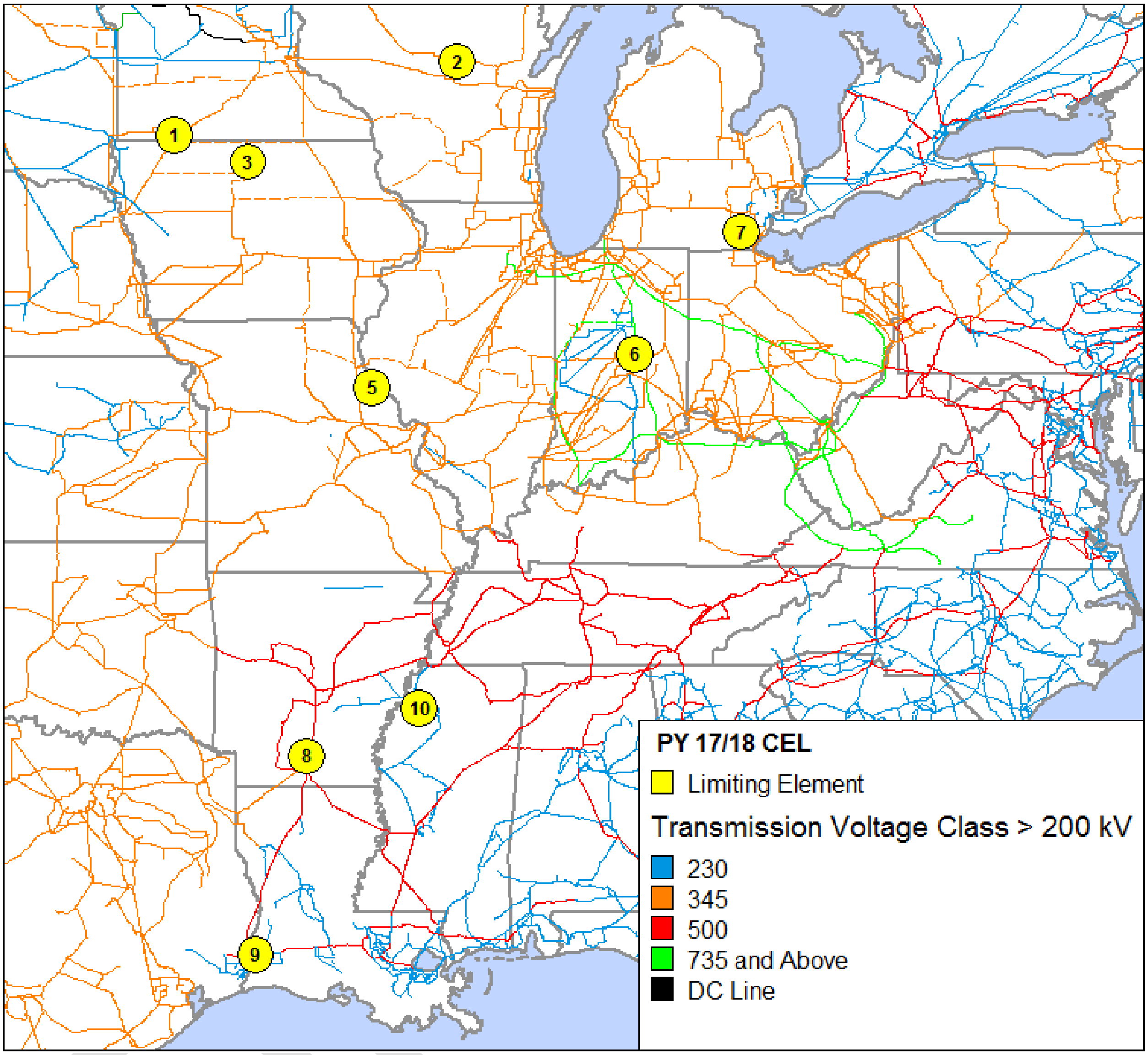


Figure 6.1-4: 2017-2018 Capacity Export Limit map

MTEP Projects and Capacity Import and Export Limits

The Capacity Import and Export Limits are deliverables to the Planning Resource Auction (PRA) and, in combination with the Local Clearing Requirement (LCR), determine the maximum amount of imports or exports allowed for a zone. Constraints may occur in the PRA when the imports or exports are limited by the CIL, CEL, and LCR. These constraints are considered in the development of the MTEP. Table 6.1-4 outlines projects impacting LCR, CIL or CEL that impact limits that have bound in the previous two Planning Resource Auctions.

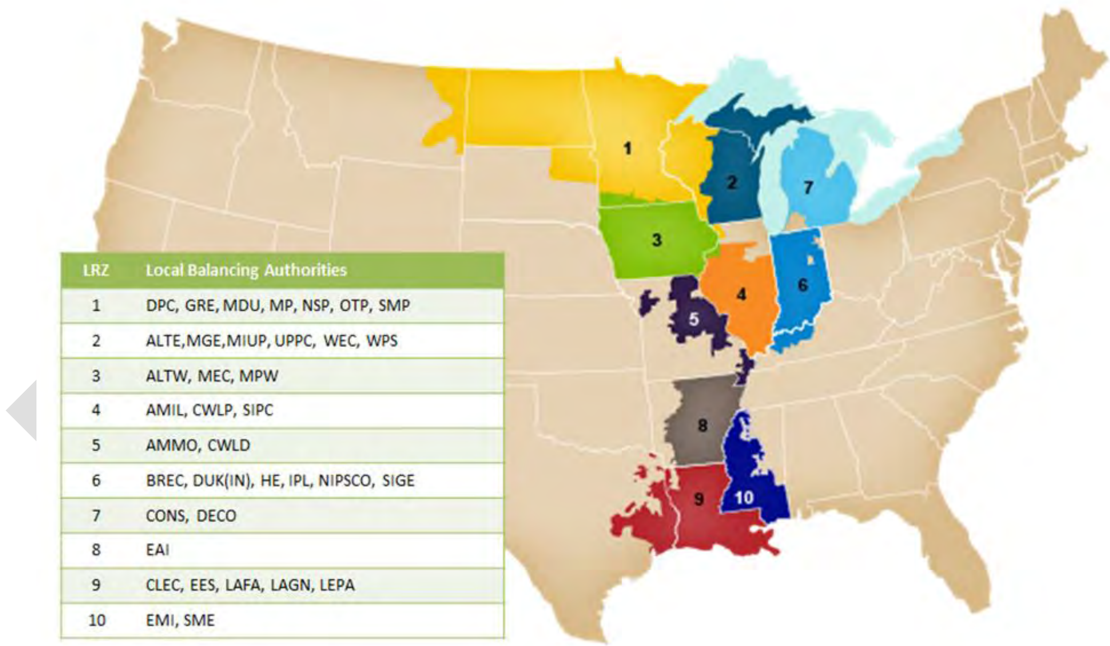
LRZ	CEL or CEL	Monitored Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
1	CEL	Lakefield to Dickinson 161 kV Line	3205, 3213	A in MTEP11	Proposed MVP Portfolio 1: Lakefield Jct. – Winnebago – Winco – Kossuth County and Obrien County – Kossuth County – Webster 345 kV line and Proposed MVP Portfolio 1 – Winco to Hazleton 345 KV line	9/28/2015 – 6/1/2018, 6/1/2015 – 12/31/2018

Table 6.1-4: MTEP project impacting CEL which has bound in the PRA

For full details of the LOLE study, refer to the Planning Year 2017 LOLE study report.

Wind Capacity Credit

A class-average wind capacity credit of 15.6 percent was established for the 2017-2018 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit remained the same from the wind capacity credit of 15.6 percent established in the 2016-2017 Planning Year (Figure 6.1-5). For more information, refer to the complete 2017 Wind Capacity Credit Report[6].



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	15,910	4,703	636	7,853	644	282	1,792	0	0	0
UCAP (MW)	2,482	861	88	1,214	67	25	226	0	0	0
ELCC %	15.6%	18.3%	13.9%	15.5%	10.5%	8.8%	12.6%	0.0%	0.0%	0.0%
Wind CPnode Count	204	72	10	84	8	4	26	0	0	0

Figure 6.1-5: Wind Capacity Credit by Local Resource Zones (LRZ) for 2017-2018 Planning Year

[6] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20Wind%20Capacity%20Report.pdf

Solar Capacity Credit

A class-average solar capacity credit of 50 percent was established for the 2017-2018 planning year by estimating the peak period contribution from historical solar irradiance simulation data. New resources without summer operating history will receive this class average capacity credit until at least 30 consecutive days of summer performance data are available, at which time the resource's individual capacity credit will be based on its own operating history. More details can be found in the MISO BPM-011 in section 4.

6.2 Long-Term Resource Assessment

The Long-Term Resource Assessment (LTRA) examines the balance between projected resources and the projected load. These resources are compared with Planning Reserve Margin Requirements (PRMR) to calculate a projected surplus or shortfall.

MISO forecasts sufficient capacity resources to meet expected demand and reserves for the next five years, above the Planning Reserve Margin Requirement (PRMR) of 15.8 percent. Beginning in 2023 MISO capacity is projected to fall below the PRMR and remain there for the rest of the assessment period (Table 6.2-1). Falling below the PRMR signifies that the MISO region is projected to operate at a reliability level lower than the one-day-in-10 standard in 2023 and beyond. The LTRA results represent a point in time forecast, and MISO anticipates the projected margins will change significantly as Load Serving Entities and state commissions solidify future capacity plans.

This is an expected result, as 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need (CPCN).

In GW (ICAP)	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28
(+) Existing Resources	150.0	149.3	148.9	148.6	146.7	145.0	144.7	144.2	144.0	144.0
(+) New Resources	2.0	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
(+) Imports	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.1	3.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
(-) Low Certainty Resources	1.0	1.1	1.4	1.5	1.5	2.3	2.3	2.4	2.4	2.4
(-) Transfer Limited	2.5	2.3	2.1	1.8	1.1	0.0	0.0	0.0	0.0	0.0
Available Resources	148.5	150.4	150.3	150.4	149.2	147.8	147.5	147.0	146.8	146.8
Demand	125.9	126.5	127.0	127.6	128.3	128.9	129.4	129.1	128.9	128.9
PRMR	145.8	146.5	147.1	147.8	148.5	149.2	149.9	149.5	149.3	149.3
PRMR Surplus / Shortfall	2.7	3.9	3.2	2.6	0.6	-1.4	-2.4	-2.5	-2.5	-2.5
Reserve Margin Percent (%)	17.9%	18.9%	18.3%	17.9%	16.3%	14.7%	14.0%	13.9%	13.8%	13.8%

Table 6.2-1: MISO projected PRMR details (cumulative)

MISO projects a regional surplus for the summer of 2018, and continuing on through the summer of 2022. These results show a regional surplus instead of the deficit from the 2016 MISO LTRA results, including uncommitted resources.

Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in the use of Load Modifying Resources (LMR), such as Behind-the-Meter Generation (BTMG) and Demand Response (DR).

In 2018, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak.

The conclusions from the long-term resource assessments are:

- An increase in resources committed to serving MISO load mainly by independent power producers (IPP).
- Lower demand-growth forecasts across most zones in MISO.
- The increase in committed resources from BTMG and Demand Response.
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their Local Clearing Requirements, or the amount of their local resource requirement, which must be contained within their boundaries.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; also MISO is engaged with stakeholders in a number of Resource Adequacy reforms to help rectify these out year shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the reserve margin requirement.

Assumptions

At the end of 2013 MISO and Organization of MISO States (OMS) conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the fourth iteration of the OMS-MISO survey in June 2017, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2018, MISO anticipates that the MISO Region's coincident demand will be 125,921 MW, which is a 50/50 weather-normalized load forecast.

Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.3 percent for the period from 2018 to 2028.

In 2018, MISO anticipates that the MISO Region's coincident demand will be 125,921 MW, which is a 50/50 weather-normalized load forecast.

Resources

In 2018, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak.

MISO's current generation capacity (nameplate) of 174,724 MW steps down to Existing-Certain Capacity Resources of 139,200 MW by accounting for summer on-peak generator performance (including wind capacity at 15.6 percent of nameplate and solar at 50 percent of nameplate), transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 139,200 MW towards its PRMR to meet a loss-of-load expectation of one day in 10 years.

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency

Operating Procedures. MISO assumes the 4,129 MW of BTMG increasing to 4,169 in 2022 and 5,620 MW of LMR DR that was qualified in the 2017 Planning Resource Auction to be available throughout the assessment period.

In the 2017 MISO-OMS survey, resources that were identified to have a low certainty of serving load were not included (Figure 6.2-1).

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 4,517 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period (Figure 6.2-1). This is based on a snapshot of the GIQ as of June 2017 and is the aggregation of active projects with a signed Interconnection Agreement.

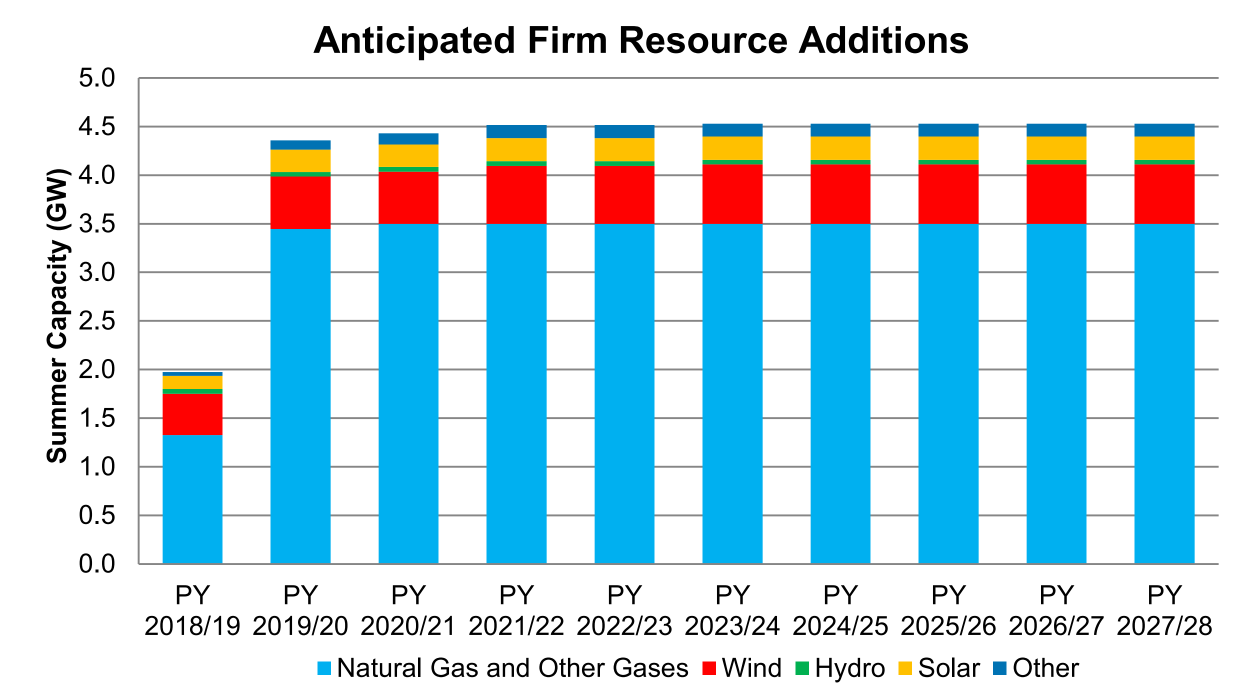


Figure 6.2-1: Anticipated Resource Additions and Uprates (Cumulative) of active projects with a signed Interconnection Agreement in the MISO Region

Imports and Exports

MISO assumes a forecast of 4,106 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider. This capacity was designated to serve load within MISO through the Module E process for summer 2018. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 4,134.7 MW of firm capacity exports in year 2018. Exports are projected to decrease to 3,600 MW in 2020 and remain at that level for the rest of the assessment period.

When comparing reserve margin percent numbers between Figure 6.2-1 and the NERC LTRA, the percent for each planning year will be slightly lower in the NERC LTRA because of differences in the reserve margin percent calculation. MISO's resource adequacy construct counts DR as a resource while the NERC calculates DR on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is comparable between the two.

6.3 Seasonal Resource Assessment

MISO conducts seasonal resource assessments for the winter months of December, January and February as well as for summer months of June, July and August. Seasonal assessments primarily evaluate the expected near-term system performance and prepare operators for the upcoming season. The MISO resource assessments coincide with NERC seasonal reliability assessments and MISO operational readiness workshops held prior to the assessment's season.

The 2016-2017 winter and 2017 summer season findings show that the projected capacity levels exceed the Planning Reserve Margin Requirement, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with expected dispatch limits, only 1,500 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios for the 2017 Summer Assessment.

MISO coordinates extensively with neighboring Reliability Coordinators as part of the seasonal assessment and outage coordination processes, via scheduled daily conference calls and ad-hoc communications as need arises in real-time operations. There is always the potential for a combination of higher loads, higher forced outage rates and fuel limitations. In the summer, unusually hot and dry weather can lead to low water levels and/or high water temperatures. This can impact the maximum operating capacity of thermal generators that rely on water resources for cooling, leading to added deratings in real time and lowering functional capacity. MISO resolves these situations through existing procedures depending on the circumstances, and several scenarios are studied for each season to project the possible reserve margins expected.

Demand

Based on 21 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2017 LOLE Study.

Demand Reporting

MISO does not forecast load for the Seasonal Resource Assessments. Instead, Load Serving Entities (LSEs) report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO Tariff. LSEs report their annual load projections on a MISO Coincident basis as well as their Non-Coincident load projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. MISO LSEs have the best information of their load; therefore, MISO relies on them for load forecast information.

For these studies, MISO created a Non-Coincident and a Coincident peak demand on a regional basis by summing the annual peak forecasts for the individual LSEs in the larger regional area of interest.

2016-2017 Winter Overview

For planning year 2016-2017, MISO's Planning Reserve Margin Requirement (PRMR) was 15.2 percent. For the 2016-2017 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 35.4 percent, which far exceeds the PRMR of 15.2 percent. The winter scenarios project the reserve margin to be in the range of 28.4 to 37.5 percent (Figure 6.3-1).

MISO's 50/50 coincident peak demand for the 2016-2017 winter season was forecasted to be 103,973 MW including transmission losses, with 140,774 MW of capacity to serve MISO load during the 2016-2017 winter season. Excluded from the capacity are 6,110 MW of MISO South resources to align with the Planning Resource Auction (PRA) Sub-Regional Export Constraint (SREC).

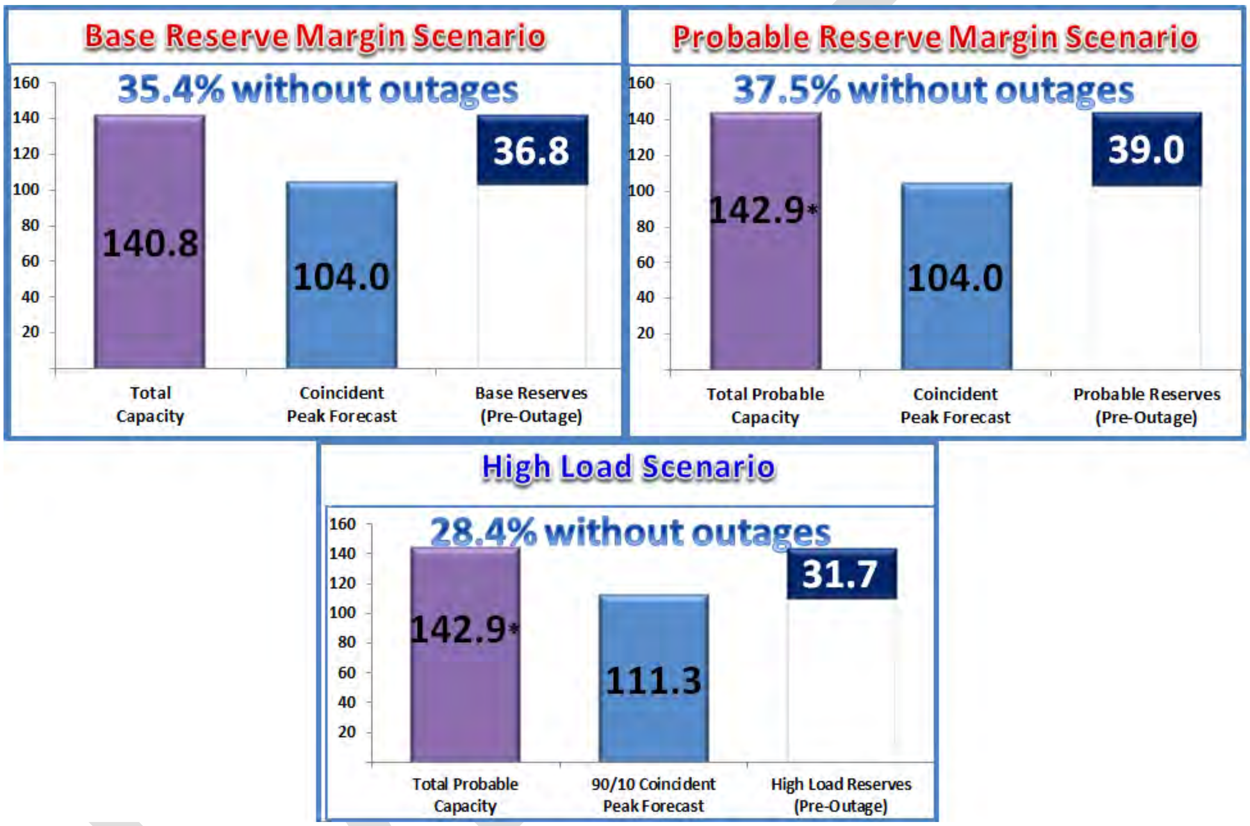


Figure 6.3-1: Winter 2016-2017 Projected Reserve Margin scenarios (GW)

2016-2017 Winter Rated Capacity

For the 2016-2017 winter season, MISO projected 140,774 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 2,255 MW of Behind-the-Meter Generation (BTMG) and 3,420 MW of Demand Resource (DR) programs, with 1,359 MW of Net Firm Exports. MISO expected 2,017 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 5,092 MW; thermal unit winter output reductions of 5,143 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 13,419 MW based on available nameplate wind resources of 16,041 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 876 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

Winter Reserve Margin Scenarios

MISO's projected 2016-2017 MISO Winter Rated Capacity varies by scenario (Figures 6.3-2 through 6.3-6). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 111,273 MW for the 2016-2017 winter.

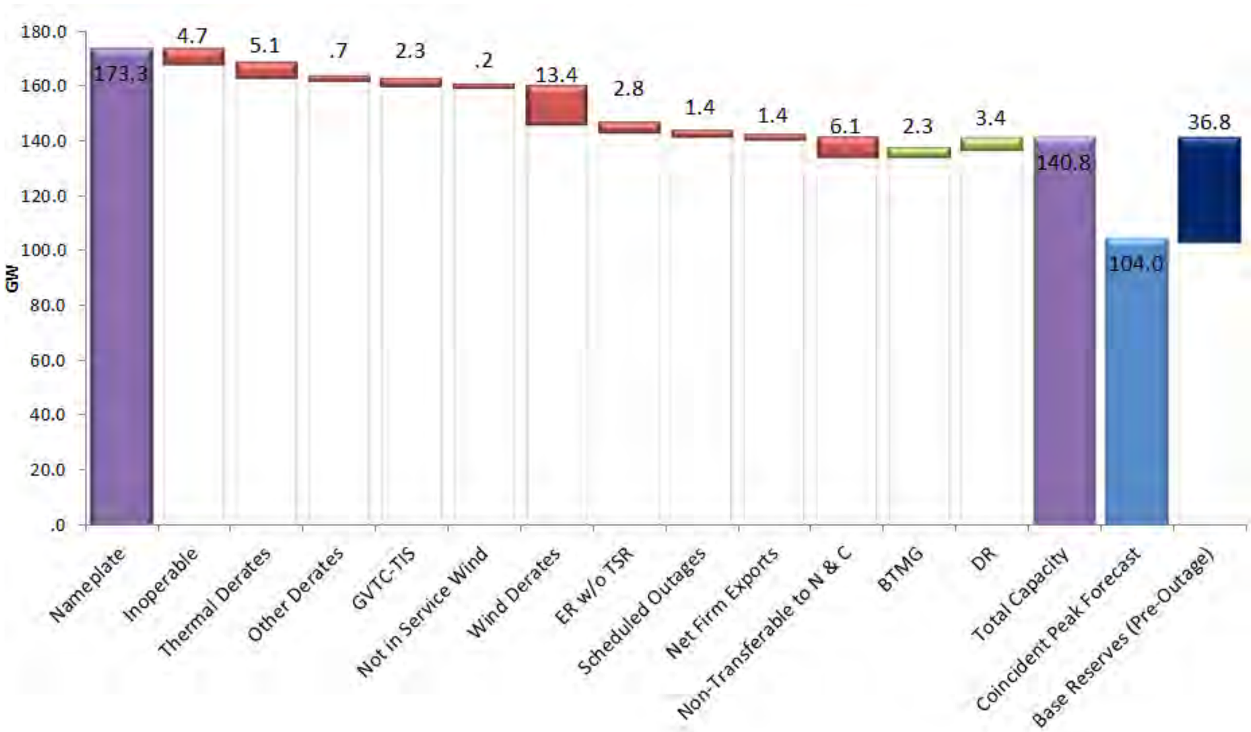


Figure 6.3-2: 2016-2017 Winter Rated Capacity projected Base scenario (GW)

The anticipated scenario contains additional assumptions (Figure 6.3-3). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 876 MW contract path limitation for the 2016-17 Planning Year.

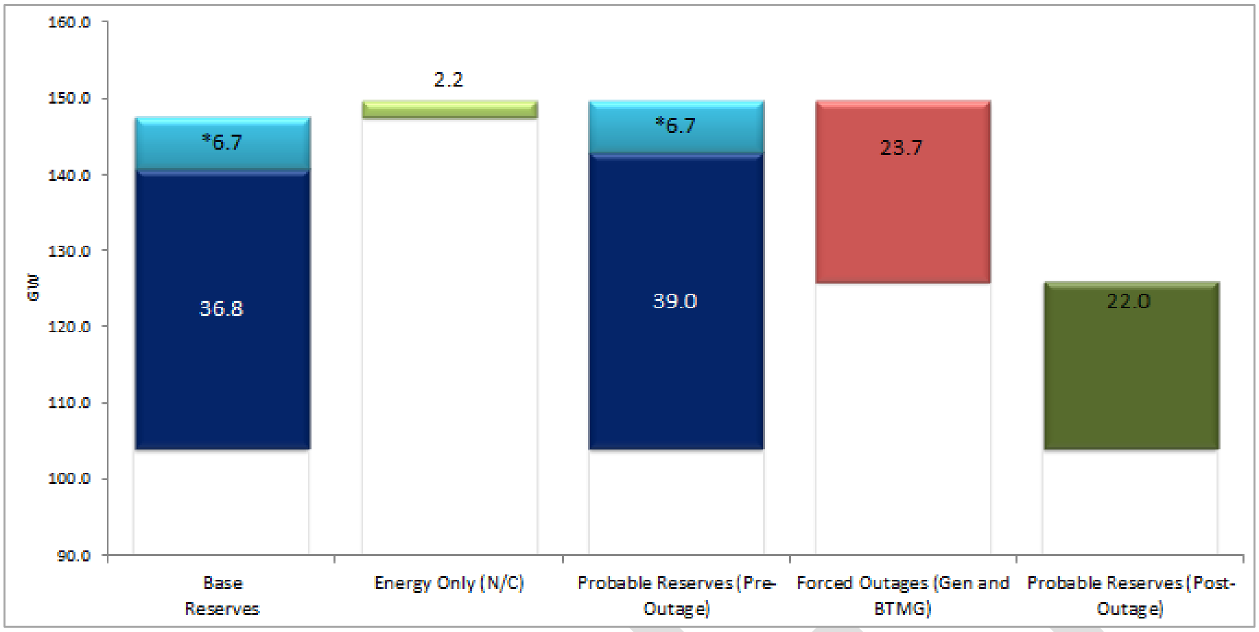


Figure 6.3-3: 2016-2017 Winter Rated Capacity projected Anticipated scenario (GW)
*Stranded South capacity is added to reserves to reflect outages seen by operations

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2016-2017 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

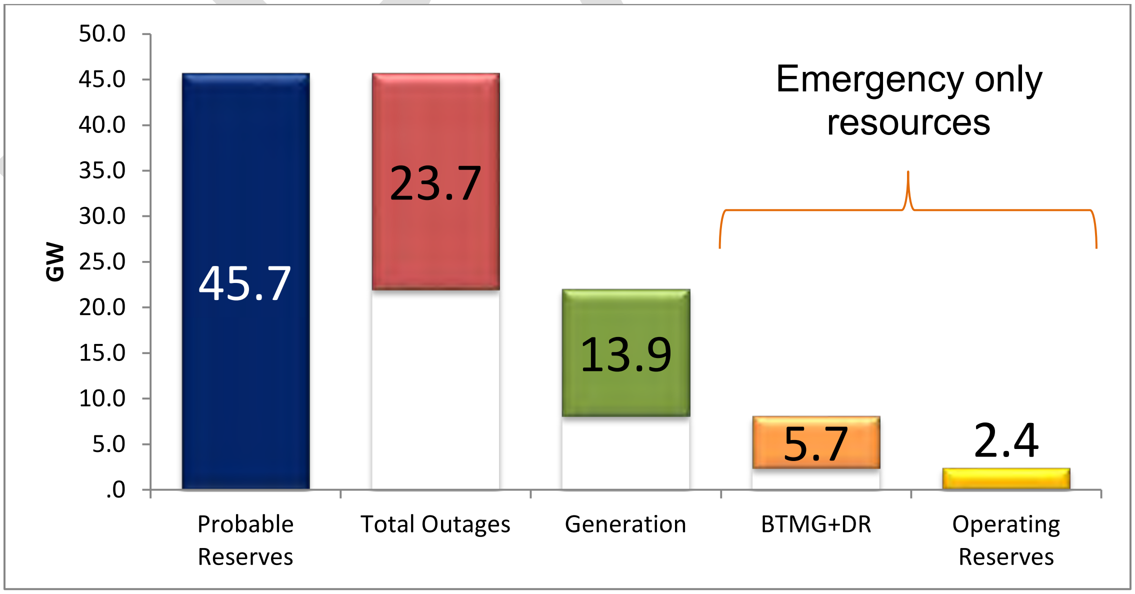


Figure 6.3-4: 2015-2016 Winter Rated Capacity projected anticipated scenario reserves (GW). Trapped South capacity is included in the probable reserves.

The High Demand, High Outage scenario has added assumptions (Figure 6.3-5). Beginning with the anticipated reserves from the Probable scenario (Figure 6.3-3), the load increases to show the higher load from a 90/10 forecast. Higher than normal outages are assumed reflecting the highest seasonal average outages reported in GADS from 2011-2015. The extreme outages reflect the highest number of GADS reported outages seen on winter peak from 2011-2015.

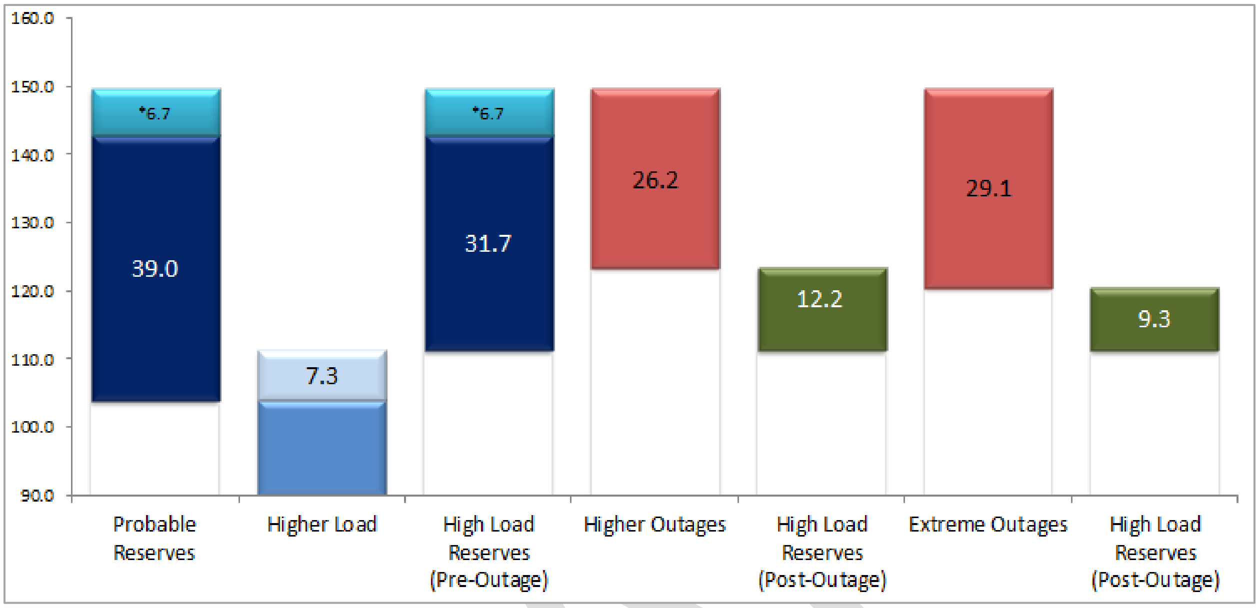


Figure 6.3-5: Winter Rated Capacity projected High-Demand, High-Outage scenario (GW)
*Stranded South capacity is added to reserves to reflect outages seen by operations

2017 Summer Overview

For planning year 2017-2018, MISO's PRM is 15.8 percent. During the 2017 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 18.8 percent, which exceeds the requirement of 15.8 percent by 3.0 percentage points. The summer scenarios project the reserve margin to be in the range of 14.1 to 19.7 percent (Figure 6.3-7).

MISO's 50/50 coincident peak demand for the 2017 summer season was forecasted to be 125,002 MW including transmission losses, with 148,465 MW of capacity to serve MISO load. Excluded from the capacity are 1,134 MW of MISO South resources to align with the 1,500 MW intra-RTO contract path.

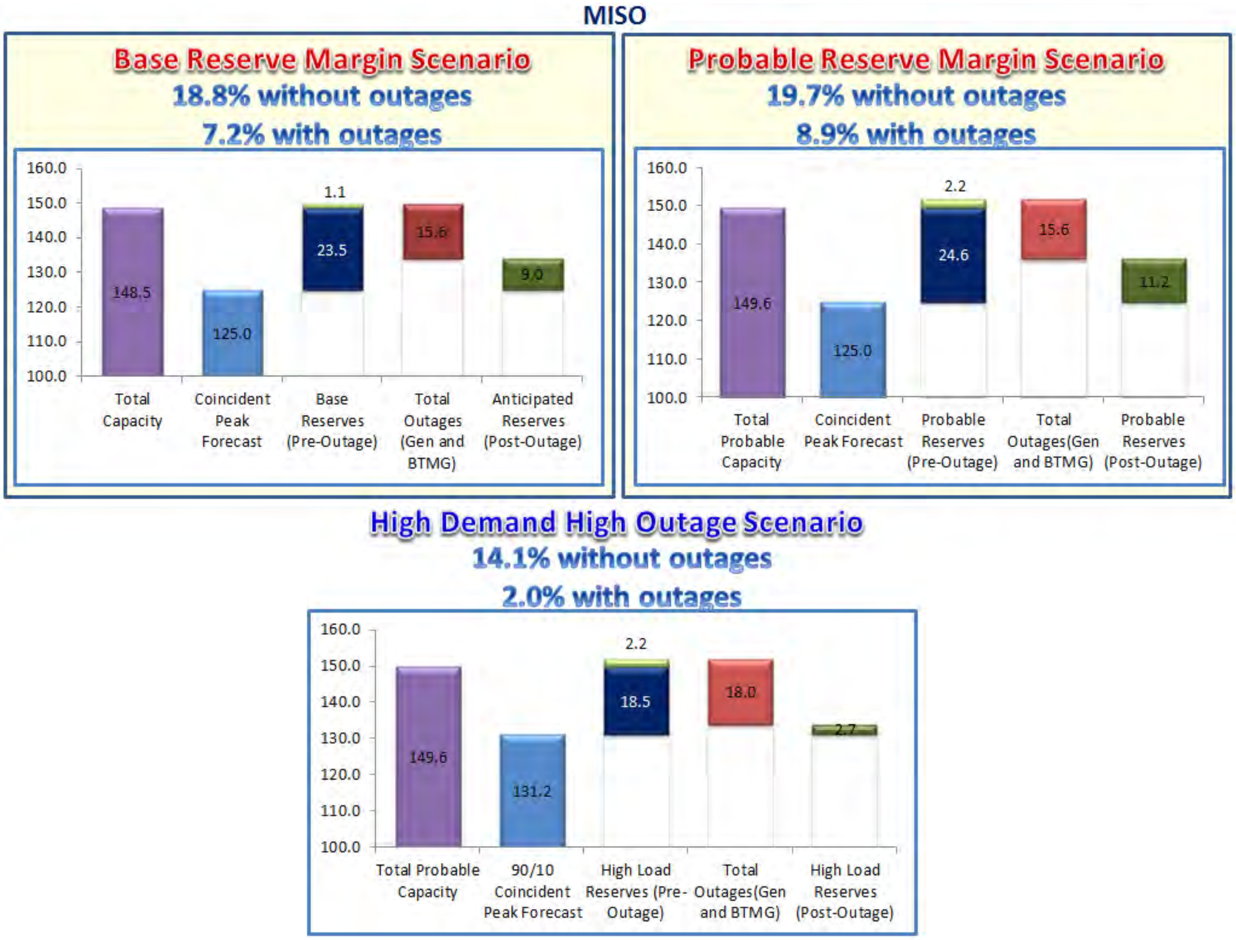


Figure 6.3-6: Summer 2017 Projected Reserve Margin scenarios

2017 Summer Rated Capacity

For 2017, MISO projected 148,465 MW of capacity to serve MISO load during the 2017 summer season. The capacity includes 4,059 MW of BTMG and 6,112 MW of DR programs, while including 45 MW of Net Firm Exports. MISO expected 2,281 MW of wind capacity to be available to serve load this summer, after discounting wind capacity in the Commercial Model with pending interconnection agreements and capacity with Energy Resource Interconnection Service without a firm point-to-point Transmission Service Request. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, 1,500 MW of excess capacity was assumed as transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (903 MW); thermal unit summer output reductions (9,601 MW); and reductions due to the Effective Load Carrying Capability of wind resources (13,241 MW). Also, any MISO South capacity over the total of South Load, South reserve margin requirement, and 1,500 MW of contract path was not included in the regional value. This means that 1,134 MW of MISO South excess capacity was excluded from the calculation to align with 1,500 MW contract path limitation.

Reserve Margin Scenarios

MISO's projected 2017 MISO Summer Rated Capacity varies by scenario (Figures 6.3-7 through 6.3-9). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 131,151 MW for the 2017 summer.

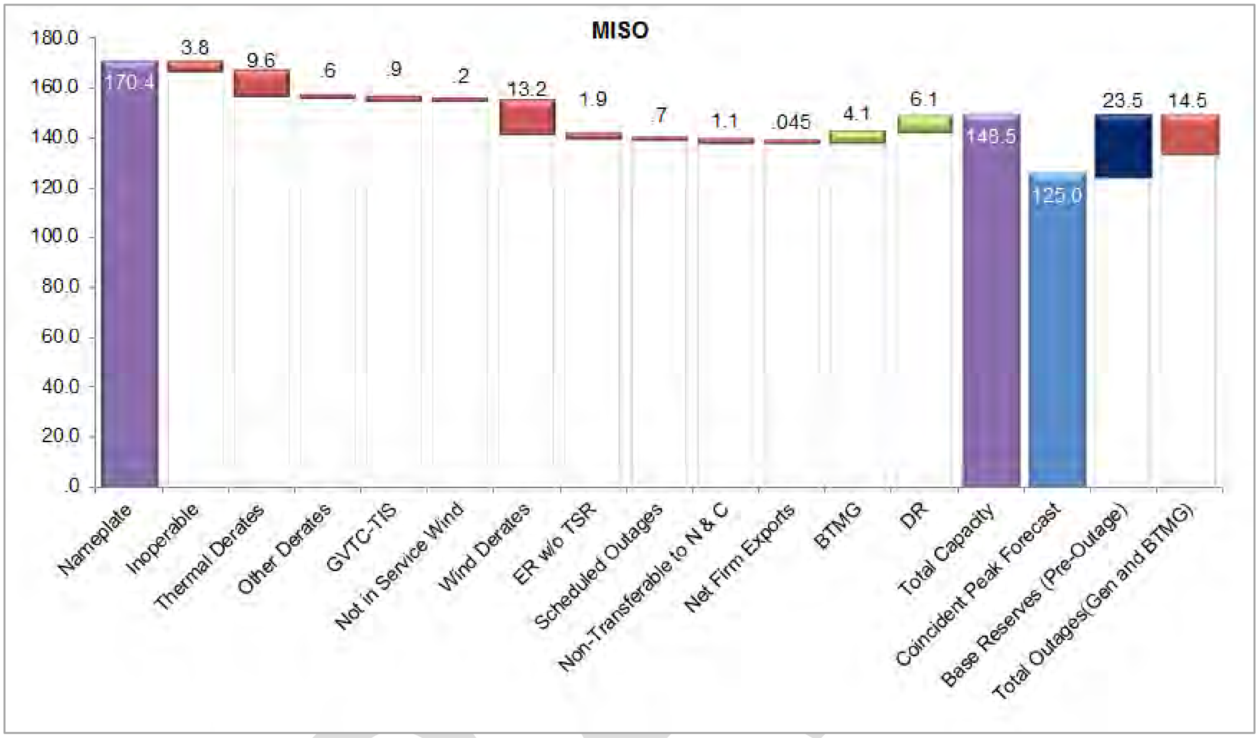


Figure 6.3-7: 2017 Summer Rated Capacity projected Base scenario (GW) showing the reduction from Installed Nameplate Resource Capacity. This includes derates and transmission limited resources.

The Probable scenario uses additional assumptions (Figure 6.3-8). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 1,500 MW contract path limitation. Additionally, any units designated as Under Study through the Attachment Y process are considered available.

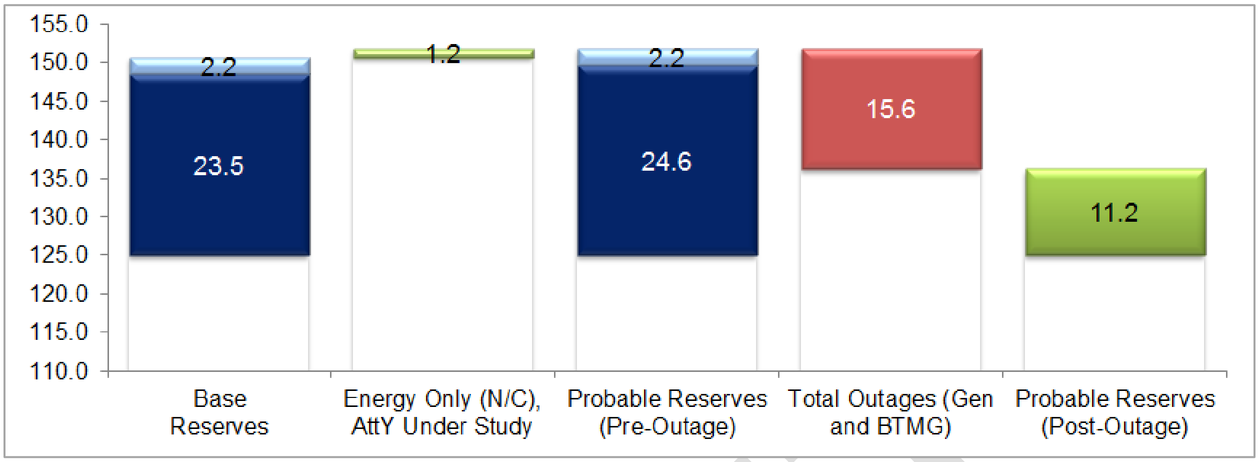


Figure 6.3-8: 2017 Summer Rated Capacity projected Probable scenario (GW), showing added capacity assumptions

The High Demand, High Outage scenario has added assumptions (Figure 6.3-9). Beginning with the Probable Reserves from the Probable Scenario (Figure 6.3-8), the load is increased to show the higher load from a 90/10 forecast. Also a higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available.

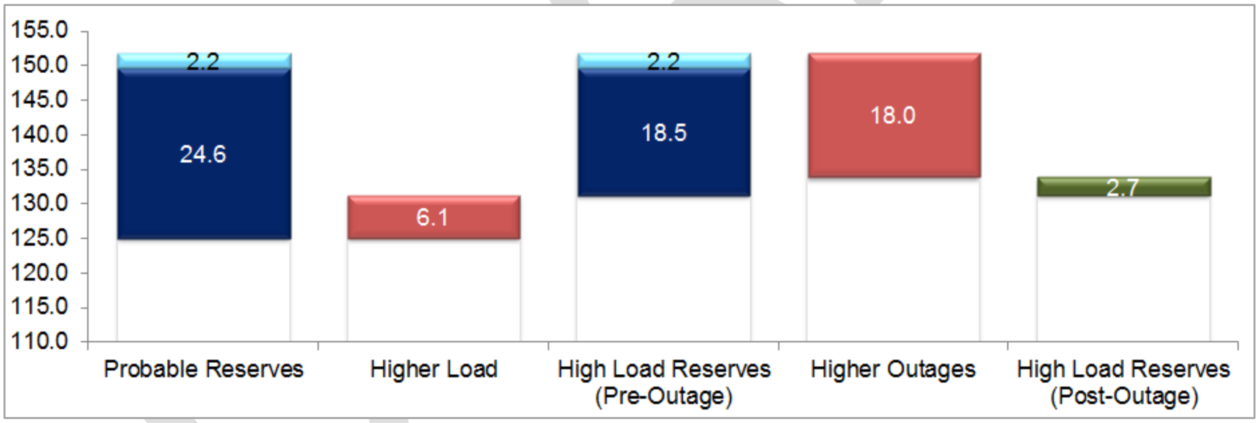


Figure 6.3-9: Summer Rated Capacity projected High Demand, High Outage scenario (GW)

2017 Summer Risk Assessment

MISO performs a probabilistic assessment on the region to determine the percent chance of utilizing Load Modifying Resources and Operating Reserves or having to curtail firm load. A risk profile is generated from this analysis (Figure 6.3-10).

It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, low water levels and other factors to lead to the curtailment of firm load. The Loss of Load Expectation (LOLE) model that MISO utilizes for PRMR takes into account the uncertainties associated with load forecasts (e.g., 50/50 versus 90/10) and generation outages (both forced and scheduled).

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.3-10). As shown, the probabilistic analysis indicated a 79.3 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 12.0 percent chance of initiating further steps to access Operating Reserves; and a 5.0 percent chance of curtailing firm load during the 2017 summer peak hour.

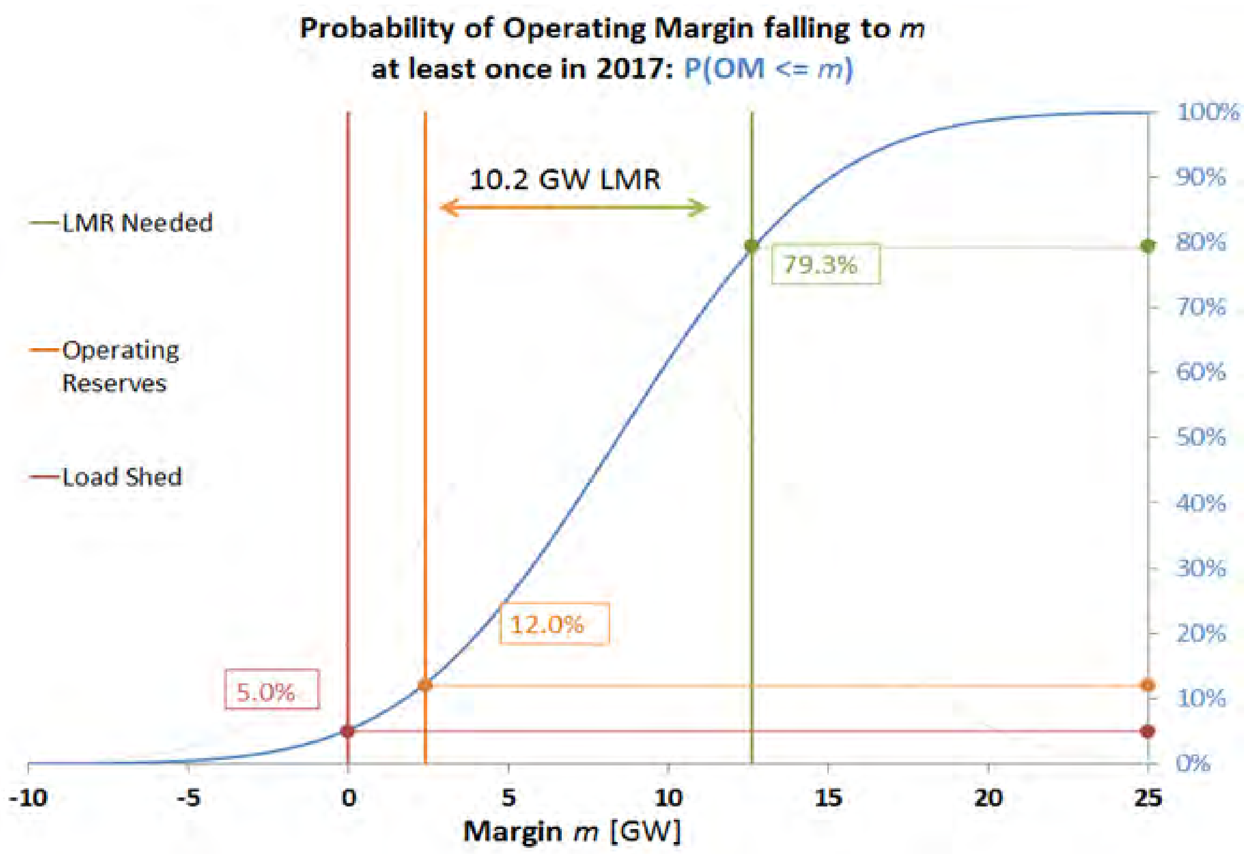


Figure 6.3-10: MISO 2016 summer chance of initiating Maximum Generation Emergency Step 2b or higher at forecasted Probable Reserve Margin

The reserves available in the Probable scenario are shown after forced, planned and maintenance outages are applied, showing the amount of Generation, BTMG, DR and Operating Reserves expected (Figure 6.3-11). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2017 summer season was 2,400 MW, which is called on as a last resort before load shed. Operating reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

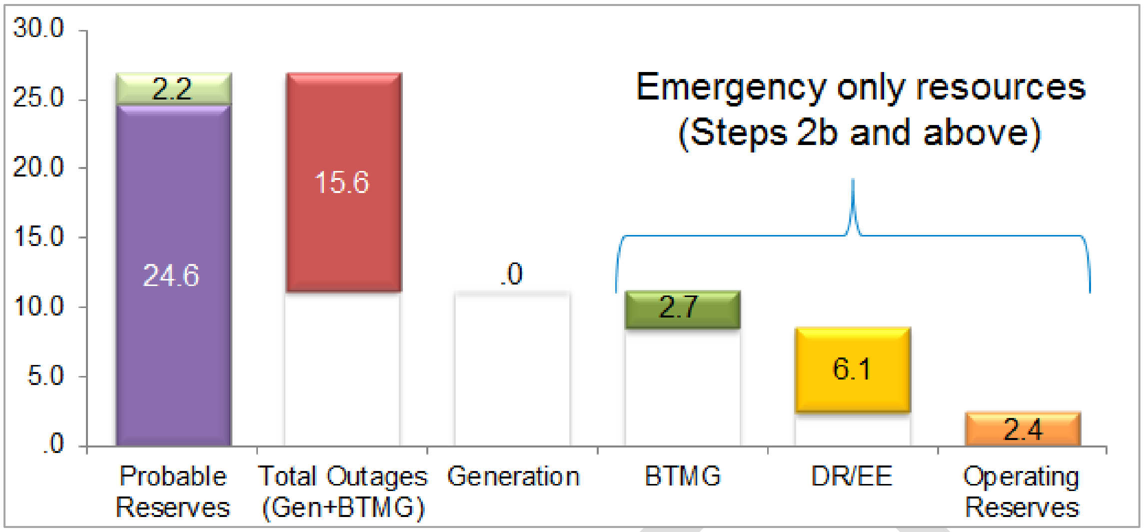


Figure 6.3-11: Summer Rated Capacity projected Probable Reserves (GW)

MISO Summer Rated Capacity Methodology

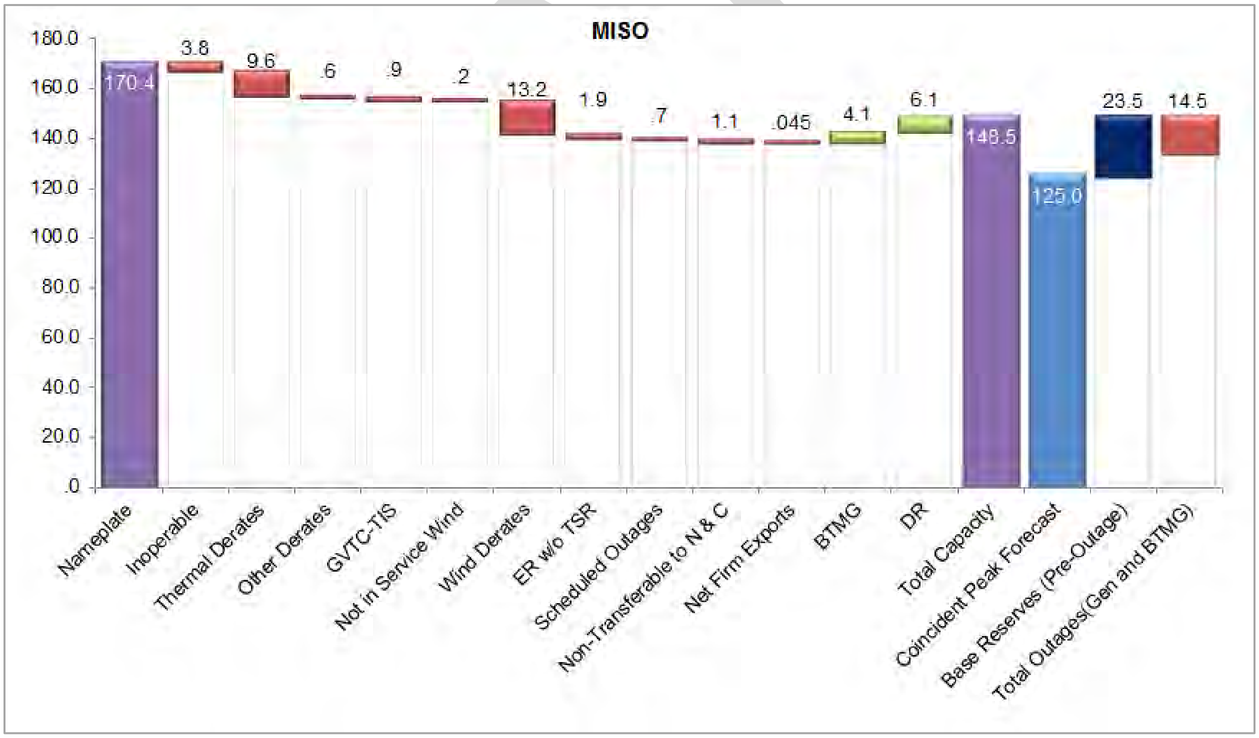


Figure 6.3-12: MISO 2017 Summer Rated Capacity waterfall chart, Base scenario (GW)

The calculation of MISO Summer Rated Capacity resources separates into 13 parts (Figure 6.3-12). Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2016-2017 Winter Resource Assessment. The 13 parts include:

1. *Nameplate*: the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable:* the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal Derates:* the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *Other Derates*: the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources (GVTC-TIS)*: the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind are the summation of differences in nameplate capacity and TIS.
6. *Not-in-Service and provisional wind*: units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind Derates*: the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *ER without TSR Energy-only:* resources with Energy Resource Interconnection Service (ERIS) without a firm point-to-point Transmission Service Right.
9. *Scheduled Outages*: Scheduled generator outages from June 1, 2017, through August 31, 2017, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler in March 2017. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."

   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.

   This calculation amounts to an expected scheduled maintenance of 696 MW.
10. *Net Firm Exports:* MISO anticipated the net firm interchange to be exporting 45 MW for the 2017 summer.
11. *Non-Transferable to MISO North and Central*: 1,134 MW of MISO South resources were excluded from the available capacity to align with 1,500 MW intra-RTO contract path.
12. *Behind-the-Meter Generation (BTMG)*: the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2017-2018 Planning Resource Auction, 4,059 MW of BTMG cleared to be available for the 2017 summer season.
13. *Demand Resource*: MISO currently separates contractual demand resource into two separate categories: Direct Control Load Management (DCLM) and Interruptible Load (IL).

    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.

    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 6,112 MW for the 2017 summer season.

6.4 Demand Response, Energy Efficiency and Distributed Generation

Although the same Applied Energy Group (AEG) forecast is used in MTEP16 and MTEP17, this section has been modified from the MTEP16 report to reflect changes for MTEP17 futures. The futures developed for MTEP17 are Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT). Each future uses a different AEG scenario provided in the forecast.

AEG developed a 20-year forecast of existing, planned and technical potential demand response (DR), energy efficiency (EE) and distributed generation (DG) programs and the associated costs in MISO and the Eastern Interconnection regions modeled in economic planning. This study, which was used in MTEP17, was completed in February 2016.

AEG received utility program data through a survey they conducted. Survey responses accounted for 93 percent of the load in 2016, and that data was supplemented with information from Energy Information Administration (EIA) Form 861.

In MTEP17, the Policy Regulations future uses the Existing Programs Plus scenario, which modeled existing 2016 program data from the utility survey and assumed a small annual increase in participation in programs through 2036 (0.5 percent increase each year; maximum 10 percent over 20 years). Peak demand and annual energy savings are broken down by Local Resource Zone (LRZ) and different cases are analyzed in the full report[7]. Summary results for the Existing Programs Plus cases are:

- Peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. Peak demand savings increase to 15 percent of the baseline summer demand by 2036.
    - On the residential side, appliance incentives, customer solar PV and customer wind turbines are the programs with the greatest estimated impact by 2026
    - On the commercial and industrial side, custom incentives, prescriptive rebates and customer wind turbines are the programs with the greatest estimated impact by 2026
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 7 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.
    - On the residential side, appliance incentives, customer wind turbines and whole-home audits are the programs with the greatest estimated impact by 2026
    - On the commercial and industrial side, custom incentives, prescriptive rebates, and retro commissioning are the programs with the greatest estimated impact by 2026
    - DG was considered a negligible percentage of these estimates with only a 0.6 percent cumulative effect by 2036

At the scoping phase of MTEP16 the Clean Power Plan (CPP) was in its draft form, which included energy efficiency as a building block. A specific scenario was created for the CPP initiative called 111(d). In the 111(d) case, to meet the compliance targets, AEG assumed utilities would see significant peak

7 AEG Report: https://www.misoenergy.org/Events/Pages/DREEDG20160208.aspx

demand savings starting with a slight ramp-up in 2018 to reach the EE goals in 2020[8]. Although the case specifically focuses on EE, AEG anticipated modest savings from demand response programs, as well. Savings are broken down by LRZ and different cases are analyzed in the full report. The 111(d) scenario was used for the AAT future in MTEP17, which was modeled to exceed the CPP carbon reduction target. Summary results for the 111(d) cases are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. However, peak demand savings increased to 27 percent of the baseline summer demand by 2036, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 16 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.

The MTEP17 Existing Fleet future used the Low-Demand scenario due to the low demand and energy growth rate modeled in this future. The summary results for the Low-Demand cases are:

- Peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. Peak demand savings increase to 13 percent of the baseline summer demand by 2036.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 6 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.

MTEP17 Futures	AEG Scenarios	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
		2016	2017	2018	2026	2036	2016	2017	2018	2026	2036
	Baseline Projection	118,235	119,349	120,058	126,174	136,441	678,651	685,467	690,015	732,076	801,747
PR	Existing Programs Plus Case Savings	6,326	6,900	7,466	12,481	20,263	3,221	5,326	7,447	25,314	53,225
	Existing Programs Plus Case Savings %	5%	6%	6%	10%	15%	0%	1%	1%	3%	7%
AAT	CPP 111(d) Savings	6,326	6,900	7,466	19,408	36,495	3,221	5,326	7,447	54,458	124,709
	CPP 111(d) Savings %	5%	6%	6%	15%	27%	0%	1%	1%	7%	16%
EF	Low Demand Savings	6,326	6,882	7,405	11,466	17,259	3,221	5,309	7,375	23,406	46,119
	Low Demand Savings %	5%	6%	6%	9%	13%	0%	1%	1%	3%	6%

Table 6.4-1: MTEP17 Futures Demand and Energy Savings

[8] AEG assumed additional programs will be added in order to help meet the compliance goals in the following manner: for existing programs, AEG assumed a higher participation rate as a result of presumed increase in marketing and awareness, and for programs not currently offered in the LRZ, AEG assumed that the program comes online in 2018 at a low participation rate.

The values shown in Table 6.4-1 are the same values used in MTEP16 and show technical potential of the scenarios. Specific programs modeled in the MTEP17 futures are those economically selected in the resource forecasting process.

This DR, EE and DG forecast allows MISO to analyze the impacts from these programs for transmission planning, real-time operations, and market operations (including resource adequacy). This forecast positions MISO to understand emerging technologies and the role they will play in transmission planning. Finally, the AEG forecast was incorporated into the gross Independent Load Forecast to create a net forecast. This process can be seen in Section 6.5: Independent Load Forecasting, Figure 6.5-4.

6.5 Independent Load Forecasting

The State Utility Forecasting Group (SUFG) created three 10-year horizon Independent Load Forecasts (ILF) for MISO. All three were submitted and delivered to MISO in November, the first ILF was submitted in 2014, second in 2015, and the third in 2016.

Additionally SUFG normalized historical data to create 50/50 historical data. Both Module E and ILF base are 50/50 forecasts, and this offers a more accurate comparison than with actuals. MISO wants to eliminate as much uncertainty as possible in long-term load forecasts; this is why MISO investigated ILF for any potential benefits in long-term planning. Through the three iterations and SUFG's work with MISO and stakeholders, MISO has found that ILF can consistently account for Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG) in long-term load forecasts. ILF offers a range by providing high, low and base forecasts.

The ILF is not intended to replicate or replace LSE or TO forecast processes or Module E; it is a complement long-term planning forecast to Module E. Long-term forecasts are becoming more critical due to fleet changes, renewable energy and emerging technologies such as behind-the-meter solar photovoltaic (PV), electric vehicles and energy storage. MISO will continue to use Module E for next-planning-year resource adequacy and capacity auction regardless of ILF findings.

Weather Normalized Historical

The ILF base and Module E are 50/50 forecasts. This means 50 percent of the time the load is higher than forecasted and 50 percent of the time it is lower. To offer a more direct comparison between these forecasts and actual historical data, SUFG weather-normalized actuals to create 50/50 weather normalized data for both energy and demand (Table 6.5-1 and Figure 6.5-1)[9]. This process involves electricity sales in specific areas, it involves MISO's current footprint including MISO South.

Year	2010	2011	2012	2013	2014	2015	2016
Actual	121,388	127,556	126,590	122,445	114,709	119,609	120,364
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952

Table 6.5-1: Coincident MISO peak weather normalized Historical vs. Actuals

[9] Complete weather normalized data is in the Independent Load Forecast report at https://www.misoenergy.org/Planning/Pages/IndependentLoadForecasts.aspx

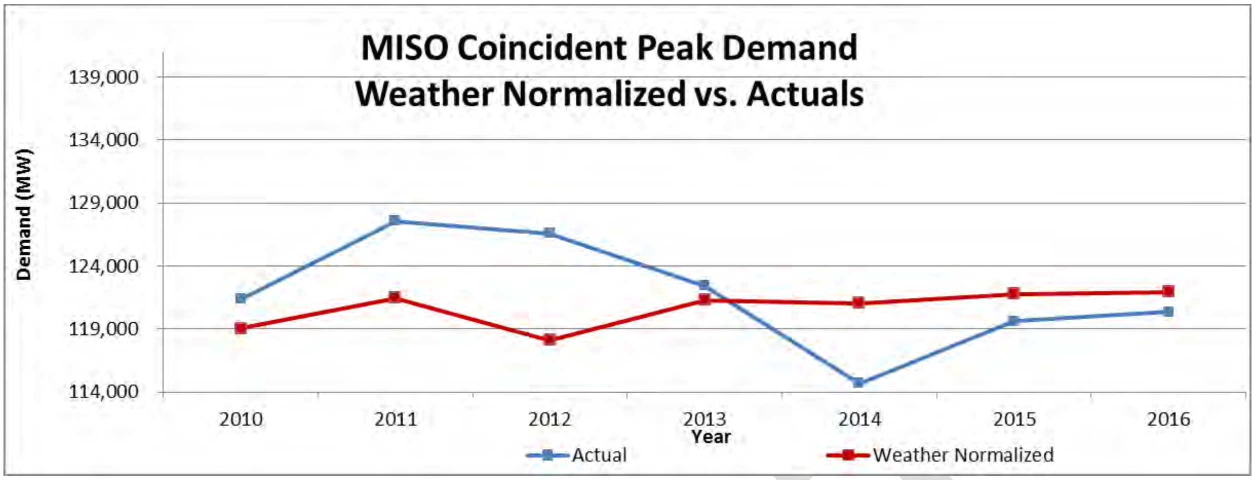


Figure 6.5-1: Coincident MISO peak weather normalized Historical vs. Actuals

Module E only provides coincident peak demand for the first year. A compound annual growth rate was found for Module E to be 0.3 percent. This growth rate was used to calculate the coincident peak demand for years 2018-2026, which contains transmission losses. This forecast is compared with the weather normalized data from SUFG because both are 50/50 values (Table 6.5-2 and Figure 6.5-2).

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952										
2017 Module E								125,002	125,377	125,754	126,131	126,509	126,889	127,269	127,651	128,034	128,418

Table 6.5-2: Coincident MISO peak weather normalized Historical vs. 2017 Module E forecast

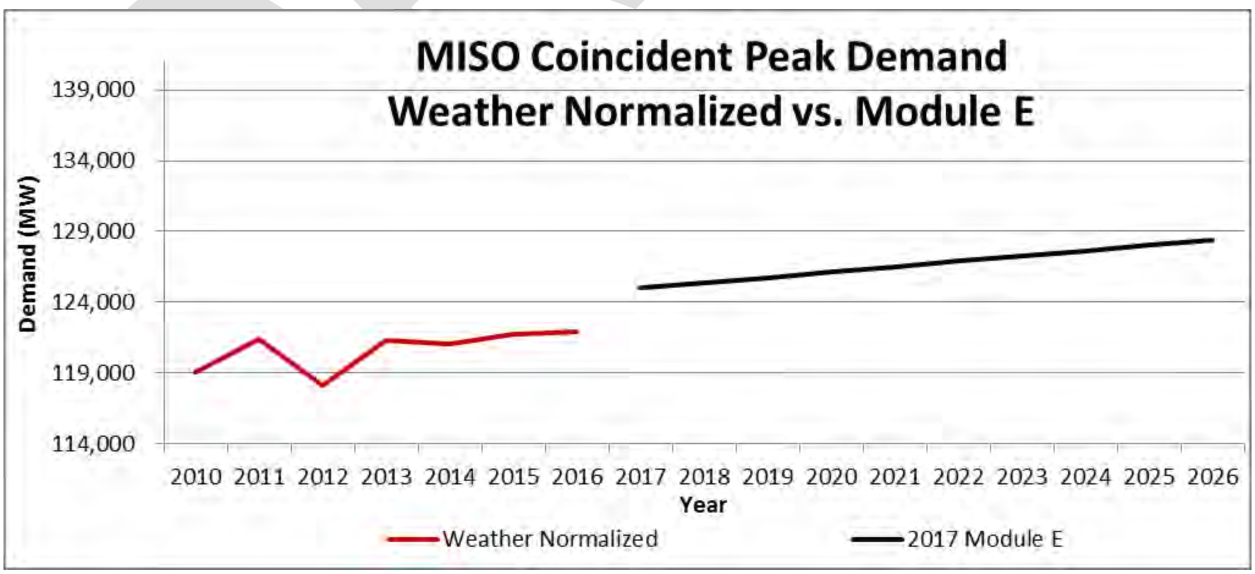


Figure 6.5-2: Coincident MISO peak weather normalized Historical vs. 2017 Module E forecast

The ILF base is also a 50/50 forecast, the gross values do not account for any EE/DR/DG whereas the net values do. The ILF forecasts were also compared to the weather normalized values (Table 6.5-3 and Figure 6.5-3).

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952										
2016 ILF Gross								125,801	128,001	129,836	131,438	132,768	134,224	135,756	137,414	138,983	140,610
2016 ILF Net								119,554	121,449	122,972	124,252	125,243	126,376	127,580	128,902	130,130	131,407

Table 6.5-3: Coincident MISO peak weather normalized Historical vs. 2016 Base ILF forecast

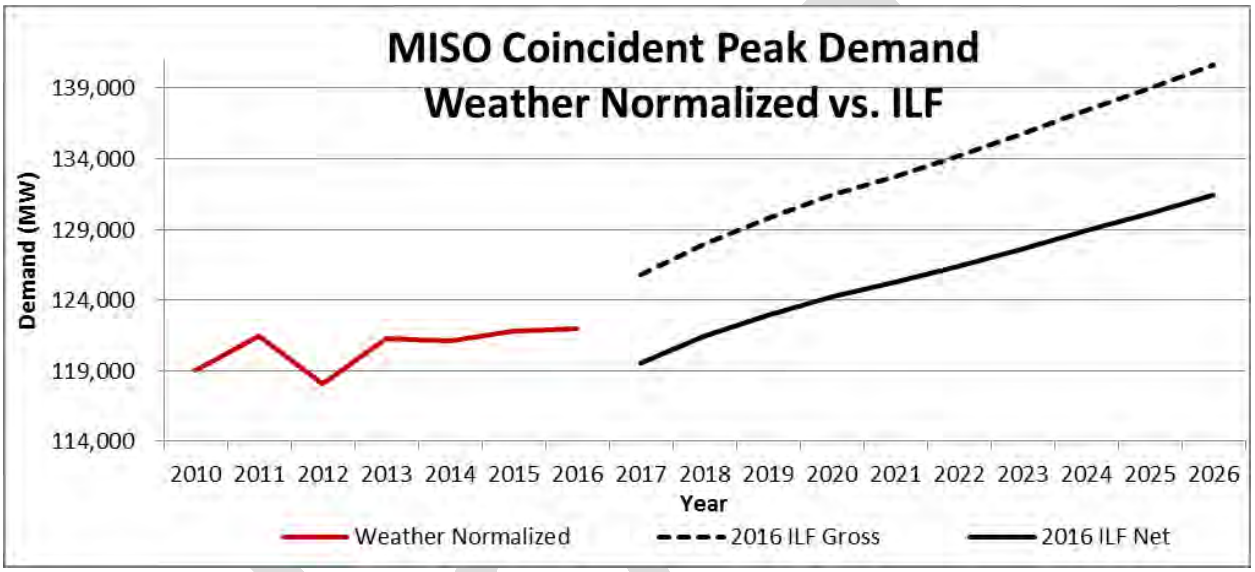


Figure 6.5-3: Coincident MISO peak weather normalized Historical vs. 2016 Base ILF forecast

Independent Load Forecast Process

MISO contracted with the SUFG from Purdue University as an independent vendor in 2014 to develop the ILF. SUFG produced econometric models for all 15 MISO states. The ILF uses public data from the Energy Information Administration to construct the forecasts. The ILF includes three main components for summer and winter seasons: annual energy for each of the 10 Local Resource Zones (LRZ) and MISO aggregate; coincident MISO peak demand (CP); and non-coincident peak demand (NCP), also known as zonal coincident peaks, for each of the 10 LRZs.

The ILF first provides un-adjusted forecasts that do not account for any EE, DR and DG existing or planned. This forecast is accompanied with the forecasts created by the Applied Energy Group (AEG) and then gets processed through EGEAS to develop net forecasts (Figure 6.5-4). A detailed description on how AEG programs are incorporated in MTEP Futures is discussed in detail in Section 5.2 MTEP Futures Development.

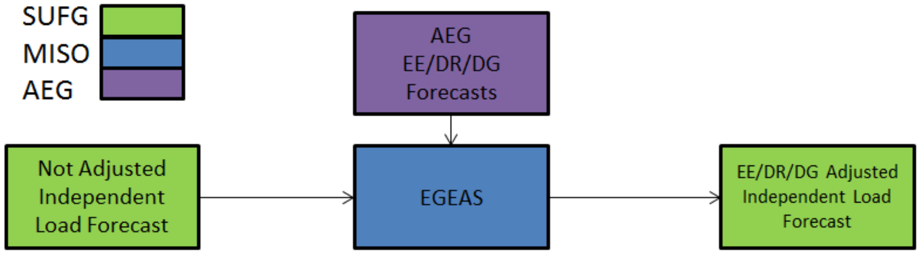


Figure 6.5-4: ILF Gross to Net Process
(gross has no EE/DR/DG adjustments; net has EE/DR/DG adjustments)

The ILF incorporates weather variables in its models and assumes normal weather conditions during the forecast period. The ILF base is a 50/50 forecast. The ILF also provides high and low forecasts, which allows for a range where the actual load might fall. The weather data used in the last two iterations was taken from a population-weighted average of multiple weather stations that represent the geographic areas in the specific state (Figure 6.5-5).

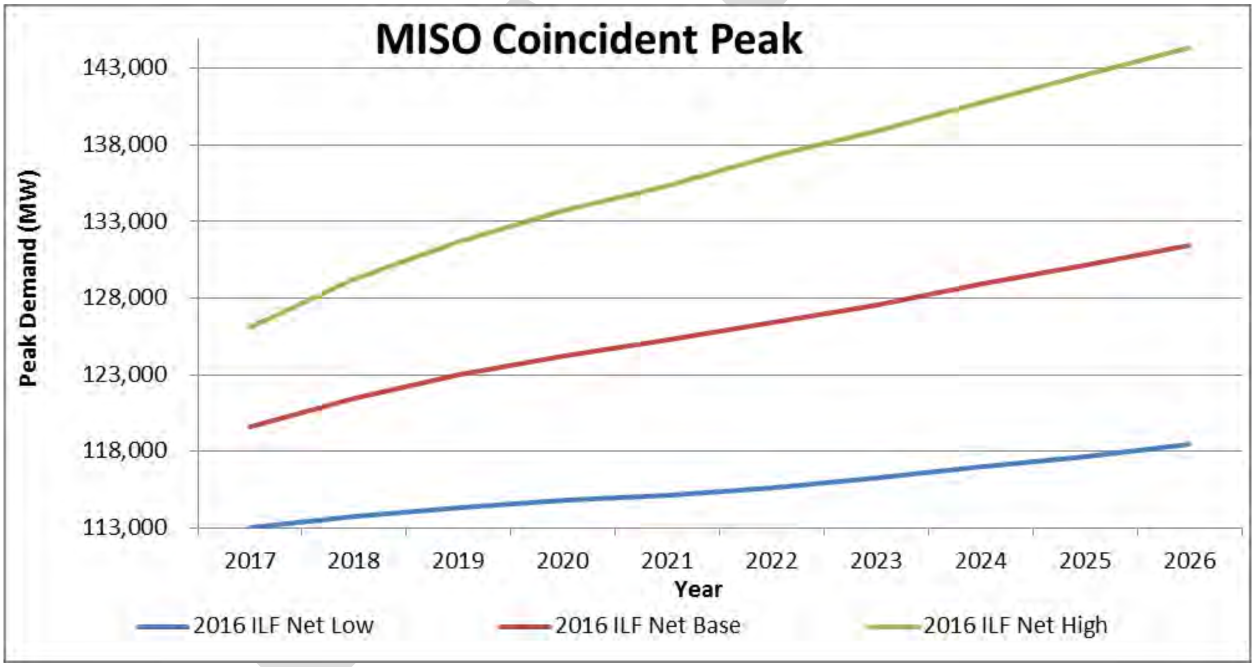


Figure 6.5-5: 2016 ILF Net Base vs. High vs. Low

What MISO Has Learned From the ILF

Through the three iterations of ILF, MISO has gained further insight and transparency into long-term load forecasts. Based on stakeholder feedback SUFG has refined its process and methodology. For example, in the 2014 ILF, SUFG created both gross and net predictions using states mandates and goals. In the 2015 and 2016 ILF, SUFG created a gross forecast and used AEG and EGEAS to create the net forecast. The difference in the Compound Annual Growth Rate (CAGR) between gross and net growth rates are significantly higher in year 1 (red) than in year 2 (blue) and year 3 (green) (Table 6.5-6).

	Year 1 (2015-2024)	Year 2 (2016-2025)	Year 3 (2017-2026)
Gross Energy	1.42	1.33	1.25
Net Energy	0.87	1.13	1.15
Gross Summer Peak	1.42	1.30	1.24
Net Summer Peak	0.86	0.96	1.06
Gross Winter Peak	1.41	1.32	1.25
Net Winter Peak	0.86	0.91	1.02

Table 6.5-6: ILF Compound Annual Growth Rates

AEG and EGEAS methodology align with MISO's current process and assumptions within MTEP. With the completion of the three ILF iterations, MISO believes it can gain valuable information from ILF and will continue to investigate how ILF may be able to assist MISO's long-term forecast (Figure 6.5-7). Long-term load forecasts are becoming more critical due to fleet changes, renewable energy, and emerging technologies like behind the meter solar PV, electric vehicles and energy storage. Proposed ILF inclusion in MTEP economic planning will be discussed with stakeholders in the Planning Advisory Committee meetings.

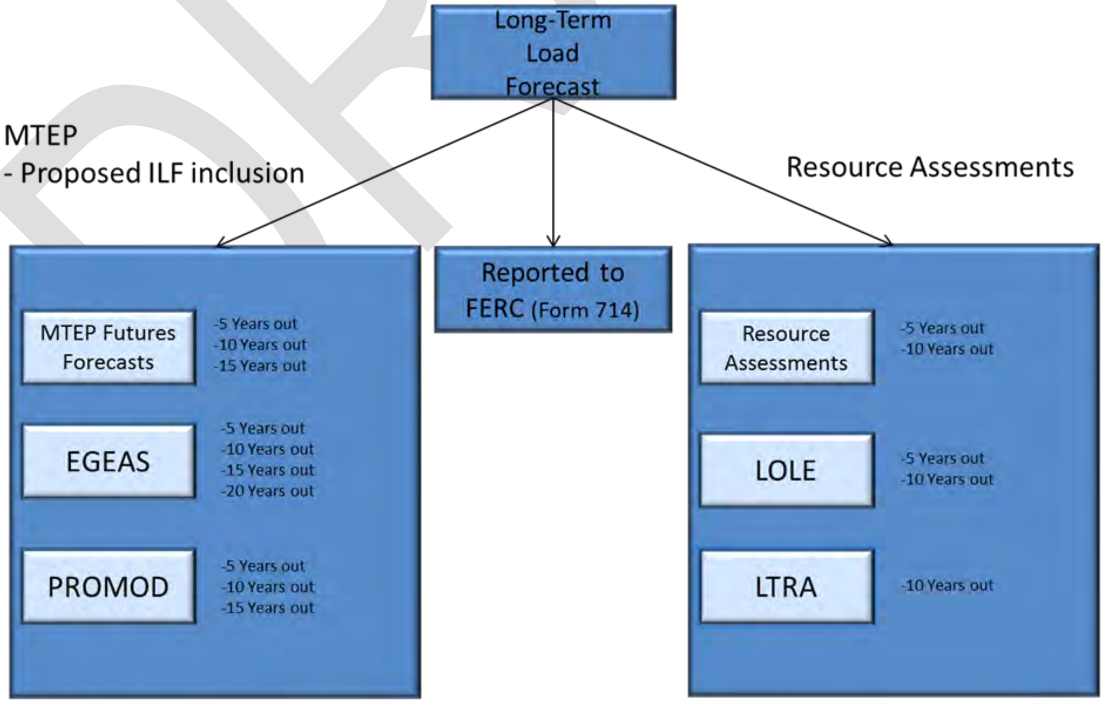


Figure 6.5-7: MISO's use of Long-term Forecasts

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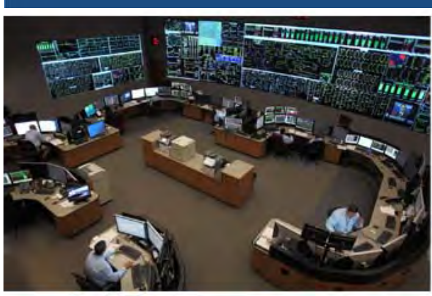
2016 Long-Term Reliability Assessment

December 2016

RELIABILITY | ACCOUNTABILITY

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

NERC Regions and Assessment Areas

FRCC–Florida Reliability Coordinating Council
- FRCC

MRO–Midwest Reliability Organization
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

NPCC–Northeast Power Coordinating Council
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

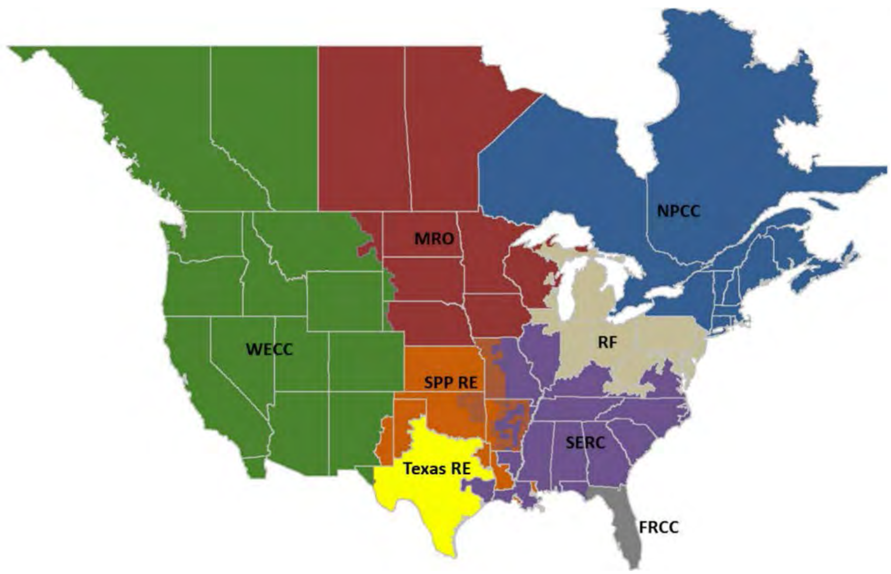
RF–ReliabilityFirst
- PJM

SERC–SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP RE–Southwest Power Pool Regional Entity
- SPP

Texas RE–Texas Reliability Entity
- Texas RE-ERCOT

WECC–Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US



Introduction

NERC prepares seasonal and long-term assessments to examine current and future adequacy and operational reliability of the North American BPS. For these assessments, the BPS is divided into 21 assessment areas[1] both within and across the eight Regional Entity boundaries as shown in the corresponding table and maps in the preface.[2] The preparation of these assessments involves NERC's collection and consolidation of data from the Regional Entities. Reference Case data includes projected on-peak demand and energy, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC Region are also collected and used to identify notable trends, emerging issues, and potential concerns (see Chapter 6). This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and the portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

NERC's primary objective with the *LTRA* is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years. NERC assesses this reliability by comparing projected reserve margins to Reference Margin Levels established by the assessment area or to a default Reference Margin Level. Reserve margins are typically developed using probabilistic methods that calculate the loss of load expectation (LOLE) that could occur less than or equal to one time in ten years based on daily peak information. Whereas these analyses typically evaluate resource adequacy in order to meet a peak day requirement. NERC recognizes that a changing resource mix with a significant portion of it being energy-limited, changes in off-peak demand, single points of disruption, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment and other ongoing analyses that provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes.

Additional issues that may potentially impact the reliability of the BPS, such as physical and cybersecurity, are not specifically reviewed by this assessment. These issues present constant and evolving challenges. NERC continues to lead a multi-faceted approach to enhancing cybersecurity, through mandatory standards, improved information-sharing through the Electricity-Information Sharing and Analysis Center (E-ISAC),[3] and exercises to increase learning about threats and vulnerabilities.

NERC has prepared the following assessment in accordance with the Energy Policy Act of 2005 in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the BPS in North America.[4] This assessment is based on data and information collected by NERC from the Regions on an assessment area basis as of September 2016. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the LTRA's development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS in open meetings. The review process ensures the accuracy and completeness of the data and information provided by each Region. This assessment has been reviewed and accepted by the PC. The NERC Board of Trustees also reviewed and approved this report.

[1] The number of assessment areas has remained the same since the release of the *2015 LTRA*. The previous MRO-MAPP footprint now resides in the SPP, MISO, and WECC-NWPP-US assessment areas. The previous WECC-CA has split into the WECC-BC and WECC-Alberta.
[2] Maps created using ABB Velocity Suite.
[3] NERC Electricity ISAC
[4] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the objectives, scope, data and information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

Executive Summary

The *2016 Long-Term Reliability Assessment* (*2016 LTRA*) provides a wide-area perspective of the generation, demand-side resources, and transmission system adequacy needed during the next decade. This assessment includes NERC's independent technical analysis to identify issues that may impact North American bulk power system (BPS) reliability, and this enables industry, regulators, and policy makers to develop mitigation plans or strategies to address them. NERC collected projections from system planners in each assessment area, assessed the data independently, and then identified emerging issues. These reliability issues require consideration to reduce BPS reliability risks and are summarized here in six focus areas:

- **Resource Adequacy:** Factors that are included when performing a resource adequacy assessment include a reserve margin analysis and the study of emerging reliability issues that can impact generation and demand projections. The results of this study identified four assessment areas as having a medium resource adequacy risk in the first five years of the assessment period:
    - **MISO:** The Anticipated Reserve Margin falls to 13.8 percent, below MISO's Reference Margin Level of 15.2 percent, in 2022. Due to the uncertain outcome of pending regulatory requirements in MISO's footprint, 3.3 GW of capacity are categorized as unconfirmed retirements. When applying these additional potential retirements, MISO's Anticipated Reserve Margin decreases to 14.9 percent in 2018, which is below the Reference Margin Level of 15.2 percent.
    - **NPCC-New England:** Reserve margins in NPCC-New England are projected above the Reference margin level for all years of the assessment. However, an increased reliance on natural gas, coupled with limited gas storage capability and dual-fuel switching challenges, indicate a medium resource adequacy risk, particularly during the winter peak season.
    - **Texas RE-ERCOT:** Anticipated Reserve Margins are projected to be sufficient for all ten years of the assessment period. Due to the uncertain outcome of pending regulatory requirements, approximately 7 GW of capacity are categorized as unconfirmed retirements. With considerations for unconfirmed retirements and assuming no potential replacement capacity, Texas RE-ERCOT's Anticipated Reserve Margin decreases to 11.3 percent by 2021, which is below the Reference Margin Level of 13.75 percent.
    - **WECC-CAMX:** Anticipated Reserve Margins are projected to be sufficient for all ten years of the assessment period. However, an increased reliance on natural gas, limited dual-fuel capability, and natural gas storage facility outages indicate a medium resource adequacy risk. Additional challenges are posed in maintaining adequate essential reliability services (ERSs), such as maintaining ramping capability.
- **Single-Fuel Dependency:** NERC has identified that reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions. Over the past decade, several areas have significantly increased their dependence on natural gas. This trend has continued amidst historically low natural gas prices and regulatory rulings that continue to promote increased natural gas generation. NERC's assessment identifies four assessment areas with high penetration of natural gas generation:
    - **Texas RE-ERCOT:** Natural-gas-fired generation comprises 63 percent of on-peak anticipated capacity by 2021. Gas-fired generators in ERCOT have some dual-fuel capability (14 percent). However, pipeline infrastructure in Texas is tightly meshed, and natural gas generators often have multiple connections and access to natural gas.
    - **FRCC:** Natural-gas-fired generation will comprise 69 percent of on-peak anticipated capacity by 2021. Natural gas is not widely used for residential heating; therefore, the pipeline system has largely been built to support its gas-fired generation customers. Gas-fired generation in Florida is largely fueled with firm transportation services that is approved by the public utility commission to ensure a reliable

source of fuel. Additionally, a majority of gas-fired generation is dual-fuel capable, and limited inventory is kept on-site for use in emergencies.

- **NPCC-New England:** Natural-gas-fired generation will comprise 52 percent of on-peak anticipated capacity by 2021. The risk in New England is increasing due to the limited addition of new interstate pipeline capacity and the fact that natural gas storage does not appear to keep pace with natural gas generation additions. Additionally, recent winter experiences have created challenges in both maintaining back-up fuel inventories and successfully switching from gas to oil. However, emerging market rules in ISO-NE, beginning in 2018, are expected to support reliability and the resilience of the generation fleet.
- **WECC-CAMX:** Natural-gas-fired generation comprises 68 percent of on-peak anticipated capacity by 2021. Minimal dual-fuel capable units and immediate resource constraints from the outage at the Aliso Canyon underground natural gas storage facility increase the risks associated with single-fuel dependency.

- **Nuclear Uncertainty:** Low natural gas prices continue to affect the competitiveness of nuclear generation and are a key contributing factor to nuclear generation's difficulty in remaining economic with competing fuel sources. While new nuclear facilities are being built in Georgia, Tennessee, and South Carolina, potential retirements have been announced for nuclear facilities in Illinois, California, Nebraska, Massachusetts, and New York, creating longer-term uncertainty for system operators and planners. While replacement capacity may be advanced to mitigate resource adequacy concerns, unconfirmed nuclear retirements create uncertainty around local transmission adequacy and the ability to plan for future resource and demand needs due to their large baseload contribution.
- **Probabilistic Analysis**: The changing resource mix introduces additional complexities to assessing resource adequacy and diminishes the value of a single deterministic planning metric (e.g., reserve margins). NERC's probabilistic assessment (see Chapter 2) provides key indices that, together, assess resource adequacy risks for all hours of the study year.
- **Essential Reliability Services:** The addition of a large number of variable energy resources (VERs) onto the BPS has resulted in the need for operational flexibility to accommodate demand while also effectively managing the resource portfolio. As VERs are becoming more significant, NERC is developing sufficiency guidelines in order to establish requisite levels of ERSs. ERSs are comprised of primary frequency response (PFR), voltage support, and ramping capability, all needed for the continued reliable operation of the BPS. Significant ramping capabilities are needed to address the challenges presented from VER operational impacts. Ramping issues requiring increased operational flexibility have been most notable in California, where they occurred four years earlier than originally projected. Texas RE-ERCOT is also beginning to project potential ramping issues, but current real-time market design, operating practices, and the flexibility of existing generation provide ERCOT with sufficient capability to manage ramping requirements.
- **Distributed Energy Resources:** Increasing installations of distributed energy resources (DERs) modify how distribution and transmission systems interact with each other. Many utilities currently lack sufficient visibility and operational control of these resources, increasing the risk to BPS reliability. This visibility is a crucial aspect of power system planning, forecasting, and modeling that requires adequate data and information exchanges across the transmission and distribution interface. The most significant growth in DER penetration is occurring in NPCC and WECC. NERC's Distributed Energy Resources Task Force will release their initial their report in Q1 of 2017. This report will review current impact to reliability and considerations for resource and transmission planning.

Recommendations

NERC has developed the following recommendations through its stakeholder process to alleviate the potential impacts of the reliability issues identified in this assessment:

- Regulators and legislators should evaluate the changes occurring on the BPS irrespective of the final rulings on pending regulation, such as the Clean Power Plan (CPP). While there is uncertainty around the ultimate validity and timing of the CPP, NERC has determined that many of the changes are occurring regardless of the final ruling. As the resource mix continues to change, the need for more investments in transmission and natural gas infrastructure is currently projected. The lengthy schedule involved in acquiring, siting, and permitting adequate properties for this infrastructure should also be considered when assessing reliability impacts. Policy makers should closely monitor and evaluate the measures being taken to address the evolving resource adequacy trends in MISO and Texas RE-ERCOT.
- As natural-gas-fired resources continue to increase, system planners and operators should evaluate the potential effects of an increased reliance on natural gas on BPS reliability. Natural gas provides “just-in time” fuel; therefore, firm transportation and maintaining dual-fuel capability can significantly reduce the risk of common-mode failure and wider-spread reliability challenges. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can affect electric reliability.
- Regulators and legislators should consider the uncertainties in resource retirements and resource mix changes projected by resource planners and the interconnection-wide impacts, including generation retirements, curtailments, and transmission constraints that can manifest if ERSs are not maintained. The implementation of a regulatory framework to provide an adequate level of ERSs could help to address these uncertainties. Planning Coordinators and Transmission Planners should consider supplementing planning processes with additional measures that support maintaining sufficient ERSs. In 2017, NERC will draft sufficiency guidelines for ERSs to support planning evaluations and assessments of how the resource mix can impact BPS reliability; NERC recommends incorporating sufficiency measures within planning processes.

Chapter 1: Reliability Issues

This section highlights several issues that are emerging and have the potential to increase risks to reliability. The *2016 LTRA* identifies these issues to include: resource adequacy, single-fuel dependency, nuclear uncertainty, essential reliability services (ERSs), and distributed energy resources (DERs).

Reserve Margins

General Assumptions: The reserve margin calculation is an important industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak demand (load) and projected availability of resources to serve the forecast peak demand for the summer and winter of the 10-year outlook (2017–26).

Demand Assumptions: Electricity demand projections, or load forecasts, are provided by each assessment area. Load forecasts include peak hourly load, or total internal demand, for the summer and winter of each year. Total internal demand projections are based on normal weather (50/50 distribution) and are provided on a coincident basis for most assessment areas. Net internal demand equals the total internal demand minus the controllable & dispatchable demand response (DR) considered available across the peak.

Resource Assumptions: NERC collects projections for the amount of existing and planned capacity as well as net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources

- **Existing-Certain generating capacity:** includes operable capacity expected to be available to serve load during the peak hour with firm transmission.
- **Tier 1 capacity additions:** includes capacity that has completed construction, is under construction, has a signed or approved ISA/PPA/CSA/WMPA, is included in an integrated resource plan, or is under a regulatory environment that mandates a resource adequacy requirement.
- **Firm Capacity Transfers (Imports minus Exports):** transfers with firm contracts

Prospective Resources: Includes all anticipated resources, plus:

- **Existing-Other capacity:** includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable for a number of reasons.
- **Tier 2 capacity additions:** includes capacity that has been requested but that has not received approval for planning requirements.
- **Expected (non-firm) Capacity Transfers (Imports minus Exports): t**ransfers without firm contracts, but a high probability of future implementation.

Reserve Margins: the primary metric used to measure resource adequacy. It is defined as the difference in resources (anticipated, or prospective) and net internal demand divided by net internal demand, shown as a percent.

$$\textbf{Anticipated Reserve Margin} = \frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

$$\textbf{Prospective Reserve Margin} = \frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

Reference Margin Level: The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISOs/RTOs, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.

Resource Adequacy

The Anticipated Reserve Margin is the primary metric that is used to evaluate the adequacy of projected resources to serve forecasted peak load. **Figure 1.1** provides an examination of the Anticipated Reserve Margin and how to interpret the results of the analysis. Having a shortfall of reserves indicates that an assessment area would fall below their target Reference Margin Level, and increases the risk to reliability by increasing the likelihood of a potential loss of load.

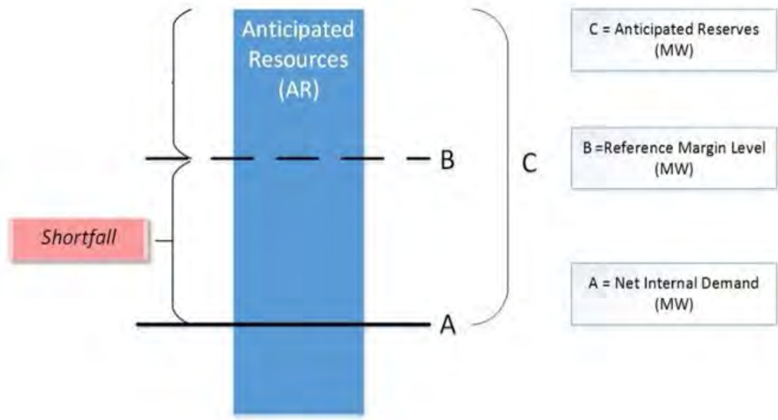


Figure 1.1: Examination of Anticipated Reserve Margin

Based on the data and information provided to NERC, all assessment areas Anticipated Reserve Margins that meet or exceed their Reference Margin Levels. While three areas fall below their respective Reference Margin Levels in the 6- to 10-year time frame, there are measures that can be taken to address potential shortfalls. Examples include advancing designated planned resources within the generation queue, securing neighboring capacity through transmission expansions, and firm transmission contracts. Generally, shortfalls identified in the latter years of the assessment period pose a less significant risk to resource adequacy due to more time and available mitigation options. Alternatively, an assessment area with additional planning reserves may not maintain the requisite level of ERSs, thereby introducing complexity into an assessment of resources to consider other measures of sufficiency in addition to reserve margins.[5]

Figure 1.2 and **Figure 1.3** show the five- and ten-year planning reserve margins respectively. All assessment areas meet or exceed their Anticipated Reserve Margins through the first five years of the assessment while three assessment areas Anticipated Reserve Margins do fall under their designated Reference Margin Level by year ten.

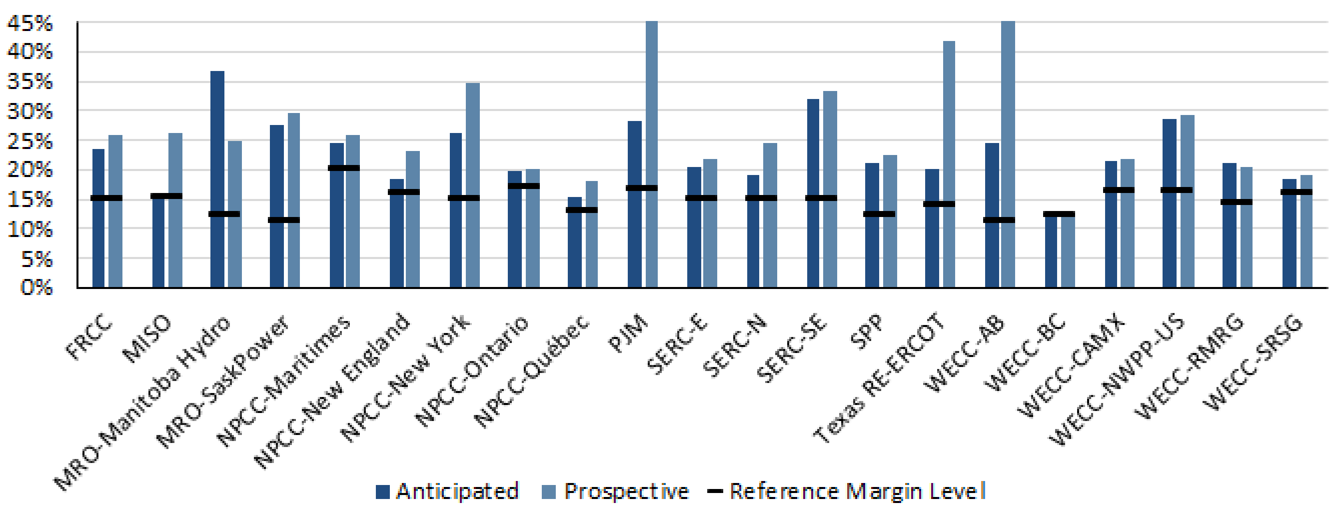


Figure 1.2: Planning Reserve Margins for Year 5 (2021)

[5] Requisite levels of ERSs will be determined by the Sufficiency Guidelines currently under development with the NERC Essential Reliability Services Working Group

MISO is currently projected to fall below their target of 15.20 percent to an Anticipated Reserve Margin of 13.89 percent in 2022 and continue to decrease to 9.07 percent by the year 2026. NPCC-Québec is currently projected to fall below their target of 12.70 percent to 12.28 percent in 2025 followed by a decrease to 11.59 percent by 2026. WECC-BC is currently projected to fall below their target of 12.10 percent to 11.60 percent in 2025 followed by a decrease to 9.79 percent by 2026.

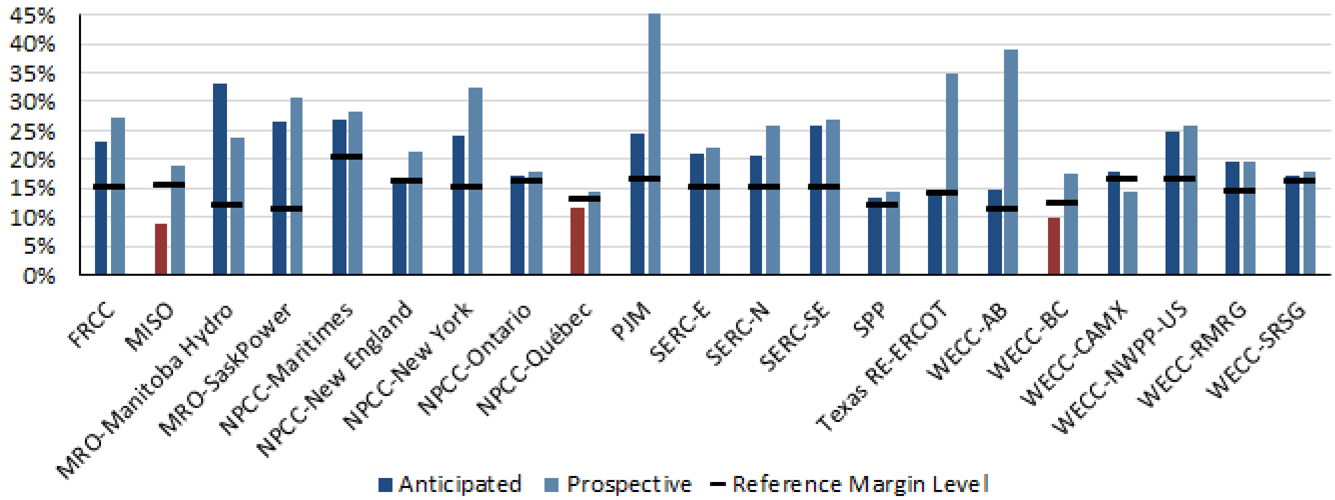


Figure 1.3: Planning Reserve Margins for Year 10 (2026)

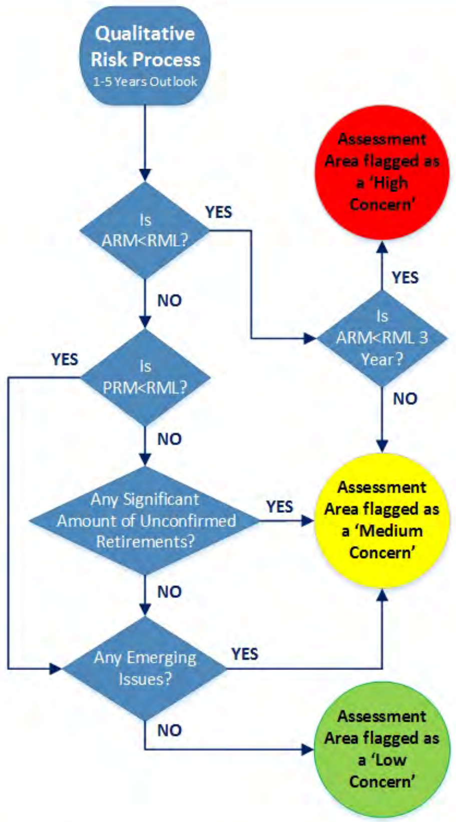
Figure 1.4 below contains a qualitative risk process flowchart for the short-term (1-to-5 years) outlook and a chart showing the corresponding resource adequacy risk of a capacity shortage by assessment area. The 6-to-10 year outlook flowchart is a direct extension of the 1-to-5 year. The flowchart outcomes for this qualitative analysis result in flagging an assessment area as: 1) a high concern (shown by a red circle indicator), 2) a medium concern (shown by a yellow circle indicator), or 3) a low concern (shown by a green circle indicator).

For example: an area is flagged as high concern when a Region's Anticipated Reserve Margin (ARM) is less than the Reference Margin Level (RML) in both the 1-to-5 year outlook and the 1-to-3 year time frame. When one or a combination of factors contribute to risk, the area is flagged as a medium concern. The factors that are considered are as follows: Prospective Reserve Margin (PRM), ARM, RML, unconfirmed retirements, and emerging and sustaining issues. Lastly, if an area is not flagged as high or medium, it is identified as having a low concern with respect to near- and long-term resource adequacy risk.

Confirmed and Unconfirmed Retirements

NERC collects two separate line items for retirements in the development of the *Long-Term Reliability Assessment*:

- Units whose retirements are designated as "confirmed" have formally announced plans to retire and these units must have an approved generator deactivation request where applicable. These units are individually identified within the data collection.
- "Unconfirmed" retirements are collected but aggregated by fuel type. These include units that have been earmarked for retirement but have not met the same requirements as those given as confirmed. These include units that are expected to retire based on the result of a generator survey or assessment area resource adequacy study.



Perceived Resource Adequacy Risk by Assessment Area (Low, Medium, or High Concern)		
Regions	**1 to 5 Years: Risk**	**6 to 10 Years: Risk**
FRCC	🟢	🟢
MISO	🟡	🟡
MRO-Manitoba Hydro	🟢	🟢
MRO-SaskPower	🟢	🟢
NPCC-Maritimes	🟢	🟢
NPCC-New England	🟡	🟡
NPCC-New York	🟢	🟢
NPCC-Ontario	🟢	🟢
NPCC-Québec	🟢	🟡
PJM	🟢	🟢
SERC-E	🟢	🟢
SERC-N	🟢	🟢
SERC-SE	🟢	🟢
SPP	🟢	🟢
Texas RE-ERCOT	🟡	🟡
WECC-AB	🟢	🟢
WECC-BC	🟢	🟡
WECC-CAMX	🟡	🟡
WECC-NEWPP-US	🟢	🟢
WECC-RMRG	🟢	🟢
WECC-SRSG	🟢	🟢

ARM: Anticipated Reserve Margin **PRM: Prospective Reserve Margin** **RML: Reference Margin Level**

Figure 1.4: Qualitative Risk Process Flowchart (left) and Corresponding Perceived Resource Adequacy Risk

Results of this qualitative risk analysis indicate that a total of four assessment areas have a medium reliability concern in the short-term and six assessment areas for the long-term. Assessment areas that indicated a medium risk in the short term are reviewed in more detail. These include:

- **MISO:** Lower Anticipated Reserve Margins and a significant amount of unconfirmed retirements due to the potential outcome of pending regulatory requirements indicate a medium resource adequacy risk.
- **NPCC-New England:** A growing reliance on natural gas, the lack of dual-fuel compatible units, and limited gas storage capability indicate a medium resource adequacy risk.
- **Texas RE-ERCOT:** Significant amounts of unconfirmed retirements due to the potential impacts of pending environmental regulations and a high reliance on natural-gas-fired generation indicate a medium resource adequacy risk.
- **WECC-CAMX:** A high reliance on natural gas, limited dual-fuel capability, and the potential reduction in adequate ERSs indicate a medium resource adequacy risk.

Recent environmental and other regulatory requirements have introduced greater uncertainty around the future of some resources. In addition to the other challenges brought forward by the incorporation of a changing resource mix, this increasing uncertainty of future resources is compounded by advanced retirements of conventional fossil-fired generating units and the capacity contributions expected from an increasing amount of variable generation. **Figure 1.5** shows the total amount of capacity retirements projected to occur in 2015 and 2016 using forecasted and actual data. The actual 2015 retirements totaled 24.3 GW, which was 3.3 GW more, or 15 percent, than the 21 GW forecasted by the *2015 LTRA*. Similarly, the *2015 LTRA* forecasted 9.3 GW of retirements to occur in 2016, but the *2016 LTRA* estimates an additional 3.4 GW, or 36 percent, more than the prior year's assessment.

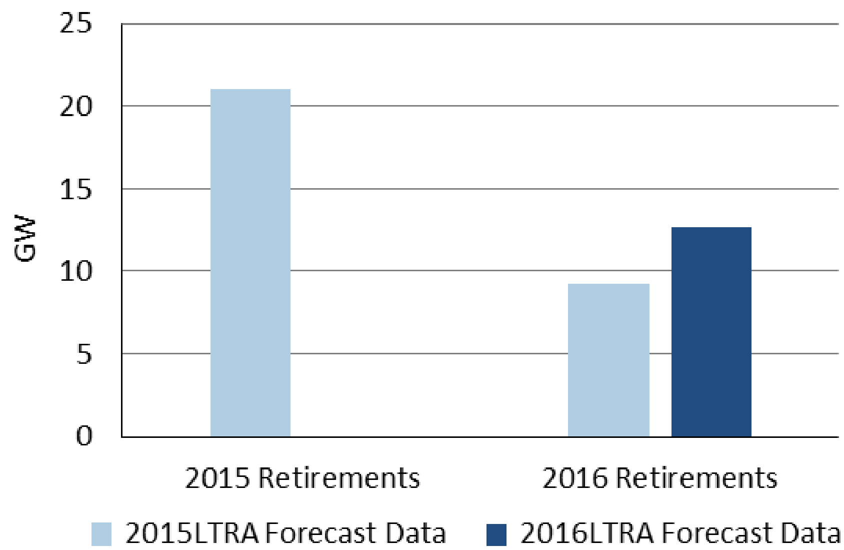
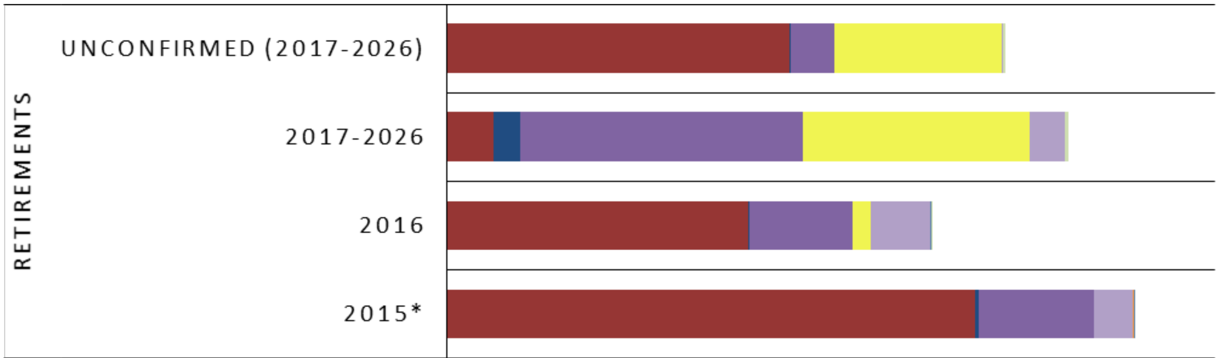


Figure 1.5: Total Projected Confirmed Retirements Increase between Assessment Years

As the outcome of retirement decisions are made public, upward adjustments on expected retirements continue to be incorporated into NERC's projections. Since 2012, approximately 40 GW of coal-fired and 30 GW of oil-fired generation have been retired in North America, roughly 7 percent of 2016 summer peak demand.

NERC examines both confirmed and unconfirmed generation retirements in the 10-year forecast. The Anticipated Reserve Margin includes only generation retirements that have been confirmed. However, given federal, state, and provincial policies, a number of power plants have an increased risk of retirement, and this should be considered when evaluating planning reserve margins. NERC's assessment found both the MISO and Texas RE-ERCOT assessment areas showing significant changes to their reserve margin forecasts when considering unconfirmed retirements and assuming no potential replacement capacity.

Figure 1.6 shows the total amount of actual nameplate capacity retirements from 2015 and the projected retirements for years 2016–2026 by fuel type. The data indicates there were significant coal retirements in 2015, greater than the total retirements projected for the ten-year assessment period.



	Retirements			
	2015*	2016	2017-2026	Unconfirmed (2017-2026)
Coal	13,747	7,850	1,195	8,927
Hydro	104	21	692	20
Natural Gas	3,001	2,680	7,395	1,148
Nuclear	-	502	5,901	4,374
Petroleum	1,013	1,548	929	6
Solar	44	1	-	-
Wind	36	3	-	-
Other	-	10	87	67

Figure 1.6: NERC-Wide MW Nameplate Capacity Retirements from 2015 to 2026 by Fuel Type
***Actual Data**[6]

NERC also conducted a sensitivity analysis in which no Tier 2 capacity was built and all unconfirmed retirements were taken out of service. The aggregated unconfirmed retirements were provided from MISO through the Organization of MISO States (OMS) survey results for 2016.[7] This provides insight on the potential retirement of many resources in the MISO footprint. The survey results provide a greater confidence factor to apply the unconfirmed retirements into a reserve margin sensitivity analysis. Similarly, ERCOT released their 2016 CDR, providing additional detail on power plant retirement risks and generation fleet changes.[8] While both MISO and ERCOT have sufficient Tier 2 resources in the queue, depending on the timing of the retirements (Tier 2 resources may not be available to advance their in-service dates), which could increase the risk of an electricity supply shortage.

MISO

Similar to the *2014 LTRA* and *2015 LTRA* reference cases, the *2016 LTRA* reference case projects a shortfall in MISO's Anticipated Reserve Margins during the assessment period. The shortfall in projections is due to generation retirements outpacing the addition of Tier 1 resources; there is sufficient Tier 2 and Tier 3 generation that could be advanced to mitigate these capacity concerns. MISO is projecting an Anticipated Reserve Margin of 13.8 percent for the 2022 summer peak, which continues to trend downward to 9.0 percent by the end of 2026. MISO will require approximately 8 GW of additional resources by the end of the 10-year forecast in order to maintain the Reference Margin requirements of 15.2 percent. Considerations should be given to the assessment area's need for sufficient ERSs. These may include generation additions that are mostly asynchronous and may offer a reduced level of voltage, frequency, and/or ramping support, depending on equipment characteristics and facility design. Shown in **Figure 1.7**, the Reference Margin requirements are up by 0.9 percent compared to the *2015 LTRA* reference case due to resource adequacy study assumptions. These changes are mostly due to the

[6] Actual data for 2015 collected from EIA Electric Power Monthly
[7] Organization of MISO States Survey Results; 2016
[8] Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2016-2025; May 2016

2014–2015 planning year being the first year of integrating the MISO South Zone with limited data being available.[9]

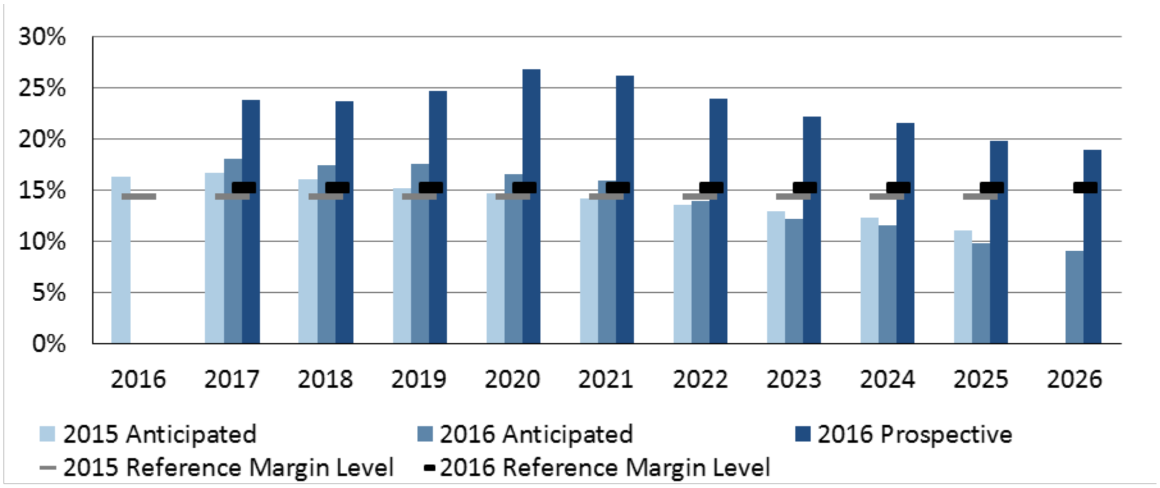


Figure 1.7: MISO 2015 LTRA and 2016 LTRA Reserve Margin Comparison

MISO gathered data for the past three years through the OMS Survey as part of their resource adequacy study. Survey results indicate that certain locations within the assessment area will have to rely on imports as early as 2017 from their neighboring zones, such as Missouri and Lower Michigan. The survey resulted in an estimation of 3.3 GW plant retirements by 2026. NERC considers these retirements as unconfirmed and are the major contributor in the advanced Reserve Margin shortfalls. ReliabilityFirst's *2016 Long-Term Resource Report* also identified these potential risks highlighted by the OMS survey results.[10]

Deliverability of New Resources

One of the major challenges in long-term system planning is the changing nature and location of available resources to load. The North American BPS does not provide infinite routes for all generation; therefore, the transition from a central-station model to a more dispersed BPS creates some challenges in power delivery and transmission. System planners use modeling software to simulate current and projected grid components and characteristics. From these models, transmission planners will identify potential future contingencies on lines and evaluate options, such as uprating or building new lines to mitigate contingencies before they occur. Having new resources built long distances from the load requires that new lines be built to effectively deliver this new generation to where it is needed. Transmission congested lines and operational challenges are likely to escalate within an area if the constraints are not alleviated.

Figure 1.8 includes the resulting unconfirmed retirement sensitivity analysis impacts on MISO's Anticipated Reserve Margins, which will fall below the Reference Margin Level by 2018. While the reference margin is not met in the five-year period given unconfirmed retirements, MISO appears to have sufficient Tier 2 resources to meet the Reference Margin Level. The long-term resource adequacy forecast is generally low risk, but as variable resources increase, Reference Margin Level requirements may increase beyond the current 15.2 percent in the future years.

[9] MISO Loss of Load Expectation Study Report: Planning year 2016-2017
[10] ReliabilityFirst 2016 Assessment-Long Term Resource; August 2016

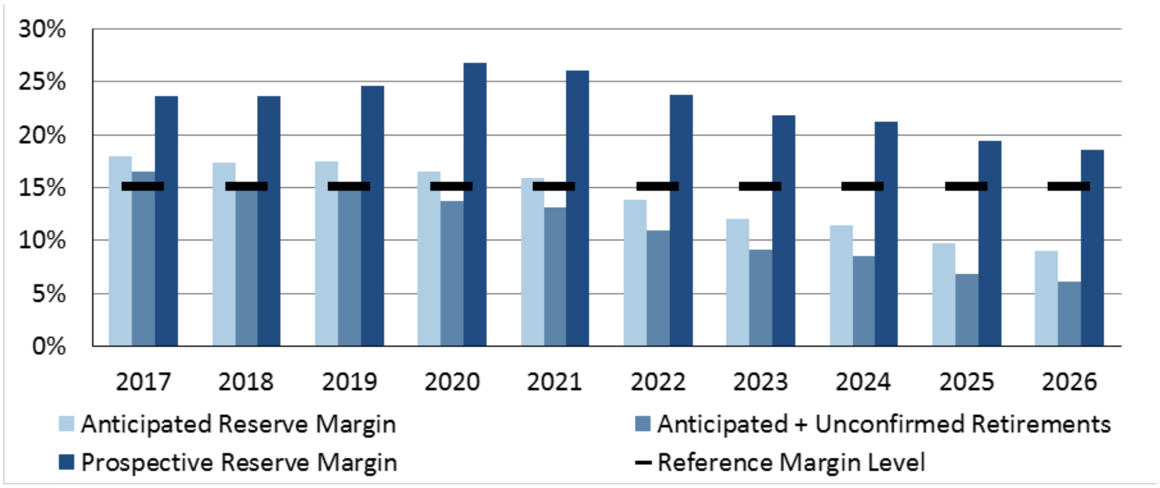


Figure 1.8: MISO Reserve Margins with Unconfirmed Retirements

MISO's long-term resource challenges are exacerbated by increasing transmission requirements. The MISO forecast includes a significant expansion of wind resources. Because of the geographic diversity of wind resources to load, more long-distance and networked transmission will be needed. Ensuring the deliverability of these resources is challenging when resources are located distant from the load. For example, forced curtailments of wind resources are sometimes required to prevent congestion on transmission lines. An August 2016 report by the U.S. Department of Energy[11] showed that the percentage of wind curtailment in MW to the total potential wind generation has increased in MISO from under 2 percent in 2007 to over 5.5 percent in 2015. An increase in wind curtailments could be a result of transmission inadequacy, minimum generation limits, other forms of grid inflexibility, and/or environmental restrictions. This could lead to an increased risk of real-time capacity deficiencies.[12]

NPCC-New England

The Anticipated Reserve Margins for NPCC-New England, shown below in **Figure 1.9**, exceed the Reference Margin Level for all years of the assessment period. Compared to the *2015 LTRA* reserve margin analysis, the Anticipated Reserve Margins have increased by 0.5 percent in 2017 and by 3.32 percent by year 2025. The majority of this change is due to a slight reduction in the ten-year peak load forecast.

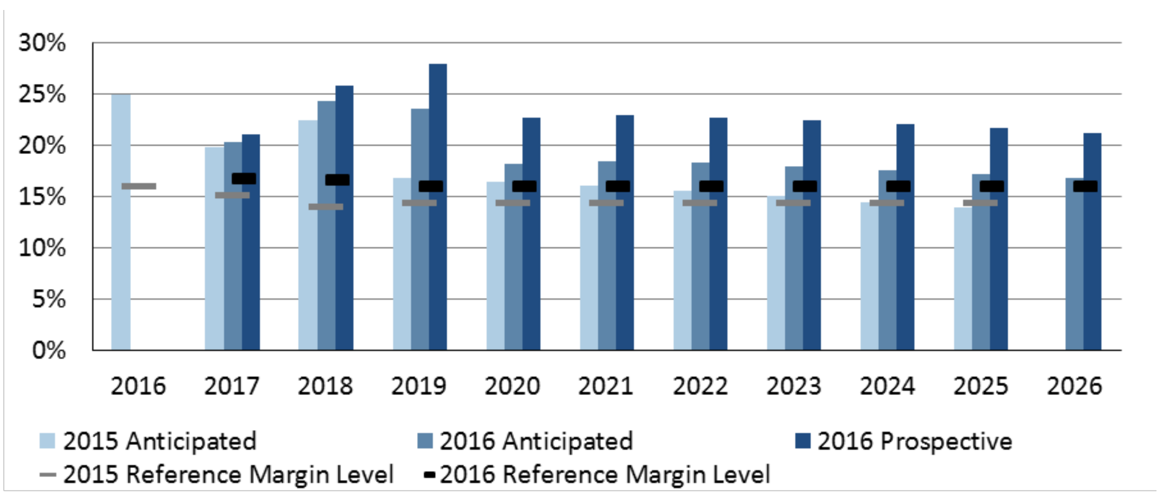


Figure 1.9: NPCC-New England 2015 LTRA and 2016 LTRA Reserve Margin Comparison

[11] Department of Energy: Wind Technologies Market Report - August 2016

[12] *Ibid*.

The results from the qualitative risk analysis, as presented in the Qualitative Risk Process flowchart (**Figure 1.4**), highlighted NPCC-New England as having a perceived medium resource adequacy risk. While the results of the reserve margin analysis indicate that NPCC-New England has sufficient capacity to remain above their Reference Margin Level, there are other standing or emerging issues that must be considered when performing a more holistic overview of the assessment area's potential risks to reliability.

NPCC-New England faces additional challenges due to a high dependency on natural gas, a reduced dual-fuel capable fleet, and limited storage capability. These challenges are exacerbated by high winter gas demand competitiveness from customers other than electric generating facilities and inadequate natural gas pipeline infrastructure.[13]

Texas RE-ERCOT

NERC's *2015 LTRA* reference case showed Texas RE-ERCOT projections below the Reference Margin level of 13.75 percent to 13 percent by 2022, and continuing to decline to 9.4 percent by 2025. Comparing last year's data in **Figure 1.10**, the *2016 LTRA* reference case indicates that ERCOT is now not projected to fall below its Reference Margin Level within the ten-year assessment. This is due to a decrease in net internal demand forecasted in future years and an increase in planned capacity. Comparing forecasted peak load by the year 2025, ERCOT is showing a decrease of 1.2 GW, or a 1.5 percent reduction, from last year's assessment. Similarly, ERCOT is showing an increase in their anticipated resources by 3.8 GW or 4.6 percent increase when compared to last year.

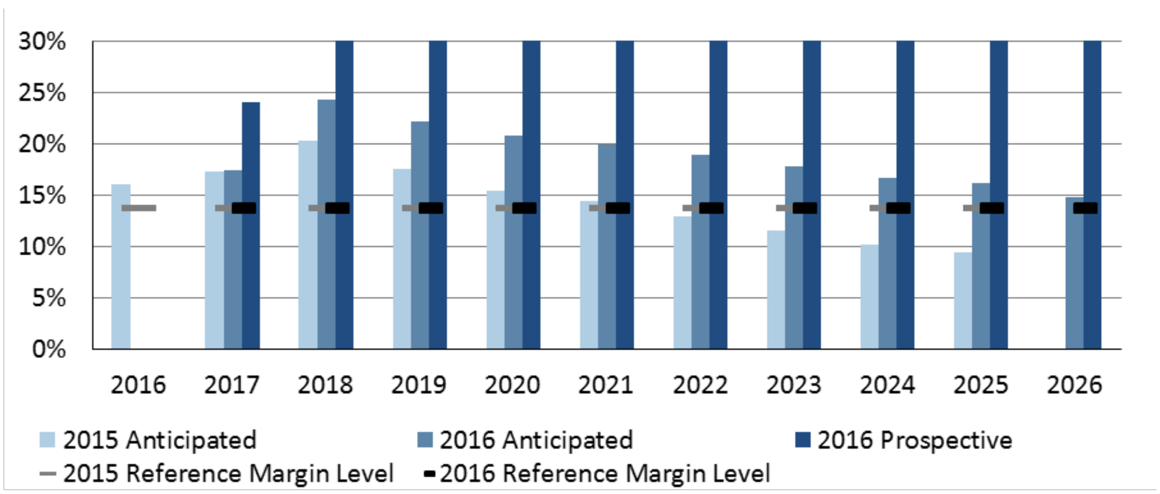


Figure 1.10: Texas RE-ERCOT 2015 LTRA and 2016 LTRA Reserve Margin Comparison

Figure 1.11 shows the results of a sensitivity analysis whereby all 6.9 GW of unconfirmed coal and natural gas retirements are included in the Anticipated Reserve Margin. From this unconfirmed retirement scenario, ERCOT would fall below their Reference Margin Level of 13.75 percent to 11.1 percent in 2021 and continue to decline to 5.8 percent by the end of the assessment period. The Prospective Reserve Margin indicates that there are sufficient Tier 2 generation in the queue that may need to be advanced to mitigate a capacity concern.

[13] ISONE- Natural Gas Infrastructure Constraints ; September 28, 2016

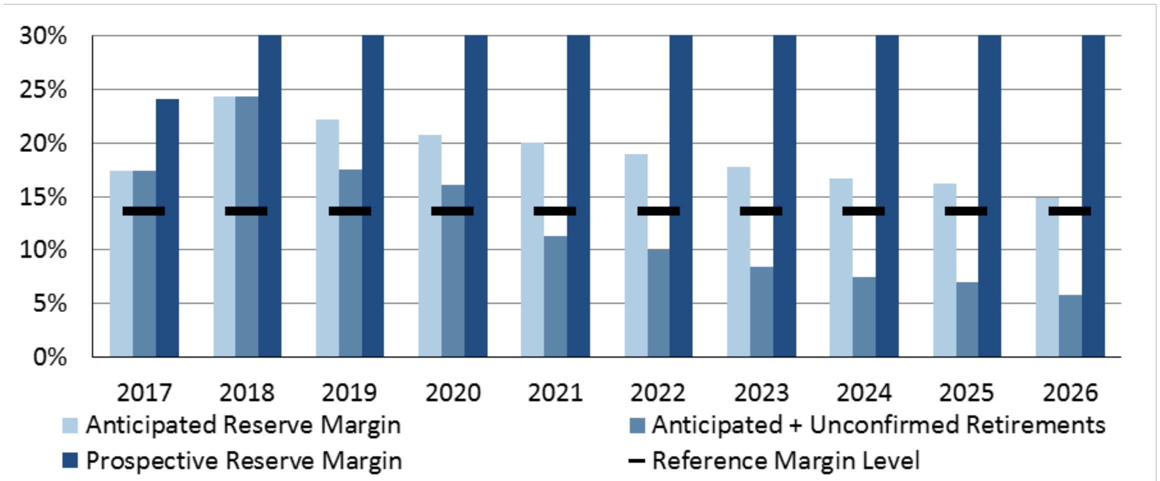


Figure 1.11: Texas RE-ERCOT Reserve Margins with Unconfirmed Retirements

Over the next ten years, installed resources in the ERCOT Region grow from 16.3 to 26.9 GW nameplate when accounting for Tier 1 planned resources. This would increase the percentage of installed nameplate wind to a total nameplate capacity from 16.5 percent to 22.6 percent. When adding wind and solar, as shown in **Figure 1.12**, variable resources are projected to be 25.3 percent of the anticipated resource capacity and 42.1 percent of the prospective resource capacity. Actual wind and solar penetration at any time of the year are dependent on weather, irradiance, and resource controllability. Very high penetration levels of variable energy resources (VERs) increases the need for ERSs to effectively dispatch conventional generating units and maintain system reliability.

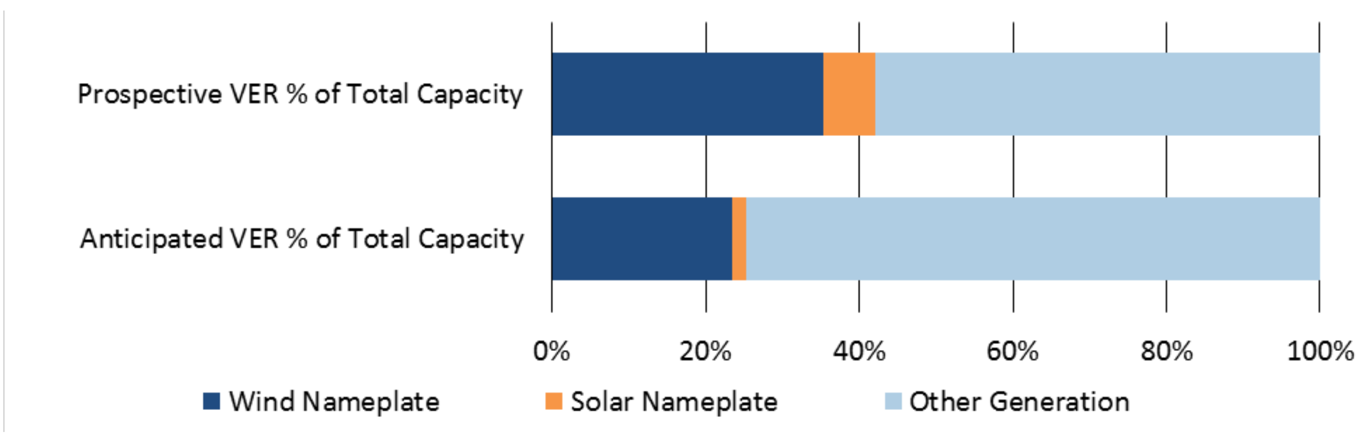


Figure 1.12: Maximum VER Penetration in ERCOT for the 2026 Summer Peak

Figure 1.13 shows the total anticipated capacity between years 2017 and 2026 for ERCOT by fuel type. Total expected net changes across the summer peak include 6.0 GW of natural-gas-fired generation and 0.8 GW of utility-scale VER additions.

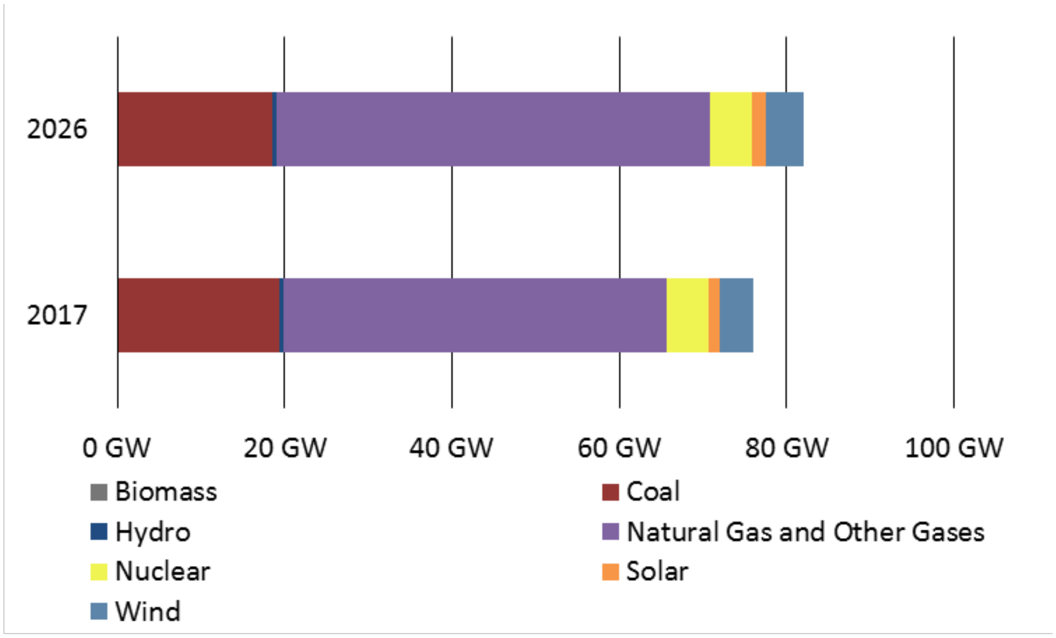


Figure 1.13: ERCOT Total Anticipated Capacity by Fuel Type

In August of 2016, ERCOT set multiple new hourly peak demand records based on preliminary data, settling on 71,197 MW on August 11th between 4:00 p.m. and 5:00 p.m.[14] At the time of this peak, 4,783 MW of wind was generating on the system, or approximately 6.72 percent of total energy over the hour.[15] System operations indicate that the system is currently capable of delivering energy generated from these wind turbines throughout the assessment area. For parts of the BPS that experience localized events where generation is over-producing in transmission constrained areas, operators must be able to control wind and solar production to prevent contingencies from overloading transmission lines. Similar to the Department of Energy study for MISO, wind curtailments were observed in ERCOT between 2007 and 2015, as shown in their August 2016 report.[16]

In December of 2015, Congress passed the *Consolidated Appropriations Act,* which extended federal renewable electricity production tax credits through the end of 2019.[17] These tax credits may encourage new renewable energy development in Texas before sufficient transmission is added that is necessary to effectively deliver this new energy to system load. ERCOT could also experience increased retirements of some fossil fuel generation due to the expected EPA's final regional haze rule[18, 19] and, if upheld by the courts, the potential impacts of the Clean Power Plan (CPP). An initial study by ERCOT also concluded that the "Regional Haze requirement would have a significant local and regional impact on the reliability of the ERCOT transmission system."[20] Both of these regulations have been stayed at this time,[21] which creates some uncertainty around the contents of their final ruling. These are currently subject to change.

14 ERCOT Bulletin: "ERCOT Breaks Peak Record Again, Tops 71,000MW for First Time"; August 11th, 2016
15 ERCOT Wind Integration Reports
16 U.S. Department of Energy: 2015 Wind Technologies Market Report: Summary; August 2016
17 Renewable Electricity Production Tax Credit Program Info; Energy.gov
18 EPA: Visibility - Regional Haze Program
19 EPA: Air Issues in Texas
20 ERCOT Presentation: Transmission Impact of the Regional Haze Environmental Regulation; October 15, 2015
21 U.S. Court of Appeals for the 5th Circuit: State of Texas et al. v. U.S. Environmental Protection Agency et al., July 15, 2016

WECC-CAMX

Similar to NPCC-New England, there are no risks identified to resource adequacy when only applying a reserve margin analysis. The Anticipated Reserve Margins, shown in **Figure 1.14**, remain above the Reference Margin Level for all years of the assessment, indicating that there are sufficient resources anticipated to be available to serve peak load.

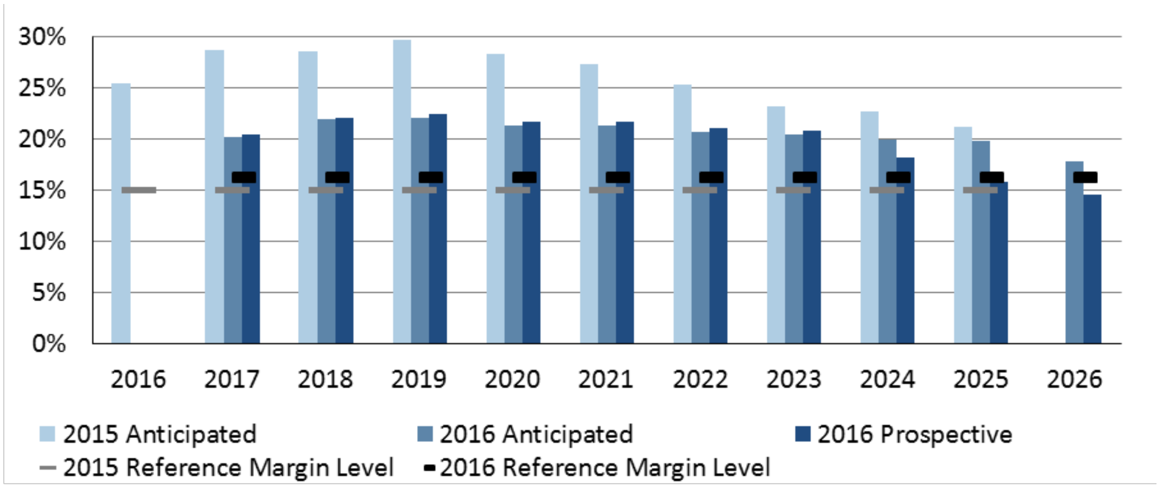


Figure 1.14: WECC-CAMX 2015 LTRA and 2016 LTRA Reserve Margin Comparison

However, once additional emerging and standing issues are incorporated into the overall resource adequacy risk analysis, the *2016 LTRA* identifies WECC-CAMX as having a medium risk to resource adequacy. This is primarily due to a high reliance on natural-gas-fired generation, limited dual-fuel capability, and the potential reduction in adequate ERSs. Additional study into WECC-CAMX's ramping sufficiency concerns are presented in the Essential Reliability Services Chapter 3.

Single Fuel Dependency

Natural gas continues to be the predominant fuel type in many assessment areas. The ten-year projection for natural gas continues to show an upward slope in the amount of natural-gas-fired resources coming onto the grid, as well as the rate for new-natural-gas fired resources to enter the BPS. Key drivers for this increase include regional initiatives; state renewable portfolio standards; past and potential future regulatory rulings, such as MATS and the CPP; and recent shale gas production. This results in historically low natural gas prices.

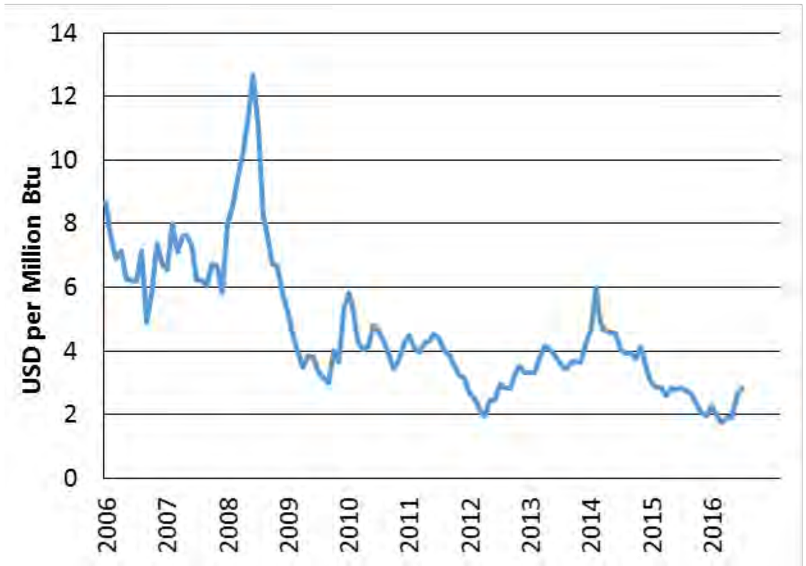


Figure 1.15: Natural Gas Spot Prices—Henry Hub

Spot natural gas prices have declined from roughly \$13/MMBtu in 2008 to below \$3/MMBtu in 2016 as shown in **Figure 1.15**.[22] This decline in prices has been a large factor in the increase in natural-gas-fired generation. Outside of the effects from regulatory rulings, the low price of natural gas has resulted in additional coal units being shut down as well as the announcement of a significant number of nuclear retirements.

Due to historically low gas prices, natural gas use for electricity generation has developed a strong market incentive over all other fuel types within the ERO footprint. The U.S. Energy Information Administration (EIA) routinely monitors monthly energy usage and forecasts. **Figure 1.16** shows natural gas usage surpassing coal for the first time in 2015 and for a majority of the time in 2016.[23]

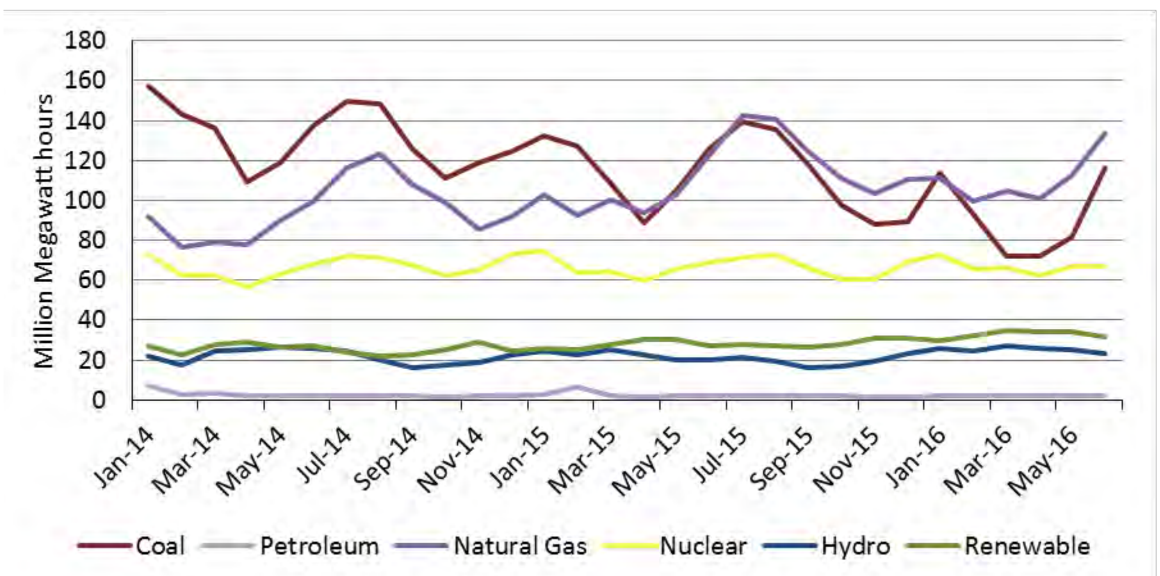


Figure 1.16: Monthly Net Electricity Generation by Fuel Type

[22] EIA Henry Hub Natural Gas Spot Prices

[23] EIA Short-Term Energy Outlook - July 2016

NERC continues to monitor and report on changes to the resource mix and the potential reliability risks associated with these changes. Several ongoing trends have been identified in past LTRAs, such as increasing natural gas, increasing wind and solar, decreasing coal, and uncertainty around the future of nuclear. These previously identified trends indicate an under-forecasted rate of change from assessment to assessment; these rates of change similarly increased in the *2016 LTRA* reference case.

Figure 1.17 shows natural-gas-fired generation data from the *2008 LTRA* through the *2016 LTRA* reference cases. While the proximity of anticipated natural gas forecasts for year two of each assessment is close to the actual amount installed, there continues to be wide margins between the outer years of each assessment. For example, in 2024 (year ten of the *2014 LTRA* and year eight of the *2016 LTRA*) there was a forecasted increase of 29.8 GW of net anticipated natural gas; this net change includes both Tier 1 designated planned additions and confirmed retirements.

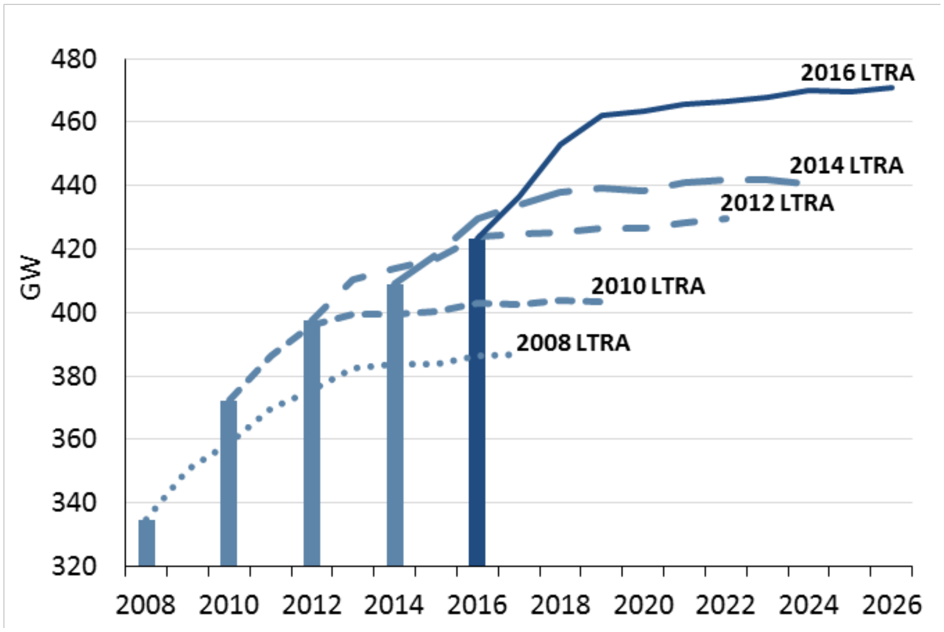


Figure 1.17: Anticipated Natural Gas Capacity by LTRA Reporting Year

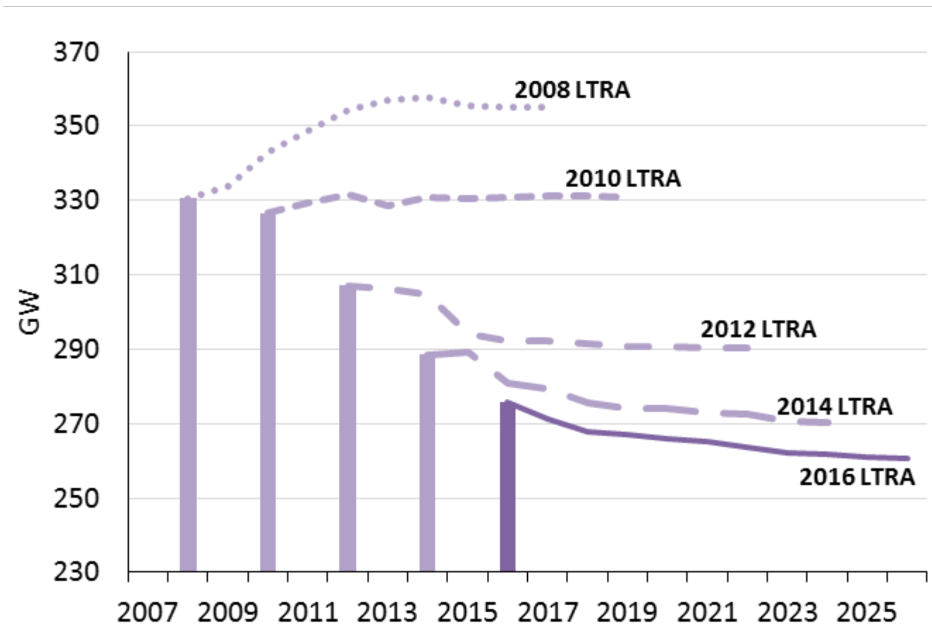


Figure 1.18: Anticipated Coal Capacity by LTRA Reporting Year

The rate of change of retirements of coal plants have continuously increased from assessment to assessment. As shown in **Figure 1.18**, coal-fired generation data from the *2008 LTRA* through the *2016 LTRA* reference cases show consistent marginal gaps between assessments. For example, by 2024 of the *2014 LTRA* and *2016 LTRA*, there was a decrease in the system-wide forecast by 8.5 GW. This trend indicates that coal generation retirements have and are continuing to outpace retirement projections.

Table 1.1 shows that a growing number of the assessment areas are trending towards an increasing dependency on this single fuel source. The table shows a breakdown by assessment area for natural-gas-fired capacity as a percentage of the area's total anticipated capacity. NERC has identified a dependency on a single fuel as a potential reliability risk requiring mitigation. Natural gas has crossed over 50 percent of peak capacity in several areas amidst continued historically low prices and regulatory rulings, which continue to promote increased natural gas generation.

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity

	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
FRCC	35,583	39,598	66.19%	69.05%
WECC-CAMX	40,299	42,536	68.39%	68.23%
Texas RE-ERCOT	45,842	51,867	60.34%	63.26%
NPCC-New England	14,331	16,308	48.17%	52.33%
WECC-SRSG	16,530	16,774	51.24%	51.84%
WECC-AB	8,514	8,514	52.02%	51.79%
SERC-SE	30,256	30,262	48.53%	46.88%
MRO-SaskPower	1,835	2,087	42.90%	43.97%
SPP	30,413	29,446	45.92%	45.22%
SERC-N	19,250	21,160	37.96%	40.68%
MISO	59,566	60,026	41.74%	42.26%
NPCC-New York	16,030	16,708	41.07%	41.98%
PJM	66,760	76,335	35.80%	38.71%
WECC-RMRG	6,695	6,914	36.36%	38.51%
WECC-NWPP-US	20,860	20,565	34.67%	34.80%
SERC-E	15,762	17,754	30.67%	32.25%
NPCC-Ontario	6,568	7,340	22.99%	24.91%
NPCC-Maritimes	856	856	12.56%	12.66%
MRO-Manitoba Hydro	311	404	5.51%	6.33%
WECC-BC	434	442	3.45%	3.48%
NPCC-Québec	-	570	0.00%	1.33%

Figure 1.19 shows the aggregated summer capacity heat map for all operating and planned natural gas generating units within the ERO footprint. This figure clearly shows that large pockets of natural gas generation are occurring throughout the footprint and evenly spread out. This causes some areas to potentially be more reliant on this single fuel type.

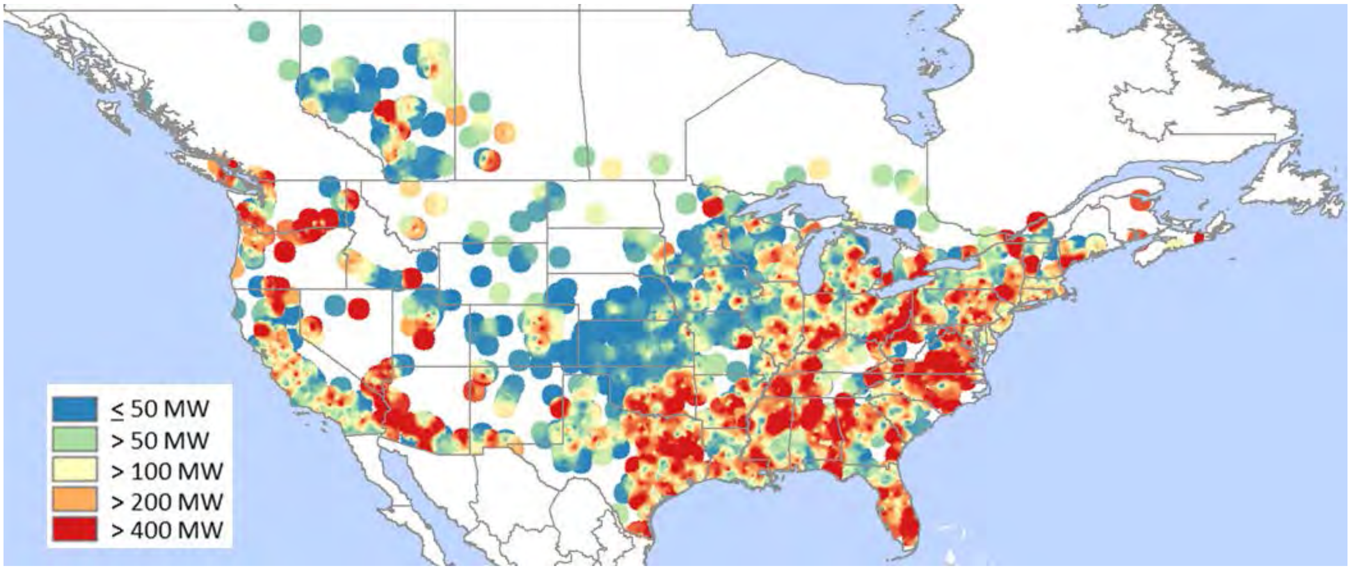


Figure 1.19: Natural Gas Generating Units–MW Summer Capacity Heat Map

NERC conducted a short-term special assessment in 2016 that included an operational risk analysis using NERC's Generation Availability Data System (GADS) database to project natural-gas-fired outages.[24] Using a deterministic approach, all evaluated assessment areas showed no concerns in meeting reserve margin requirements as a result of this operational risk assessment. However, when a single point of disruption, such as unavailable storage facilities, pipeline rupture, or other gas infrastructure failure was considered, reserve margins were jeopardized in some areas. For example, the Aliso Canyon outage in Southern California illustrates the effects of a potential single point of disruption. This one underground gas storage facility in SoCal Gas' service territory contains 86 BCF of gas capacity, providing fuel to approximately 9,800 MWs of electric generation. The facility also supports ramping requirements to accommodate the variability of renewable energy resources. This outage has the potential to cause rolling black outs in Southern California until the facility is completely operational again or other mitigation approaches have been employed.

[24] NERC: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation; May 2016

Gas storage facilities have historically had clear delineations between a summer injection season and winter withdrawal season. **Figure 1.20** shows the daily total injections and withdrawals to and from underground gas storage facilities from April–August 2016. Multiple days within this time period have seen net changes that resulted in more withdrawals than injections. While this is not the first time that system-wide underground storage facilities saw a net withdrawal during the summer season, any continuing changes to use trends for natural gas storage inventories should be monitored and evaluated for potential impacts to future gas availability.

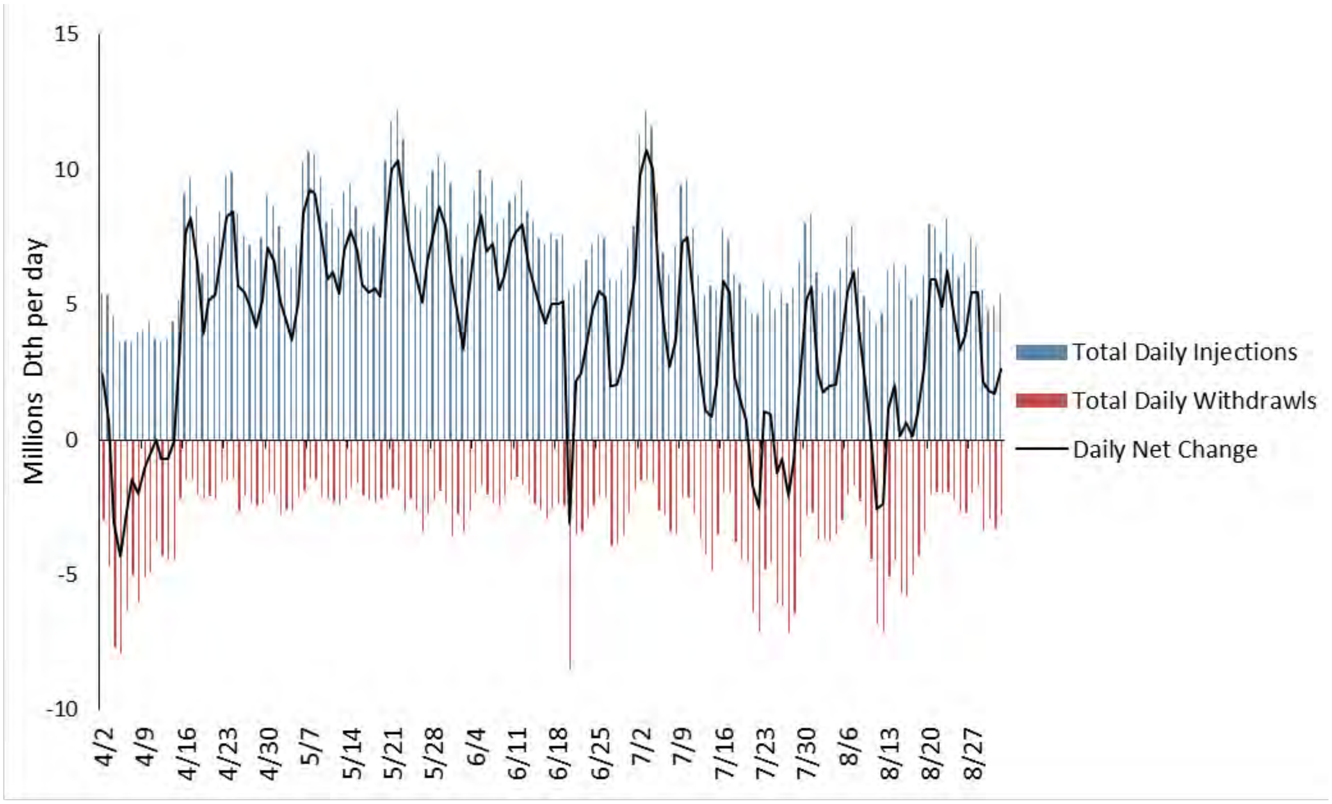


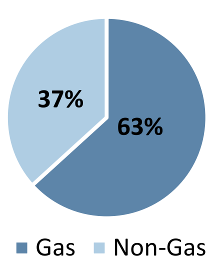
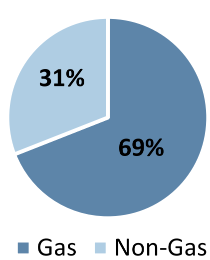
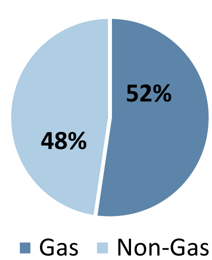
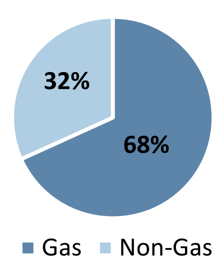
Figure 1.20: 2016 Weekly Natural Gas Inventory Changes

Many factors must be considered when assessing the potential for reliability risks in resource planning, as outlined in TPL-001-4[25]. Each assessment area is comprised of a unique set of variables that include existing resources, electric transmission, and natural gas infrastructure. NERC has identified areas that are increasingly reliant on a single fuel type, which increases vulnerabilities, particularly during extreme weather events and conditions. Over the past decade, several areas have significantly increased their dependence on natural gas. This trend has continued amidst historically low natural gas prices and regulatory rulings that continue to promote increased natural gas generation. The assessment identifies four assessment areas with high penetrations of natural gas generation and therefore increased risk through single-fuel dependency: Texas RE-ERCOT, FRCC, NPCC-New England, and WECC-CAMX. **Table 1.2** provides a summary of various independent factors that influence these four assessment areas' capability to mitigate an increasing reliability risk.

[25] NERC TPL-001-4

Table 1.2: Single Fuel Dependency Risk Summaries				
	Texas RE-ERCOT	**FRCC**	**NPCC-New England**	**WECC-CAMX**
Factors that Reduce Risk				
Alternative Fuel Capabilities Evaluate capabilities across generator fleet, maintain back-up fuel inventories at key stations, and annually test fuel-switching capability	14% of gas-fired generation is capable of using alternative fuel. No requirement to maintain back-up fuel inventory Testing of fuel switching is not required Annual winterization and cold weather preparation workshops share lessons learned and best practices to improve reliability during extreme cold weather.	73% of gas-fired generation is capable of using alternative fuel. Back-up fuel inventories are required by the state public utility commission.	30% of gas-fired generation is capable of using alternative fuel. Winter Reliability Program (through 2018) provides payments for adding dual-fuel capability, securing fuel inventory, and testing fuel-switching capability; compensation for any unused fuel inventory.	4% of gas-fired generation is capable of using alternative fuel. Very limited back-up fuel kept in inventory; holding tanks have largely been removed.
Market and Regulatory Rules Provide additional incentives for behavior and investments that support reliability and resiliency	No regulatory or market rules exist for maintaining dual-fuel capability and/or firm natural gas transportation.	Regulatory rules exist for maintaining dual-fuel capability and firm natural gas transportation services and contracts.	Recent market rule changes include energy market offer flexibility, timing adjustments to Day-Ahead Energy Market, Winter Fuel Reliability Program, and Pay-for-Performance (which starts in June 2018) By creating incentives, the market may indirectly provide incentives for the development of on-site oil, LNG fuel storage, or expanded gas pipeline infrastructure.	No regulatory or market rules exist for maintaining dual-fuel capability and/or firm natural gas transportation within CAISO.

Single Points of Disruption Assess reliability under extreme conditions, loss of major pipeline infrastructure or supply	Meshed pipeline infrastructure significantly reduces this risk	The fleet of dual fuel capable generation and ensuring sufficient fuel inventory reduces this risk.	Area is situated in bottlenecked and physical end of the interstate pipeline system. Two major interstate pipelines connected from southeast; one from the northwest.	Area is situated in bottlenecked and physical end of the interstate pipeline system. Two major interstate pipelines connected from southeast; one from the northeast. Aliso Canyon Storage Facility outage continues to impact fuel deliveries.
Pipeline Expansion Keep pace with generation expansion and increasing electricity production	No signs of concern with lagging pipeline expansion Natural gas generation is coming on-line with Firm transportation service.	Two projects to be completed in 2017 reduce this risk: Sabal Trail Transmission and Florida Southeast Connection. Dual-fuel capabilities reduce the risk	State policies and pressures have not led to the construction of natural gas pipelines Recent suspension of pipeline projects aimed to support electric generation	No interstate transmission projects that increase pipeline capacity approved by FERC since 2009. Intra-state projects are more likely; however, political opposition continues to challenge expansion (such as in the SoCal Gas North-South Project)
Limited Exposure to Supply Chain Failure Increase resiliency by maintaining alternative supply chains and paths	Robust supply sources within service area; conventional, shale, and gulf sources	Gas supplied from conventional, shale, and gulf sources and transported to Florida; potential LNG import. No local production	Gas supplied from conventional, shale, and gulf sources and transported to New England; limited LNG import (supplies Mystic Generation Station~2,000 MW) No local production; no storage	Gas supplied from conventional, shale, and gulf sources and transported to California. Some local production

Maintaining Situational Awareness Electric system operators need awareness of pipeline conditions and must be able to predict generators that may become unavailable	Pre-season surveys of fuel inventories Coordination with pipeline operators	No significant changes	Pre-season surveys of fuel inventories Improved coordination and information-sharing with natural gas pipeline operators Coordination of generator and pipeline maintenance schedules. Gas Usage Tool estimates the remaining gas pipeline capacity by individual pipe for use by ISO-NE system operators	Improved coordination and information-sharing with natural gas pipeline operators Joint Agency Daily Reliability Communication (throughout Aliso Canyon outage) Development of gas curtailment methodology and scenario planning Active coordination on energy emergencies with California Energy Commission; action plans to respond to Aliso Canyon Storage Facility outage.
Risks Communicated to Policymakers Results and conclusions of studies that evaluate electric reliability should be shared and clarified with state, federal, and provincial policymakers and regulators	Gas Curtailment Risk Study (2012) Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA Key participant in the Eastern Interconnection Planning Collaborative (EIPC) gas-electric interface study NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment. WECC is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.
Maintain Fuel Diversity Maintaining fuel diversity provides inherent resiliency to common-mode risk				

Recognizing the increased dependence on natural gas as a fuel for electricity generation, FERC has already taken steps to improve the coordination of wholesale natural gas and electricity market scheduling:

- FERC Order No. 787, issued on November 15, 2013 (Rulemaking RM13-17-000),[26] provides explicit authority to interstate natural gas pipelines and public electric utilities participating in the interstate commerce to share nonpublic operational information with each other to promote reliable service or operational planning on their systems.
- FERC Order 809, issued on April 16, 2015 (Rulemaking RM14-2-000),[27] provides for better coordination of the scheduling practices of the wholesale natural gas and electric industries, as well as additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts.

However, regulatory and policy solutions that help expand pipeline access, reliability, and the needs of electric generation have a not surfaced. The recent suspension of Kinder Morgan's AED and Algonquin's proposal to facilitate electric utility purchase of pipeline capacity demonstrates the need for regulatory solutions to facilitate electric generator commitments. This is particularly true for generation operating in wholesale electric markets.

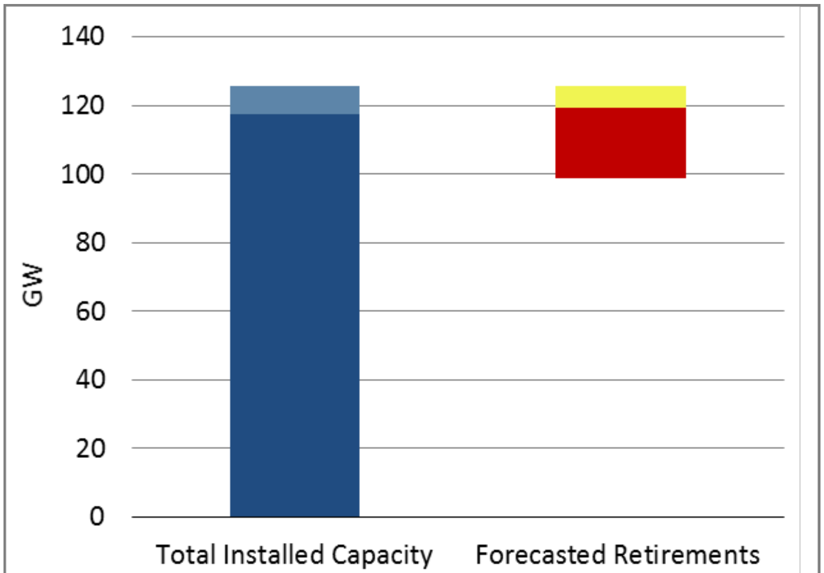
Recommendations

As natural-gas-fired resources continue to increase, system planners and operators should evaluate the potential effects of an increased reliance on natural gas as it pertains to BPS reliability. Natural gas provides "just-in-time" fuel; therefore, firm transportation and maintaining dual-fuel capability can significantly reduce the risk of common-mode failure and wider-spread reliability challenges. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability. Regulatory action may be needed to better calibrate electric and gas industries.

[26] FERC Order 787; U.S. Docket No. RM13-17-000
[27] FERC Order 809; U.S. Docket No. RM14-2-000

Nuclear Uncertainty

Lower natural gas prices driven by abundant domestic supply, along with other economic and regulatory factors, have pressured the economic viability of 99 operable nuclear units. Confirmed and unconfirmed retirements of facilities are projected in California (Diablo Canyon), Illinois (Quad Cities and Clinton), Massachusetts (Pilgrim), and Nebraska (Fort Calhoun) during the next ten years. Other at-risk units are located in the northeastern states. Uncertainties and contributing factors to nuclear retirements include high operating costs with low prevailing power prices, regulatory issues, and public opposition.[28] **Figure 1.21** shows the forecasted and potentially advanced total nuclear capacity that could be affected. It is projected that 6.4 GW of capacity is ready to retire; this makes up five percent of the total installed capacity by 2026. The High Nuclear Retirement Case capacity values from NERC's *Clean Power Plan; Phase II Assessment*[29] indicate that a potential total of 26.8 GW, or 21 percent of all anticipated nuclear capacity, could be at risk to retire under this scenario.



Total Installed Capacity (GW)	**125,587**
Existing as of 2016	117,649
Projected	7,938
CPP High Nuclear Retirement Case (GW)	**26,800**
Forecasted LTRA	6,403
Additional to reach CPP case	20,397

Figure 1.21: Anticipated Nuclear Capacity by 2026

New York regulators recently introduced an energy plan that will preserve the economic viability of three upstate units. However, the retirement of seven remaining at-risk units would continue a recent trend since 2012 of decommissioned units in Florida (Crystal River), Wisconsin (Kewaunee), California (San Onofre), and Vermont (Vermont Yankee). Despite economic pressures on existing units, the Tennessee Valley Authority (TVA) started the Watts Bar two unit in mid-2016, following nearly three decades of a sluggish pace for new unit builds. According to the *2016 LTRA* Reference Case, four additional units are expected to be completed by 2021. These additions, combined with ongoing uprates to existing units in the United States, will result in a continued steady contribution of nuclear power over the next ten years.

Similar legislation was passed by the Illinois General Assembly that would authorize subsidies totaling $2.4 billion over the next decade to allow both Quad Cities and Clinton nuclear facilities to remain open.[30]

Recommendations

NERC should continue to monitor the potential effects of nuclear retirements on overall resource adequacy as well as potential mitigating factors such as state regulatory measures that provide incentives for nuclear facilities to remain operational.

[28] World Nuclear: Nuclear Power in the USA; September 26, 2016
[29] Potential Reliability Impacts of EPA's Clean Power Plan Phase II; May 2016
[30] Illinois General Assembly: Bill Status of SB2814

Chapter 2: Probabilistic Analysis

Probabilistic analyses describe events in terms of how probable they are and include performance characteristics of BPS components, such as generator outage rates, resource realizations in terms of energy produced, load characteristics, and transmission congestions or constraints. A prediction of future reliability must be expressed in terms of the expected performance of the system components and the uncertainty in those expectations. Probabilistic methods typically rely on either statistical analyses of historical performance or enumeration techniques that are capable of simulating large numbers of contingencies. However, the choice of methods and selection of acceptable reliability levels are still matters of judgment and differ from Region to Region (and from utility to utility in some cases).

The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate system Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP) values.[31] The one-event-in-ten-year (0.1 events per year) LOLE is produced from this type of probabilistic analysis. This planning criterion requires an electric system to maintain sufficient capacity such that system peak load is not likely to exceed available supply more than once in a ten-year period. Utilities, system operators, and regulators across North America rely on variations of the one-event-in-ten year criterion for ensuring and maintaining resource adequacy.

Sensitivity Model

Sensitivity analyses around Monto-Carlo-simulated reserve margins can be run by treating specific (independent) variables as random. To demonstrate how any independent variables impact reserve margin results, a simulation was run for a generic summer-peaking system. **Figure 2.1** shows the resulting reserve margin uncertainties from 2018 to 2026 using probabilistic distributions of wind and solar power from actual time series profiles. Due to the random variability of the simulated wind and solar, the uncertainty around the calculated reserve margin mean is demonstrated. This is indicated in the figure whereby the area in blue shows the resulting bandwidth of one standard deviation from the mean and the grey shows two standard deviations from the mean.

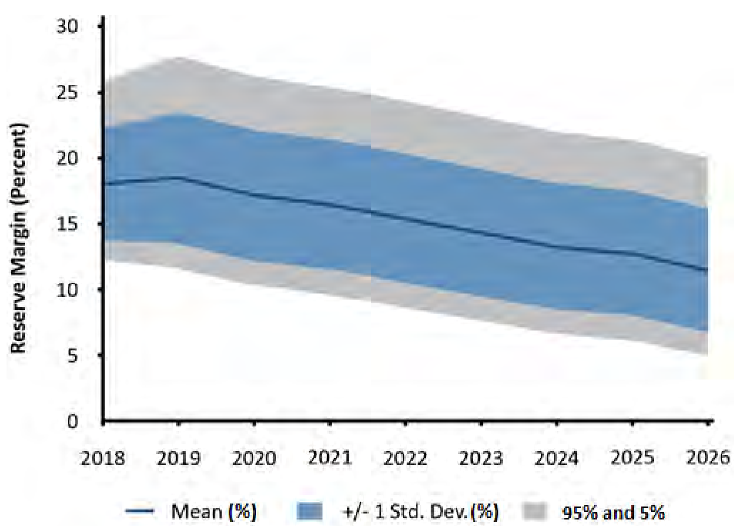


Figure 2.1: Reserve Margin Uncertainty Due to Wind and Solar Variability

[31] A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below one day in ten years. Loss-of-Load Expectation (LOLE) is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently, some Assessment Areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day.

This generic model was further explored by running additional simulations to other applied independent variables. DSM, Tier 1 capacity resources, and firm transactions risk profiles are developed based on historical statistical performance data provided in the NERC 2015 Electricity Supply & Demand database and the use of engineering judgments. **Figure 2.2** shows a tornado diagram highlighting the sensitivity of these other input parameters and ranking them by their effect on reserve margin mean values for 2016. The figure ranks the sensitivity of an output reserve margin from different independent variables. The following variables were considered for this analysis: demand, wind, solar, demand-side management (DSM), existing-certain resources, Tier 1 resources, and firm capacity imports and exports. **Figure 2.2** shows how much a one standard deviation change in input variables affects the output reserve margins. The width of each parameter directly represents the impact an independent variable can have on reserve margins and the degree of which uncertainty can be assumed.

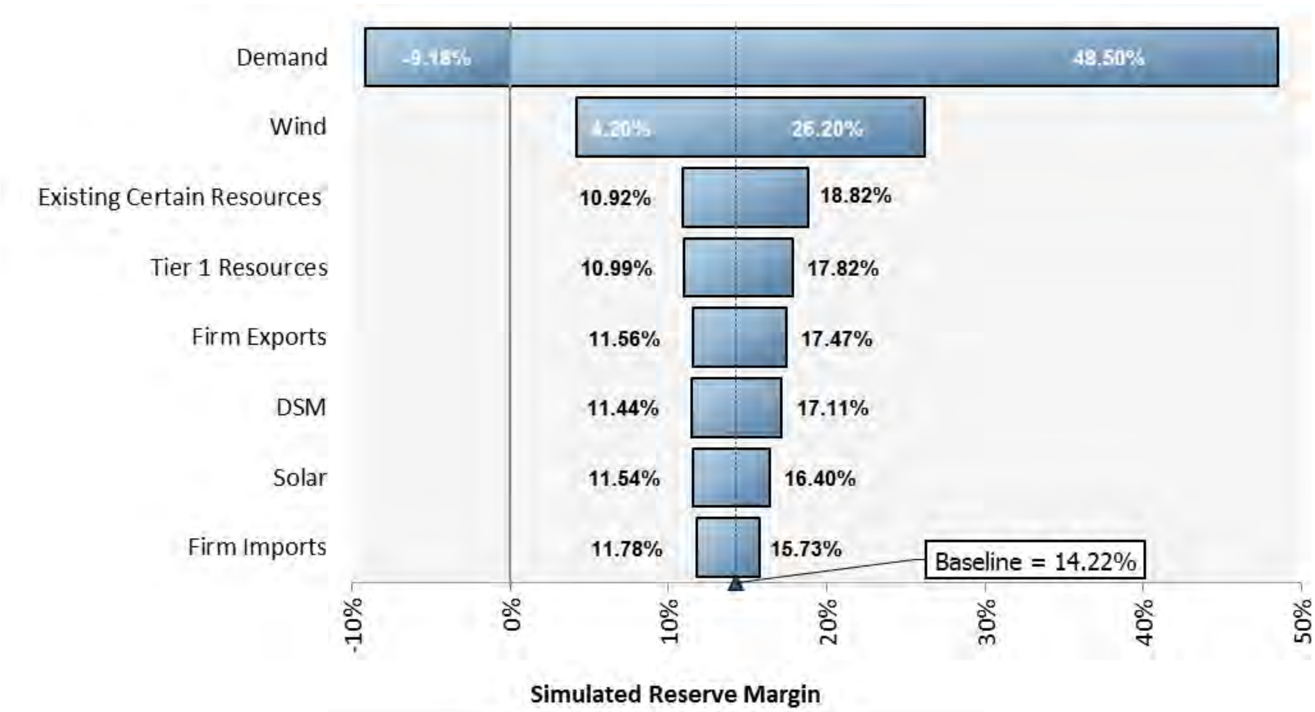


Figure 2.2: Tornado Plot for 2016 Simulated Reserve Margin Ranked by Effect of the Reserve Margin's Mean

Probabilistic distributions were assigned to hourly demand, wind, and solar power profiles. Additionally, risk profiles were applied to DSM, Tier 1 capacity resources, and firm transactions based on past performances. The results in **Figure 2.2** shows that demand is the most impactful parameter that drives this generic system's simulated reserve margin. Specifically, accurate load modeling and forecast uncertainty modeling are critical aspects for effective resource adequacy planning. The second most sensitive parameter is wind power due to the large percent share of the system's generation mix. This analysis also shows the least sensitive and least influential input parameter is solar due its relatively small percent share of the generation mix.

As each system includes a unique set of independent variables, and this type of analysis is helpful in determining the most significant parameters of a given system. Planners can then judge which risks to take and which ones to avoid in maintaining resource adequacy while allowing for best operational and planning decisions under prevalent uncertainty.

VER Capacity Contributions

For a reserve margin analysis, the capacity contributions of installed variable energy resources (VERs) are the values that are expected to be available to an assessment area across the peak load hour. The calculation of the capacity contribution of conventional generating units are straightforward and are based on unit performance ratings, forced outage rates, and annual unforced maintenance cycles. However, the capacity contributions of VERs are not intuitive due to their inherent characteristics. There are two major attributes of variable generation that notably impact bulk power system planning and operations:[32]

- **Variability**: The output of variable generation changes according to the availability of the primary fuel (e.g., wind, sunlight, and moving water), resulting in fluctuations in the plant output on all time scales.
- **Uncertainty**: The magnitude and timing of variable generation output is less predictable than for conventional generation.

Many factors are affecting the system-wide increases of renewable resources and are the predominant choice for renewable energy integration. In high-VER penetration conditions, a larger portion of the total resource portfolio will be comprised of energy-limited resources when applied to today's power system. This fact somewhat complicates, but does not fundamentally change, existing resource adequacy planning processes as they are still driven by a reliability-based set of metrics. Resource adequacy can be confirmed through detailed reliability simulations that compare expected demand profiles with specific generating unit's forced outage rates and maintenance schedules to yield LOLE or LOLP values. Reliability simulations typically include probabilistic production cost simulations for meeting a specified demand curve (or chronological curve) from a specified generation fleet while incorporating the forced and unforced outage rates over the simulation period.

Current approaches used by resource planners fall into four basic categories:[33]

- A rigorous LOLE/LOLP-based calculation of the effective load-carrying capability (ELCC) of variable generation relative to a benchmark conventional unit
- Calculation of the capacity factor of the variable generation during specified time periods that represent high-risk reliability periods (typically peak hours)
- A tailored approach for applying a historical performance rolling average (typically 2–3 year)
- Applications based on policies established through a nontechnical analysis

[32] More details on variable generation attributes can be found on the now-disbanded Integration of Variable Generation Task Force Special report on Standard Models for Variable Generation

[33] More information of these approaches can be found in NERC's Special Reliability Assessment: Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning

The capacity contribution component of VERs differs greatly from that of conventional generation. Conventional generation uses typical summer and winter ratings that do not differ greatly from the nameplate capacity rating. Because the capacity contributions from VERs are a statistical representation of normal operations, NERC monitors the methods and assumptions for calculating these components. In addition to assessment areas using varying methods to calculate capacity contributions for future generation, additional variances arise when considering areas with capacity market structures. **Figure 2.3** and **Figure 2.4** show the wind and solar nameplate values and their on-peak capacity contributions anticipated by all applicable assessment areas for 2021.

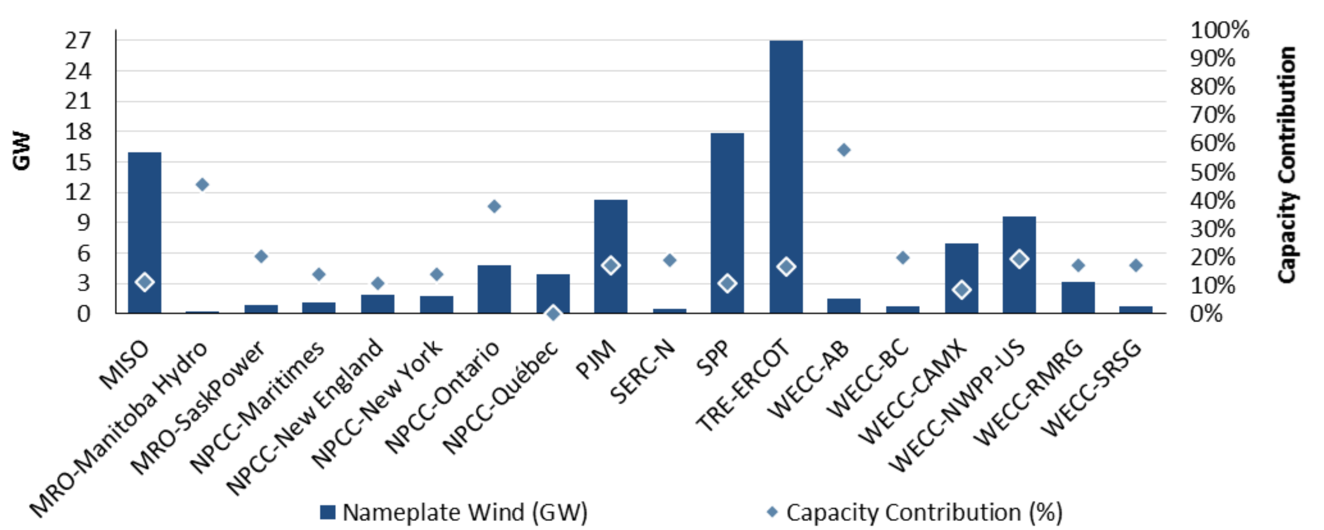


Figure 2.3: 2026 Existing and Tier 1 Wind

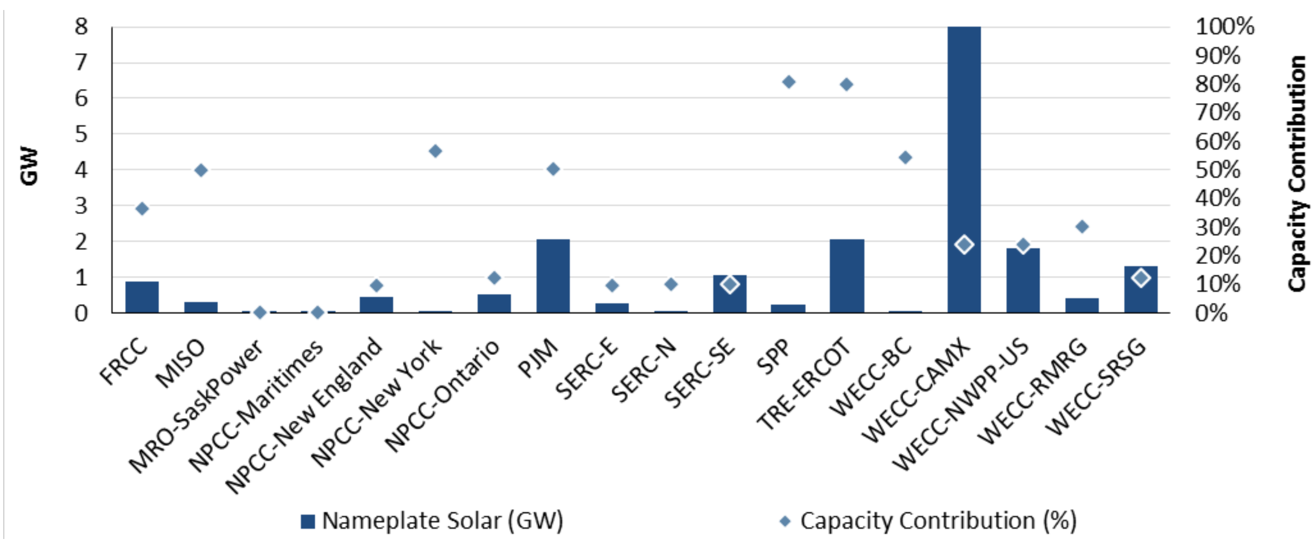


Figure 2.4: 2026 Existing and Tier 1 Solar

A generic summer-peaking model was further explored to analyze any changes to reserve margin requirements due to changes in VER capacity contribution levels. This additional analysis maintained an equal quantity of all resource types but applied a high and low capacity contribution for both solar and wind units. **Figure 2.5** shows that for higher VER capacity contributions, the Reference Margin Level would need to be increased to maintain a constant LOLE of 0.1 days per year. If capacity contributions are calculated accurately or conservatively, then the current Reference Margin Level would be sufficient.

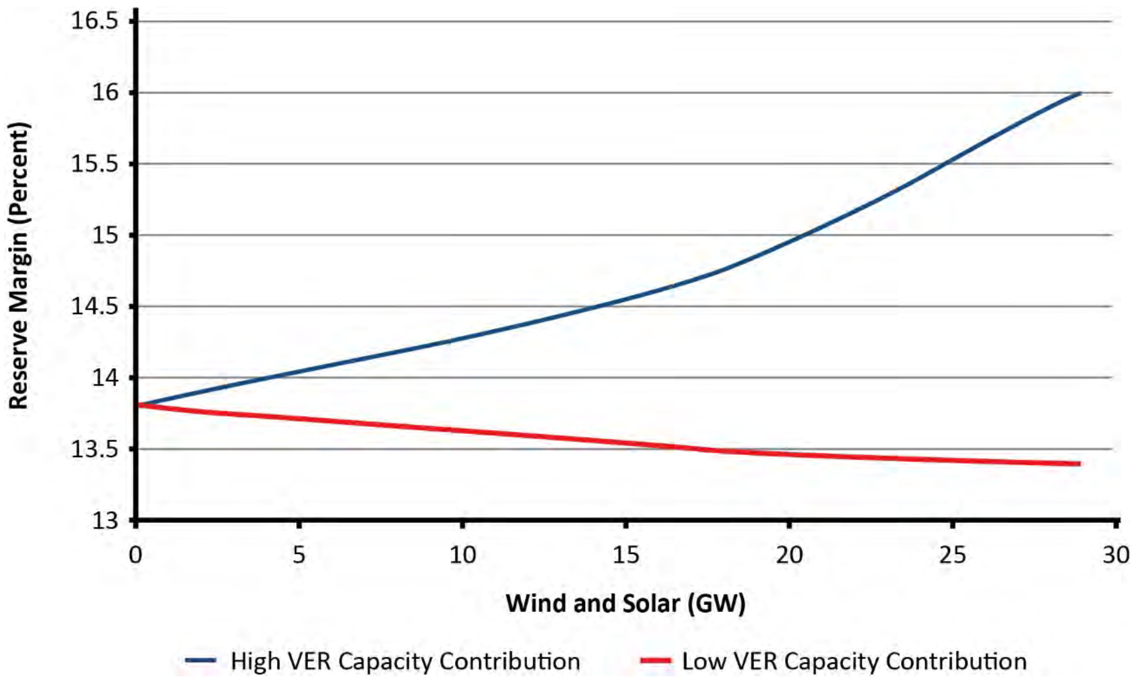


Figure 2.5: Reference Margin Level Increases with Added VER

Due to the identified relationship between Reference Margin Level and VER capacity contributions, consistent and accurate methods are needed. There are existing simplified approaches to calculate VER capacity values, and these can be easily extended to cover other forms of variable generation. In general, these methods calculate the resource's capacity factor over a time period that corresponds to system peaks. These approaches can provide a reasonable, simple approximation for capacity values. However, system characteristics, in some cases, may result in a mismatch between a rigorously calculated ELCC and a peak-period capacity factor as an approximation of capacity value. Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of any approximation.

Chapter 3: Essential Reliability Services

The North American electric grid is experiencing a shift in the resource mix, driven by a variety of factors that include retirements of conventional resources and the integration of new resources. This leads to potential impacts on essential reliability services (ERSs), such as frequency, voltage, and ramping capability. This transformation in the resource mix will change the planning and operation practices of the current electric grid. Although many resources are able to provide the essential services needed to maintain BPS reliability, understanding system characteristics and related behaviors will aide in successful integration of new technologies. BPS planning and operations will be tailored to incorporate this transformation in order to maintain reliability.

In order to study these implications, NERC formed the Essential Reliability Services Task Force (ERSTF), which produced its final report in December 2015.[34] The report studied the three reliability blocks: 1) Frequency Support, 2) Voltage Support, and 3) Net Demand Ramping Variability. The task force developed a total of nine measures for the essential services, conducted data analyses for five of them using three years of historical data and three years of forward looking data, and proposed considerations for industry practices for the remaining measures. In addition, the task force studied the potential impact of a substantial penetration of distributed energy resources (DERs) that, in aggregate, could impact the reliability of the BPS. Finally, the report recommended the developed measures be continually monitored for any trends that could potentially impact reliability. A summary of the recommendations from the framework report are listed below:

- All new resources should have the capability to support voltage and frequency. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
- The measures are intended to highlight aspects of reliability that could suggest future reliability concerns. They should be addressed with suitable planning and engineering practices.
- Planning and operating entities should use industry practices that will help ensure that emerging concerns are addressed with system specific planning and engineering practices.
- The task force recognized that DERs will increasingly affect the net distribution load that is observed by the BPS. Pursuant with NERC's reliability assessment obligations, the ERSTF further recommends that NERC establish a working group to examine the forecasting, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating and engineering practices, and policy oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.[35]
- The reliability of the system can be maintained or improved as the resource mix evolves, provided that sufficient amounts of ERSs are available. This can be achieved by sharing of experiences and lessons learned around the industry.

In 2016, the ERSTF transitioned to a working group (now known as ERSWG) and was charged with examining methodologies to determine sufficient levels of each ERS. In addition, this working group was asked to form a task force under their purview to address challenges and potential risks from increasing DERs.

The ERSWG is presently formulating a whitepaper that focuses on methods to develop sufficiency guidelines around the proposed ERSTF measures. These sufficiency guidelines are more process oriented and include the following: frequency response, voltage limits, and ramping models that tend to vary by particular area and Balancing Authority. The whitepaper further explores important technical considerations so the industry can understand, evaluate, and prepare for the increased deployment of variable energy resources (VERs), retirements of conventional coal units, increases in demand response (DR) and distributed technologies, and other changes to the traditional characteristics of generation and load resources. The working group is currently in the process of

[34] ERSTF Final Measures Framework Report
[35] The Distributed Energy Resources Task Force (DERTF) was created in early 2016

collecting data for the proposed measures and evaluating them by using the sufficiency methodology, the results of which will be finalized by end of 2017.

Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia, primary frequency response (PFR), and secondary frequency response. Working in a coordinated fashion, these characteristics and services arrest the decline in frequency and eventually return the frequency to the desired level. **Figure 3.1** below shows a typical frequency excursion and recovery, whereby the red line indicates the initial rate of change of frequency (RoCoF) due to inertial responses from synchronous machines.

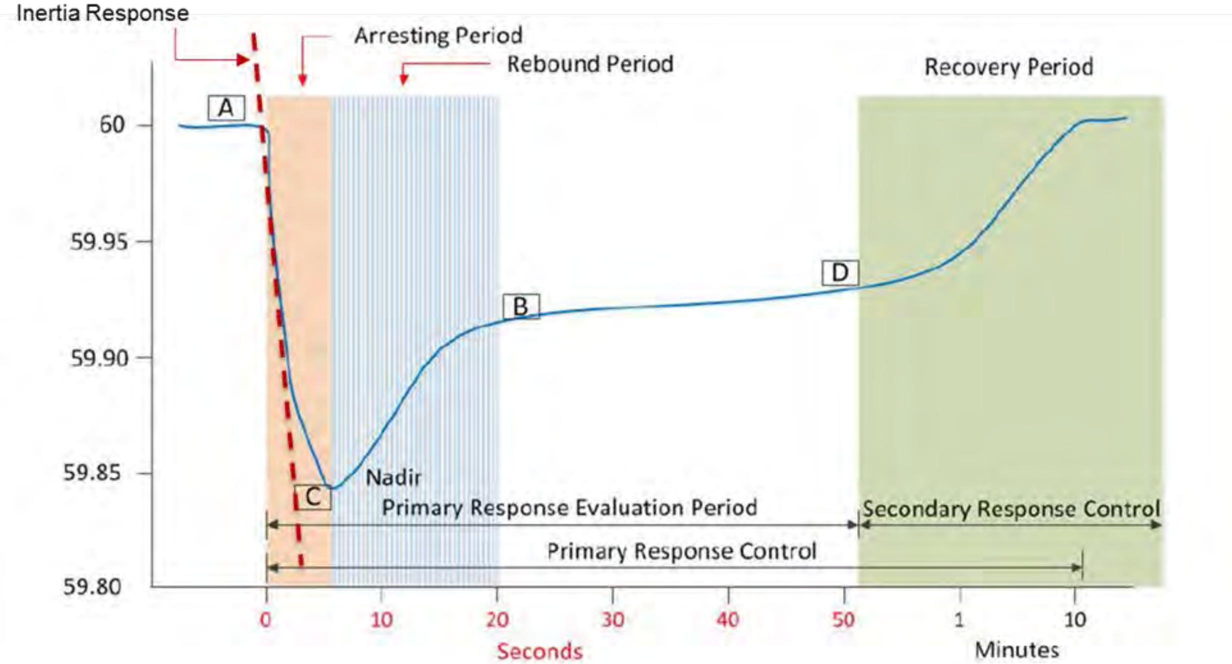


Figure 3.1: Typical Frequency Excursion and Recovery

It is important to determine various levels of inertia for a future resource mix to ensure that the system doesn't fall below a minimum level. Some newer technologies, such as wind turbines, provide the capability to inject real power at a fast rate during a frequency excursion, and thus all resources need to be taken into account in planning and operating considerations of a system. With the increasing use of nonsynchronous generation and other electronically-coupled resources (both generators and loads), the level of synchronous inertial response is reduced. This leads to a need to consider both the amounts of synchronous inertia and the available amounts of PFR based on expected conditions.

Frequency support encompasses inertia, nadir, PFR, and secondary frequency response. While inertia is just a component of overall frequency response, it plays an important role in arresting the RoCoF and prevents the nadir from reaching the level of under-frequency load shedding. Measure 4 evaluates the detailed anatomy of a frequency excursion, such as adding the calculation of Point C and time parameters in a typical event as shown in **Figure 3.1**. Measure 4 will be analyzed further in the 2017 State of Reliability Report for analysis of qualified 2016 frequency events. Measures 1–3 in the *ERSTF Framework Report* analyze the inertia and associated RoCoF. The results of data gathering for inertia and RoCoF measures for ERCOT and the Eastern Interconnection (EI) are presented here.

ERCOT

In Texas, ERCOT determined it is important to track system-level inertia in real-time to ensure system reliability. **Figure 3.2** shows the snapshot of ERCOT's real-time dashboard for inertia. The operator is able to observe total inertia and load in this single display. The dashboard also shows 24-hour inertia contributions by generator type. Monitoring by types of resources is done to enable more granular analysis of inertia trends in real-time.

Figure 3.2: ERCOT Dashboard to monitor real-time inertia

As part of the trend monitoring of ERSWG Measures 1-3, ERCOT (and other interconnections) started collecting the inertia data on June 1, 2016.

Figure 3.3 represents the inertia data for ERCOT by hour in box plot format. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma (i.e., represent 99.3 percent coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses).

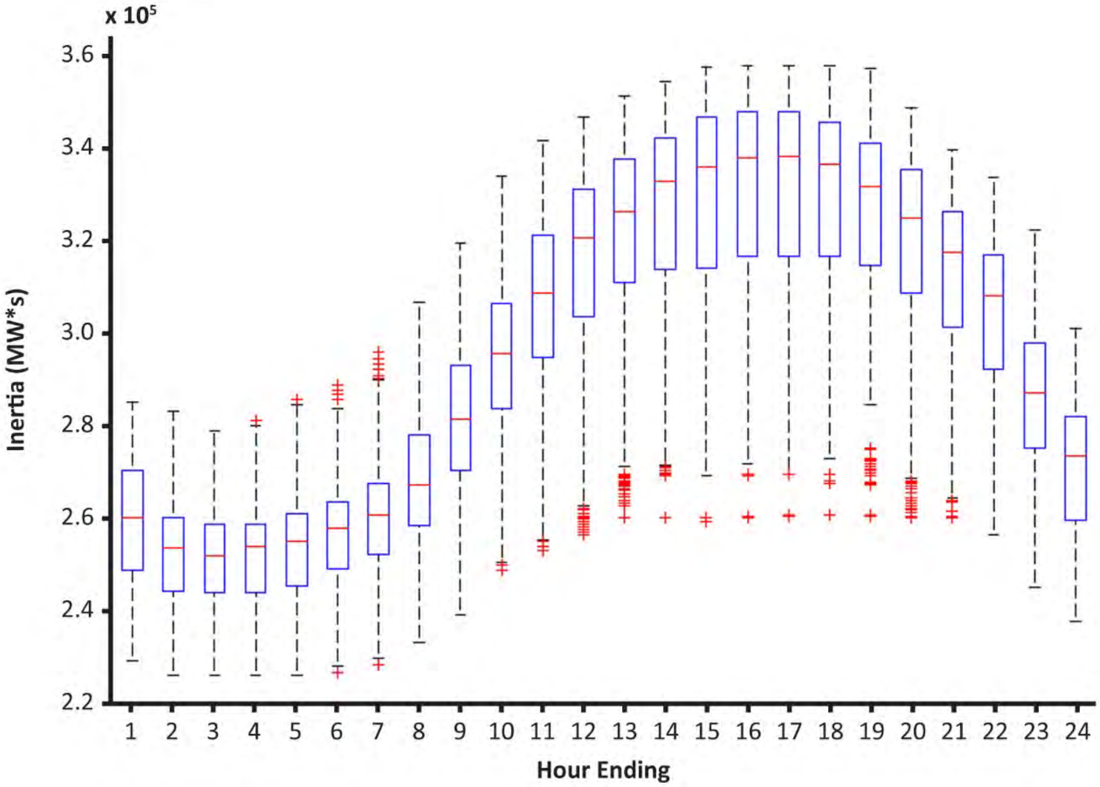


Figure 3.3: ERCOT Inertia by Hour of Day (June 1–July 15 2016)

Figure 3.4 represents a more granular version of **Figure 3.3** in that it shows ERCOT's inertia data in 15-minute intervals. Ultimately, both figures display the pattern of system inertia that mostly coincides with load levels. Inertia at low load levels becomes a challenge for providing frequency response in case of a frequency excursion.

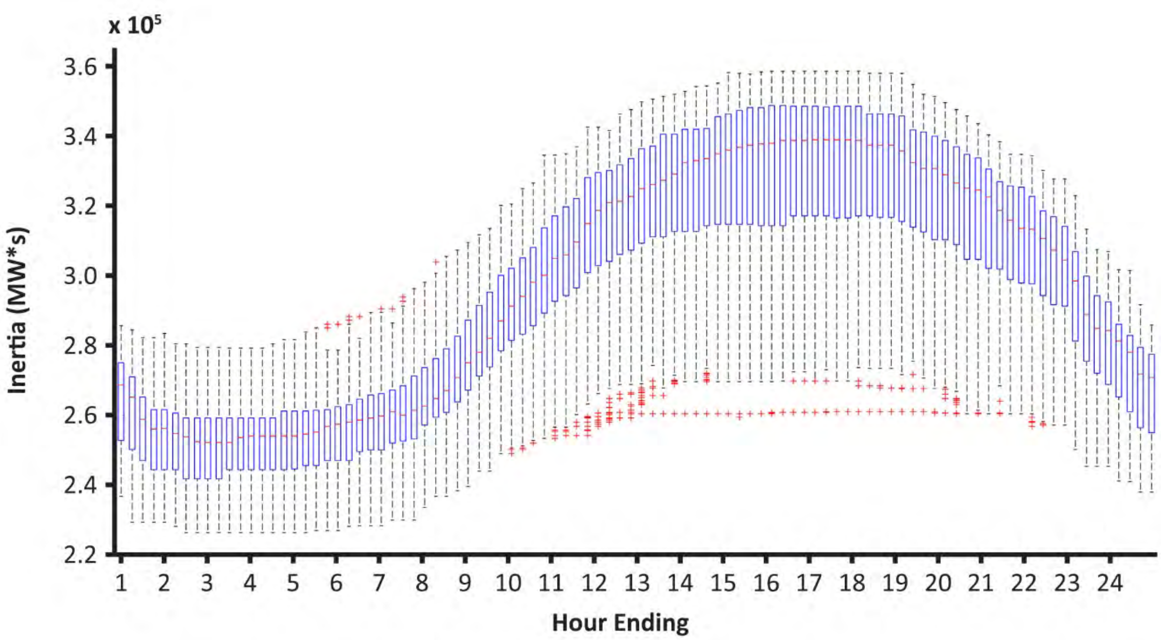


Figure 3.4: ERCOT Inertia by 15-minute Interval of Day (June 1–July 15 2016)

Eastern Interconnection

The Eastern Interconnection (EI) has significant levels of synchronous generation that allow sufficient contributions of inertia as shown in **Figure 3.5** below. The figure shows the total interconnection inertia contributions following changes to load levels. Based on the availability of data, system level monitoring of inertia and thus potential frequency response can be evaluated.

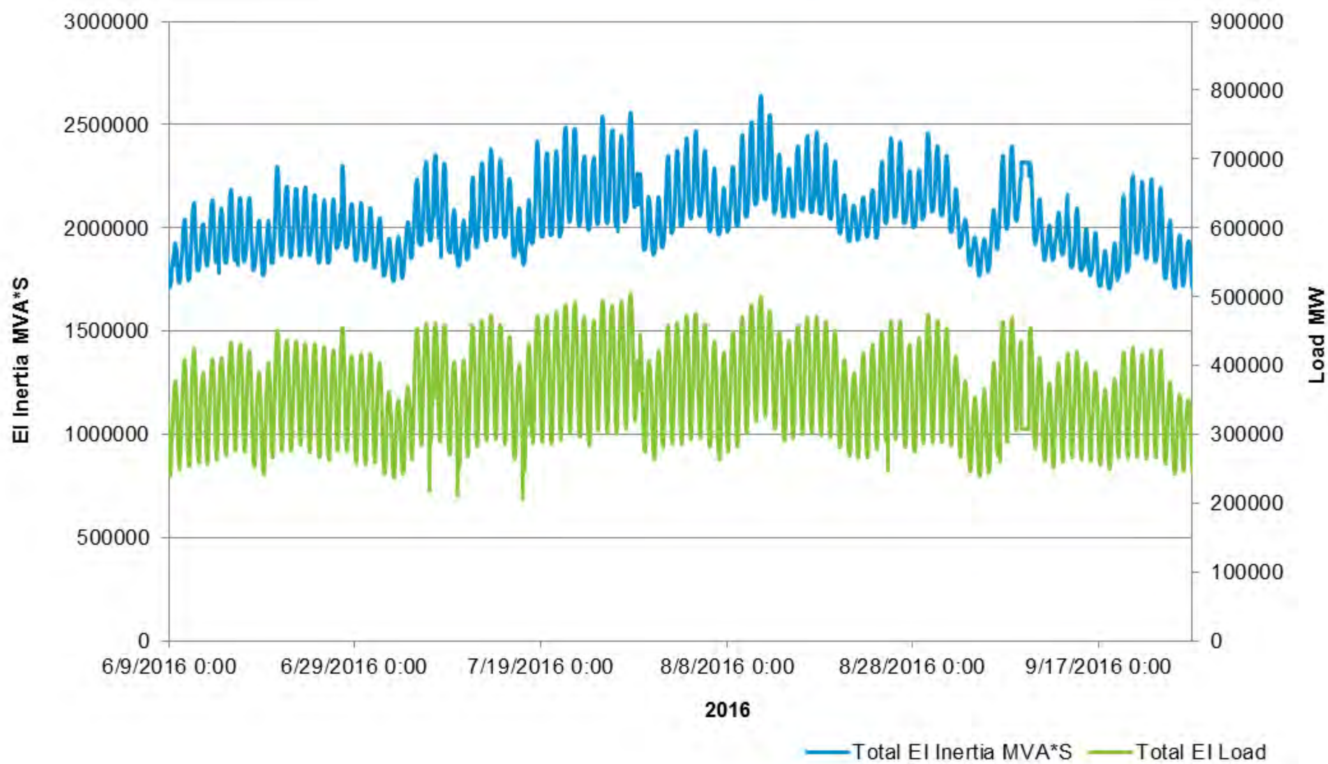


Figure 3.5: Eastern Interconnection System Inertia

Primary Frequency Response Analysis

PFR, as shown in **Figure 3.1**, has been identified by NERC's Operating Committee and Planning Committee as an ERS that will be affected by the changing grid characteristics of the North American BPS. The changing grid will be characterized by an increased penetration of new technology resources and the retirement of conventional generating resources.

NERC is studying PFRs, which relate the size of the resource lost to the resulting net change in system frequency during the period when stabilizing frequency is determined following the initiating event. To study the changing characteristics and PFR performance of the grid, NERC will use power system computer planning models. These planning models will be used to develop scenarios of the future system that will be studied to gain a detailed understanding of various factors affecting PFRs and the resulting under-frequency load shedding (UFLS) system operation. UFLS systems are designed as a backstop to prevent such events from cascading across the BPS. Primary frequency controls are deemed adequate if, following the sudden loss of the largest generator, the primary frequency control response provided by on-line resources successfully arrests and stabilizes frequency decline. This should be prior to initiating any UFLS action to arrest further frequency decline by dropping firm customer loads.[36]

[36] Largest generation loss is defined as largest category C (N-2) event; except for Eastern Interconnection, which uses largest event in the last 10 years.

NERC will perform various analyses to study the effect of replacing conventional generation with increased penetrations of new technology resources. These analyses will determine how various future scenarios of NTR plant additions and Clean Power Plan (CPP) retirements impact the system PFR. With understanding from these analyses, NERC will develop an objective basis for understanding the reliability implications of varying levels of integration and penetrations of NTRs on PFR. This study therefore has three major purposes:

- Understand the interconnection-wide reliability implications of the changing resource mix on frequency response.
- Evaluate policy issues, such as the CPP implementation, with sensitivities of the changing resource mix, control strategies, and other assumptions.
- Support future proposals for rule making.

The final report will be an assessment of the reliability risks and it will recommend technical guidance to mitigate risks of encountering system conditions that will result in UFLS protective actions. This report will document the results of the PFR evaluations, provide a firm basis for future system reliability risk determinations, and identify potential solutions that will assure a continuation of an adequate level of frequency response is maintained for the reliable operation of the BPS using conventional and new technology resources.

This frequency response study will be completed in three phases over approximately three years.

1. Phase I will study PFR for the EI by using detailed frequency modeling for existing and future plants with a load modeled by the ZIP Load Model. The ZIP Load model is characterized by coefficients of a load model comprised of constant impedance (Z), constant current (I), and constant power loads (P).
2. Phase II will study PFR for the EI by using detailed frequency modeling for existing and future plants with load modeled by a complex load model (CLM). The CLM model will replace the constant MVA, current, and impedance load with a composition of loads consisting of large and small induction motors, discharge lighting, constant MVA load, and a static load response.
3. Phase III will study PFR for the Eastern Interconnection, ERCOT, and the Western Electricity Coordinating Council by using detailed frequency modeling for existing and future plants, loads modeled by a CLM model, DER modeling, and energy storage modeling.

Net Load Ramping

Changes in the amount of nondispatchable resources, transmission system constraints, load behaviors, and resource mix can impact the ramp rates needed to keep the system load and generation in balance. Most areas that have wide-scale integration of DERs may experience planning or operational issues due to large load ramps. For example, solar photovoltaic (PV) is heavily integrated into the electric system in California ISO (CAISO), and operators there are faced with multi-hour ramps during the evening hours partly coinciding with sunset. Hence, CAISO must ensure that enough system ramping capability is available to follow the fast net load fluctuations.

With the increasing penetration of generation resources for which the BA may have limited ability to control the level of output, consideration of system ramping capability becomes an even more important component of planning and operations. CAISO has been experiencing challenges with ramping inter- and intra- hour; these challenges were studied and presented through the duck curve,[37] shown below in **Figure 3.6**. On May 15, 2016, actual net-load dropped to 11,663 MW from the projected 2016 load of just over 15,000 MW, which is four years ahead of the original "duck curve" estimate. Thus CAISO is experiencing the issues with ramping in advance of the previously predicted time frame.

[37] CAISO - Flexible Resources to Help Renewable - Fast Facts

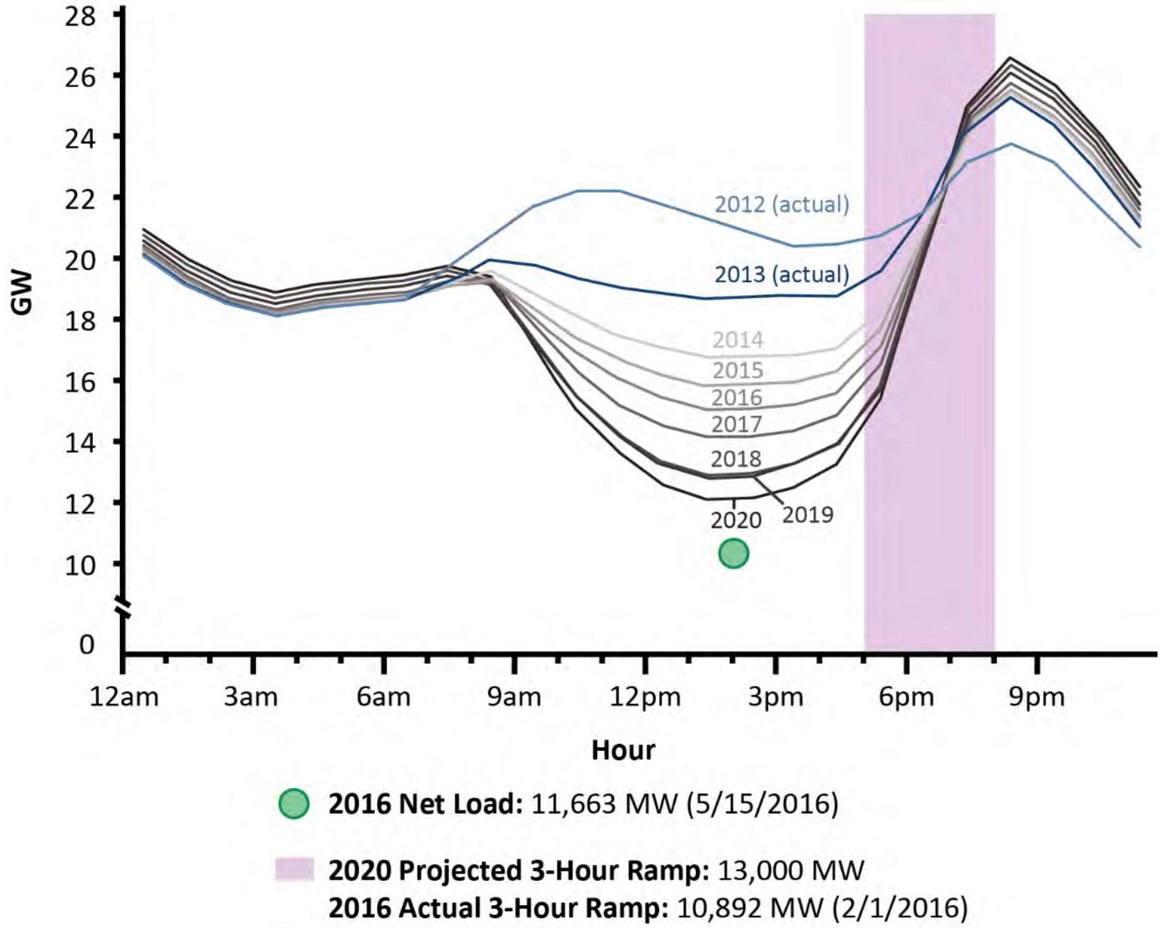
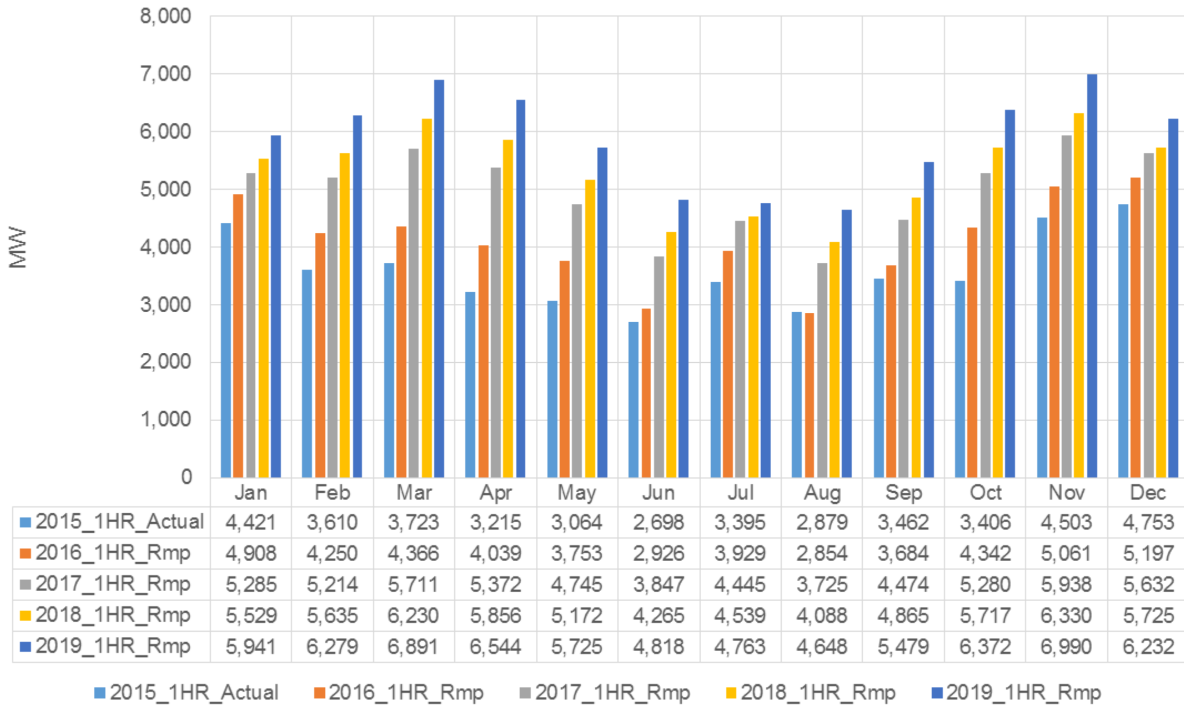


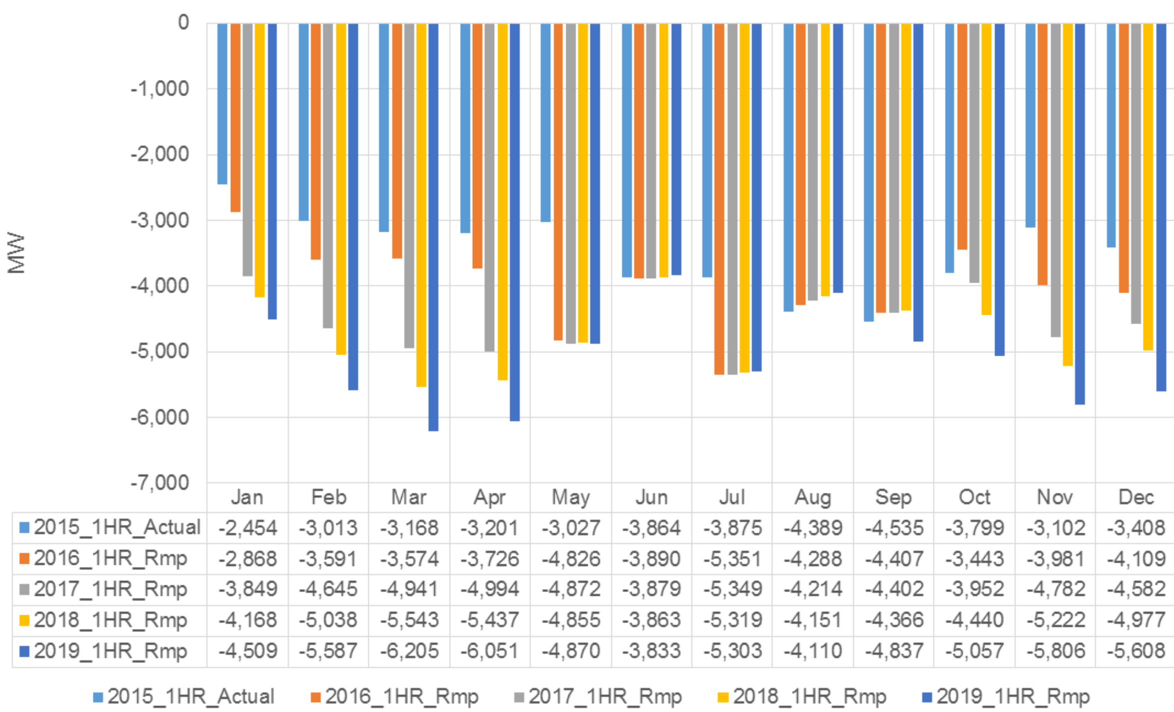
Figure 3.6: Analysis of CAISO Duck Curve

Based on the experience with net load ramping, CAISO projects the future ramps to be higher than previously projected. Below are the projections for CAISO's ramping from 2015 actual ramps to 2019 projected one-hour upward and downward ramps, shown in **Figure 3.7** and in **Figure 3.8** respectively. The three-hour upward and downward ramp projections are shown in **Figure 3.9** and **Figure 3.10** respectively.



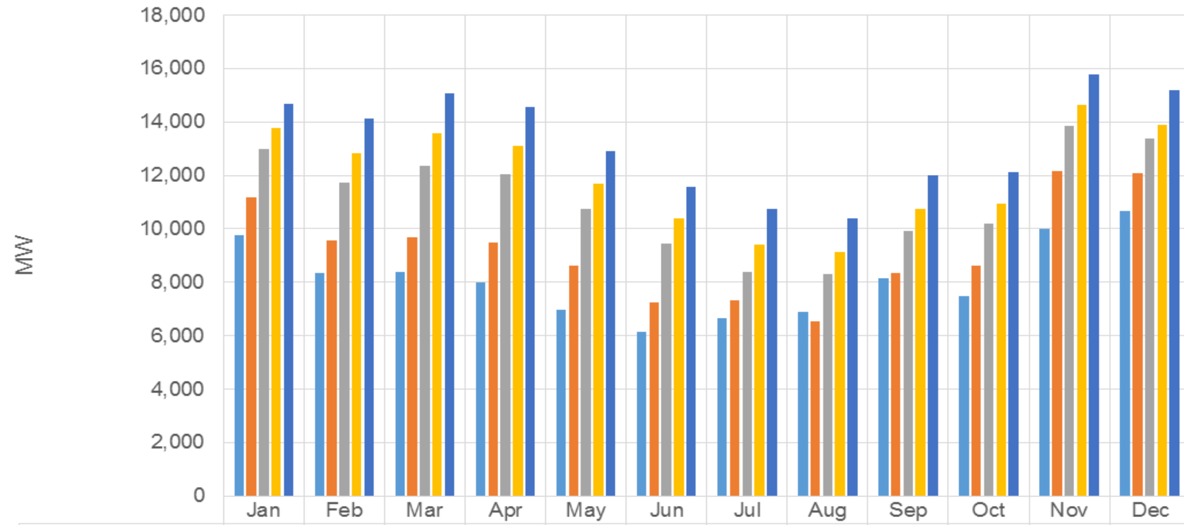
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_1HR_Actual	4,421	3,610	3,723	3,215	3,064	2,698	3,395	2,879	3,462	3,406	4,503	4,753
2016_1HR_Rmp	4,908	4,250	4,366	4,039	3,753	2,926	3,929	2,854	3,684	4,342	5,061	5,197
2017_1HR_Rmp	5,285	5,214	5,711	5,372	4,745	3,847	4,445	3,725	4,474	5,280	5,938	5,632
2018_1HR_Rmp	5,529	5,635	6,230	5,856	5,172	4,265	4,539	4,088	4,865	5,717	6,330	5,725
2019_1HR_Rmp	5,941	6,279	6,891	6,544	5,725	4,818	4,763	4,648	5,479	6,372	6,990	6,232

Figure 3.7: CAISO 2015–2019 Monthly One-Hour Upward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_1HR_Actual	-2,454	-3,013	-3,168	-3,201	-3,027	-3,864	-3,875	-4,389	-4,535	-3,799	-3,102	-3,408
2016_1HR_Rmp	-2,868	-3,591	-3,574	-3,726	-4,826	-3,890	-5,351	-4,288	-4,407	-3,443	-3,981	-4,109
2017_1HR_Rmp	-3,849	-4,645	-4,941	-4,994	-4,872	-3,879	-5,349	-4,214	-4,402	-3,952	-4,782	-4,582
2018_1HR_Rmp	-4,168	-5,038	-5,543	-5,437	-4,855	-3,863	-5,319	-4,151	-4,366	-4,440	-5,222	-4,977
2019_1HR_Rmp	-4,509	-5,587	-6,205	-6,051	-4,870	-3,833	-5,303	-4,110	-4,837	-5,057	-5,806	-5,608

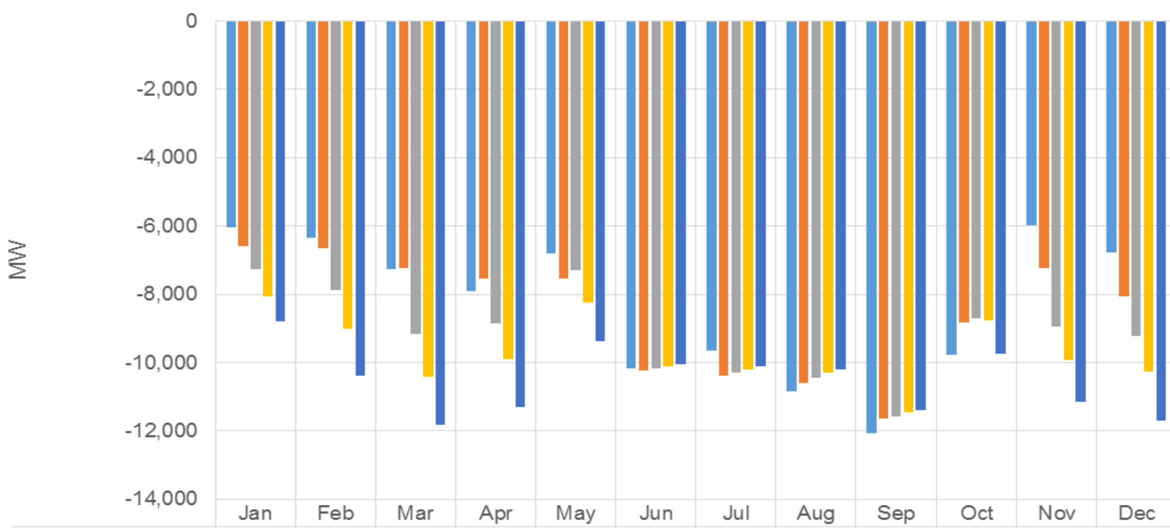
Figure 3.8: CAISO 2015–2019 Monthly One-Hour Downward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_3HR_Actual	9,775	8,366	8,367	8,001	6,962	6,153	6,672	6,882	8,158	7,469	9,987	10,684
2016_3HR_Rmp	11,191	9,578	9,700	9,484	8,629	7,262	7,335	6,540	8,353	8,640	12,155	12,096
2017_3HR_Rmp	12,970	11,729	12,364	12,054	10,737	9,464	8,397	8,295	9,918	10,196	13,835	13,399
2018_3HR_Rmp	13,758	12,846	13,596	13,117	11,672	10,383	9,402	9,123	10,728	10,939	14,636	13,896
2019_3HR_Rmp	14,691	14,114	15,067	14,543	12,904	11,571	10,750	10,407	12,003	12,121	15,781	15,186

2015_3HR_Actual 2016_3HR_Rmp 2017_3HR_Rmp 2018_3HR_Rmp 2019_3HR_Rmp

Figure 3.9: CAISO 2015–2019 Monthly Three-Hour Upward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_3HR_Actual	-6,033	-6,353	-7,276	-7,903	-6,795	-10,179	-9,658	-10,837	-12,059	-9,756	-5,974	-6,766
2016_3HR_Rmp	-6,578	-6,652	-7,217	-7,549	-7,525	-10,224	-10,375	-10,606	-11,652	-8,834	-7,245	-8,067
2017_3HR_Rmp	-7,277	-7,882	-9,162	-8,842	-7,284	-10,166	-10,288	-10,442	-11,571	-8,712	-8,958	-9,224
2018_3HR_Rmp	-8,065	-9,003	-10,424	-9,901	-8,237	-10,110	-10,185	-10,301	-11,455	-8,767	-9,928	-10,270
2019_3HR_Rmp	-8,803	-10,375	-11,822	-11,292	-9,384	-10,043	-10,110	-10,212	-11,392	-9,730	-11,152	-11,690

2015_3HR_Actual 2016_3HR_Rmp 2017_3HR_Rmp 2018_3HR_Rmp 2019_3HR_Rmp

Figure 3.10: CAISO 2015–2019 Monthly Three-Hour Downward Ramps

ERCOT's Resource Flexibility Analysis Method

EPRI has created several flexibility metrics that can be helpful for performing ramping analysis. One metric is periods of flexibility deficit, which is a count of the number of intervals in the study period where net flexibility is below zero. Periods of flexibility deficit is calculated for a specific time horizon as well as for ramp direction. Another metric is expected unserved ramp, which is the total magnitude of negative net flexibility.

ERCOT is using the methodology for performing this analysis. The methodology assumes that the study period is a full year and the time resolution is five minutes, but it can be modified to accommodate different study periods and time resolutions.

The first step in performing the flexibility study for a future year is to prepare a generator database of all generators that will be active in the study year; this includes existing generators that are not scheduled to retire before the study year as well as planned generators that are scheduled to be on-line during the study year.

The next step is to obtain hourly profiles for wind, solar, and load for the study year, and then interpolate these profiles into a higher resolution.

The hourly wind, solar, and load profiles are used as inputs into a production cost simulation tool along with the generator database prepared earlier. Any resources with fixed schedules or must-run units should be modeled as such in the production cost simulation. ERCOT uses Energy Exemplar's Plexos to perform 365 daily optimization runs with a one-day look ahead in order to obtain unit commitments for the entire study year.

Each unit's commitment status must be found for each hour of the year from the hourly production cost simulation run, and the temporal resolution of the hourly wind, solar, and load profiles must be increased to a five-minute resolution. Once this is due, a sequential production cost simulation should be performed in order to obtain each unit's five-minute dispatch for the study year to serve the given net load. Again, in this dispatch run, capacity reserved for provision of the AS is not available for dispatch except for nonspinning reserves that are generally available in ERCOT in energy scarcity situations. This dispatch data, along with the generator database and the five-minute load data, are the inputs to EPRI's InFLEXion tool. The InFLEXion tool can perform all of the analysis described in this document as well as additional ramping/flexibility analyses.

ERCOT's Sample results

Figure 3.11 below shows the average one-hour net load ramps for each hour of each day in the same time period. Negative numbers in this figure represent hours where the average net load ramp was in the downward direction rather than upward.

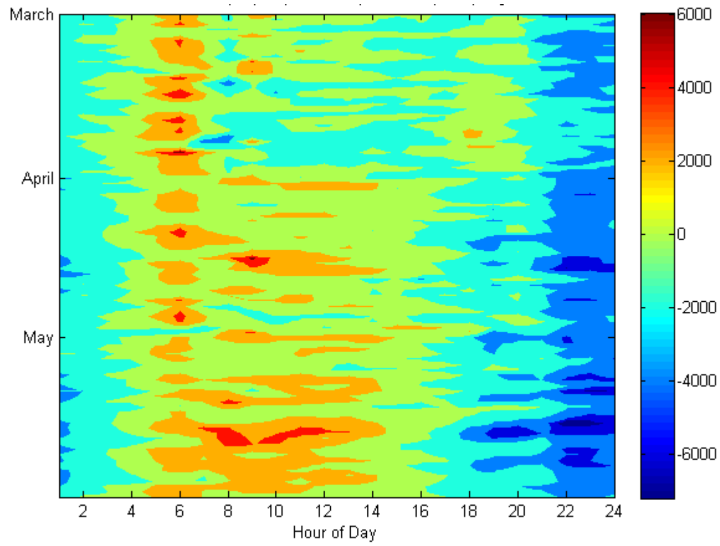


Figure 3.11: ERCOT's Net Load One Hour Ramps for Spring 2017

The heat map **Figure 3.11** shows the pattern of upward or downward ramps for the spring of 2017 by the hour of the day. The pattern forecasts ramps to occur during the early morning and at late night.

In addition to calculating the ramp up, ERCOT forecasted available flexibility resources that can be used to meet the ramps. **Figure 3.12** below shows the average amount of available upward flexibility that can be provided by the resource fleet to serve one-hour net load ramps for each hour of each day in the spring of 2017. The available flexibility is calculated based on what units are on-line and able to increase generation from their current operation point (as obtained from production cost simulation) as well as units that are off-line but could start up quickly enough to help serve the ramp (if necessary), including off-line nonspinning reserves. Note that in this level of analysis, all reserves are considered available to follow expected net load ramps

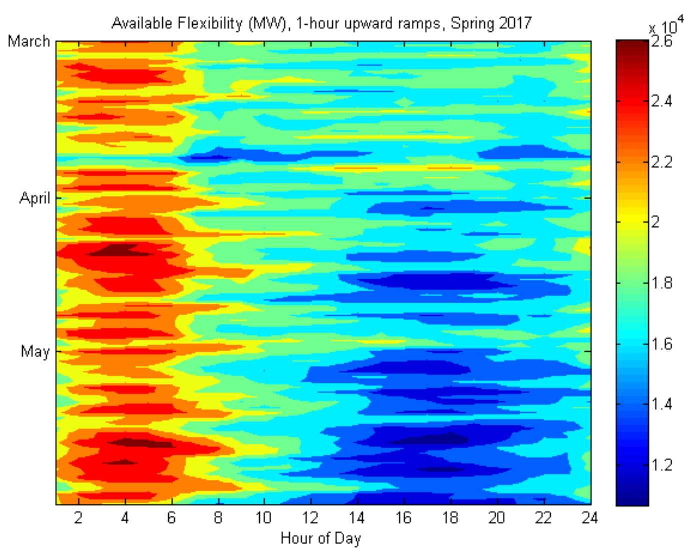


Figure 3.12: ERCOT's Available Flexibility for One Hour Ramps in Spring 2017

ERCOT is currently working on improving unit commitments to include the tradeoff between using coal and natural gas fuels. The PLEXUS tool is optimal for plant startup and run times, but it doesn't consider human behavior as well as shortened or prolonged maintenance schedules. In addition, EPRI is considering improving the process for their InFLEXion tool to include transmission constraints.

Hourly CPS1 Evaluation on Interconnection Basis

For areas where ramping is not a significant challenge, there needs to be a different method of evaluating whether that area is or would be experiencing ramping-related challenges. Historical Control Performance Standard (CPS) hourly data can be an indication of potential ramping issues. A BA can evaluate its historical ramps against its real-time control performance standard (CPS1)[38] to determine whether it is beginning to experience ramping problems. This can be accomplished by evaluating hourly CPS performance data for trends, such as CPS1 scores less than 100 percent for certain hours of the day and certain months of the year. It should be noted that this evaluation of CPS1 on an hourly basis does not imply any NERC standards requirements; this is simply a methodology for evaluating ramping needs of a given area.

Figure 3.13 below shows the CPS1 score exceedances by BA on an hourly basis for the Eastern Interconnection (EI). The bottom graph (Grey) shows the availability of CPS1 data from the BA, the middle graph (Red) shows number of hourly CPS1 exceedances for three or more consecutive hours, and the top graph (Black) shows the number of hourly CPS1 exceedances. The last column, which is highlighted in a blue box, represents the total score of hourly CPS1 for EI in each respective area.

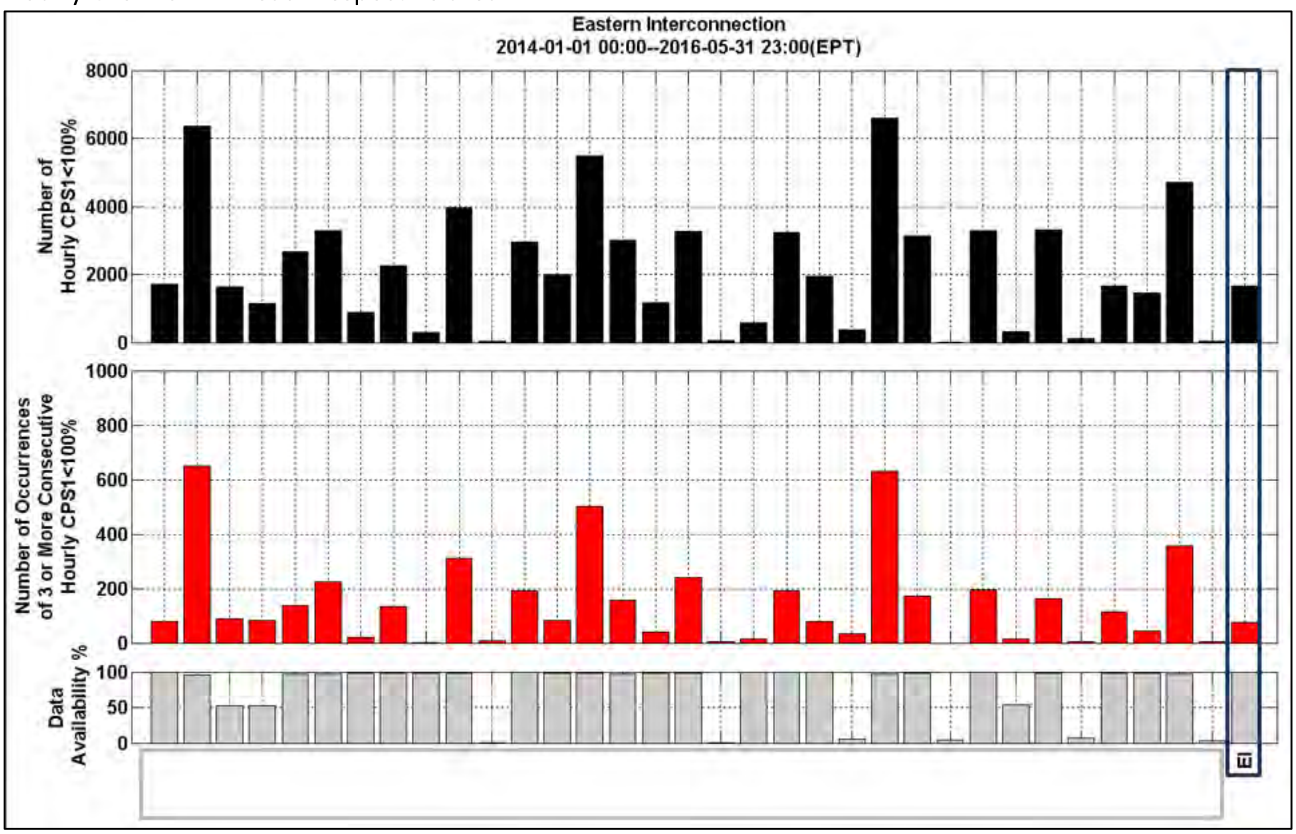


Figure 3.13: Eastern Interconnection—CPS1 exceedance counts per BA on an hourly basis

[38] CPS1 is a statistical measure of a BA's area control error (ACE) variability in combination with the interconnection frequency error from scheduled frequency. It measures the covariance between the ACE of a BA and the frequency deviation of the interconnection, which is equal to the sum of the ACEs of all of the BAs. CPS1 assigns each BA a share of the responsibility for controlling the interconnection's steady-state frequency. The CPS1 score is reported to NERC on a monthly basis and averaged over a 12-month moving window. A violation of CPS1 occurs whenever a BA's CPS1 score for the 12-month moving window falls below 100 percent.

Similarly, **Figure 3.14** shows the CPS1 exceedances for Western Interconnection (WI). Note that the WI chart does not include BA's that use variable bias settings to calculate their ACE.

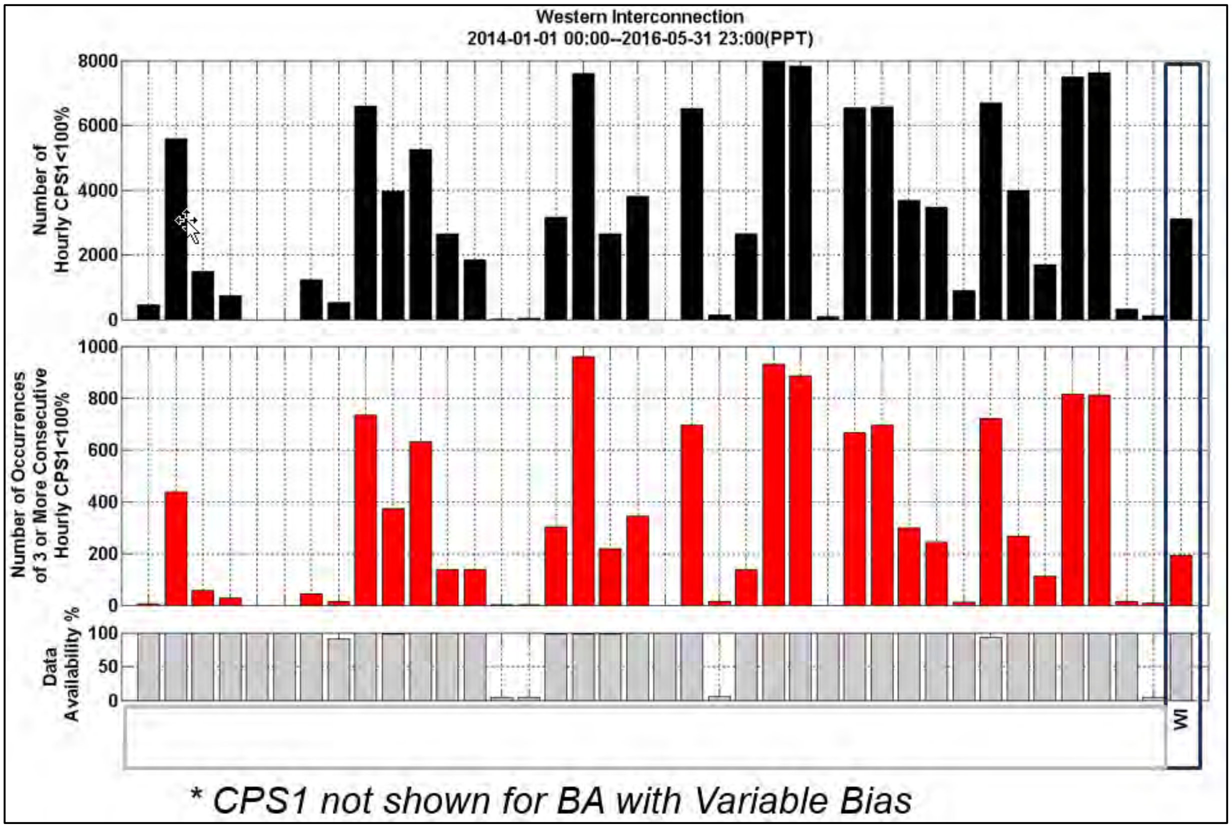


Figure 3.14: Western Interconnection—CPS1 exceedance counts per BA on an hourly basis[39]

Several assessment areas, including MISO, Manitoba Hydro, and NPCC-Maritimes, evaluated their respective area for ramping-related challenges. From their results, the ramping measure continues to be monitored, but does not currently pose a challenge to reliability.

[39] Balancing Authorities unnamed to maintain confidentiality.

Distributed Energy Resources

An increasing quantity of DERs are being installed behind-the-meter and they may or may not be known assets on the distribution system. **Figure 3.15** shows the cumulative installations of nonutility scale solar generation in the U.S. from 2010–2015. Additional installations are forecasted to 2021.[40] Behind-the-meter generation units essentially means that, despite some knowledge of how much potential capacity is installed, there is no individual metering of these units that would indicate their actual energy produced during any time frame. Including generation from these units and the real demand of the system results in a netted system load that can complicate system operations. In low penetrations of DERs to local system load, there is much less potential for any issues to be escalated into the BPS. The potential for issues to impact the BPS grows in some relation with increased DER penetration levels. Both the potential issues to system reliability and the changing characteristics of the load due to increasing DER installations must be studied further.

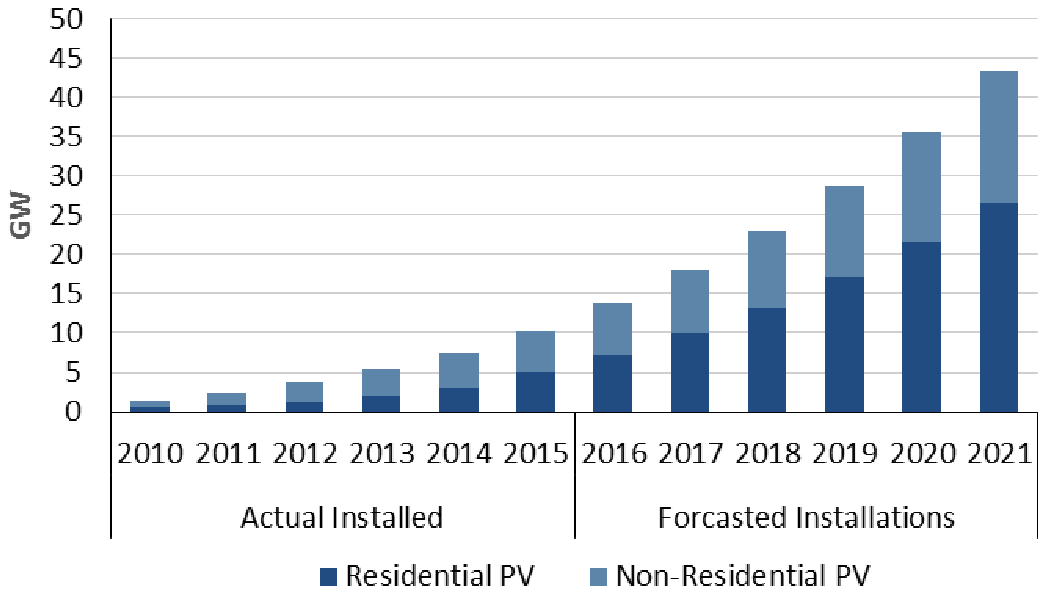


Figure 3.15: Cumulative Installations of Non-Utility Photovoltaic

Historical data sets enable characterization and trending of key performance metrics, including factors that contribute to resource availability and adequacy. DERs, such as rooftop solar, do not have long-term historical data sets, and this lack of data limits the understanding of the long-term implications of DER performance. The potential output levels of DERs show a large degree of variance over a vast geographic scale, so the ideal type and capacity contributions of DER generation will differ by region. Several studies for capacity value calculations, however, differ in results due to differences in DERs and load characteristics in the regions under study.

Calculating capacity values for existing DERs requires chronological generation data that are synchronized with load data and other relevant system properties. Existing power system data bases can be used to track this data, which would be useful in helping to better understand DER performance and operational issues. However, consistent and accurate methods are needed to calculate capacity credits (sometimes called capacity values) attributable to DERs. Defining a compendium of "best practices" for evaluating DER contribution to resource adequacy would assist in providing some alignment of these different methods.

Data and information exchange across the transmission and distribution interface is a crucial aspect of power system planning, forecasting, and DER modeling. Both transmission and distribution entities should develop a

[40] GTM Research: Solar Market Insight Report 2016 Q2

common framework where this type of data exchange can be facilitated to ensure the reliability of the BPS. In addition, adequate operator observability and controllability of the BPS will require access to information and data concerning existing and planned DERs. System planners, both transmission and distribution, should be assessing the penetration of large amounts of DERs that may require changes to forecasting, dispatch, and control of the bulk power system. In states where policies haven't yet incentivized the installation of DERs, policy makers should consider the potential reliability threats and incorporate system upgrades into future policy decisions. State policy makers should leverage the experience in California, New York, other states and provinces that continue to refine their respective policies for accommodating high levels of distributed generation in a reliable manner.

Diminishing On-Peak Impact of DER

At a certain penetration level of distributed or behind-the-meter energy resources, additional installations of photovoltaic (PV) resources have a diminished impact on peak load. This is mainly due to these resources being considered passive load modifiers rather than dispatchable resources, thus netting their generated energy in with the load. A generic summer-peaking system was modeled to study the impacts of increasing DERs; this result is depicted in **Figure 3.16**, which shows that increased solar penetration can shift the critical hours to later in the day with a largely coincident summer-peaking load profile. Due to lower solar irradiances in late hours of the day, the more solar added to the system, the less significant it becomes at peak demand. This affects the timing of reliability in critical hours and decreases the capacity contributions that can be expected to serve load during critical hours. **Figure 3.16** shows net load has been shifted 2–3 hours at high levels of solar penetration (i.e., from 10 percent to 50 percent solar).

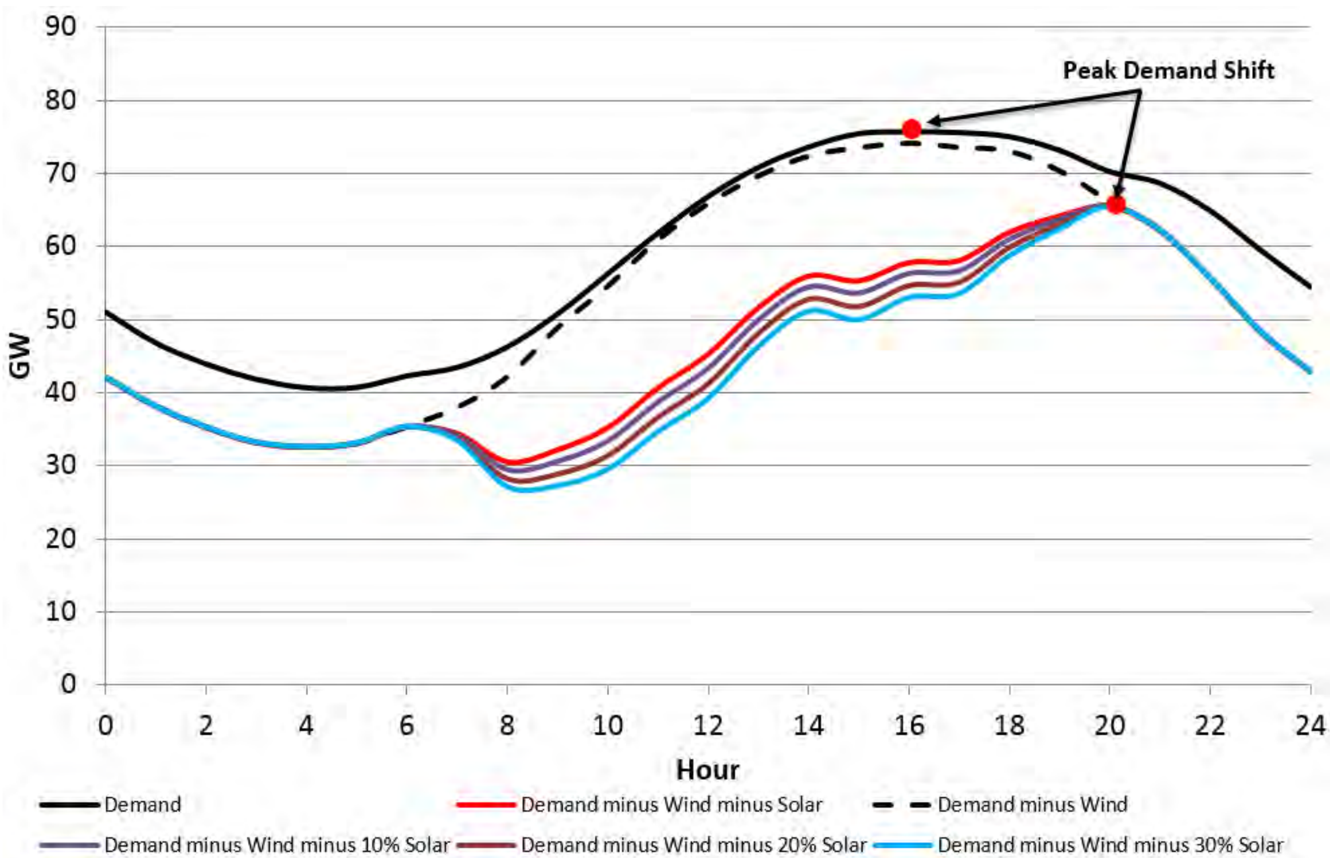


Figure 3.16: Demand and Net Demand Shapes at Different DER Penetration Levels

Furthermore, **Figure 3.17** shows that solar capacity factors reach near-zero levels as solar penetration increases. This ultimately supports the results of this system analysis whereby net load is shifted 2–3 hours due to capacity factors reaching near-zero levels and as solar energy radiation in the evening is negligible.

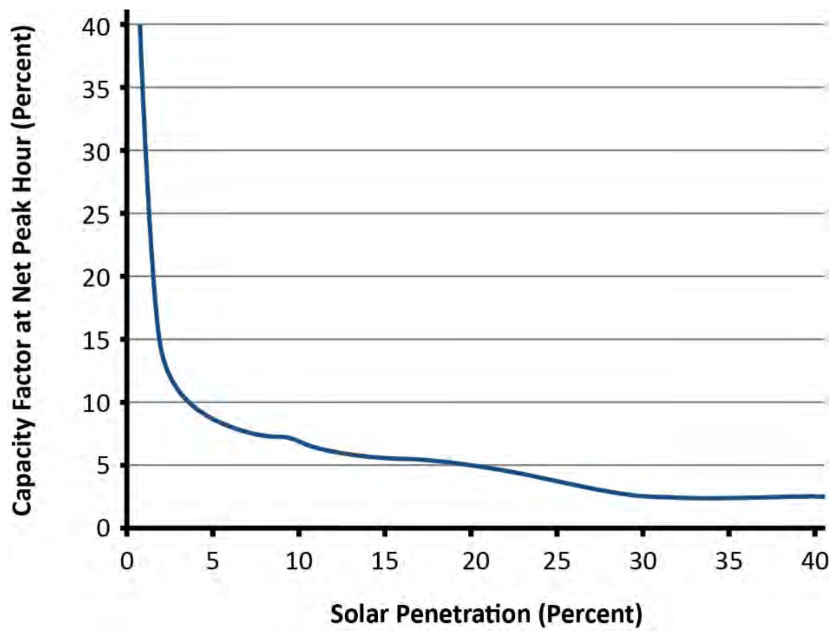


Figure 3.17: Solar Power Capacity Factor

Distributed Energy Resources Task Force

The Distributed Energy Resources Task Force (DERTF) was established in response to a recommendation of the *Essential Reliability Services Task Force* (ERSTF) *Measures Framework Report*.[41] This task force will develop a report by Q1 of 2017 that will examine existing practices for incorporating DERs in to planning models and studies, identify operational impacts to the BPS, and review existing NERC standards to ensure that DERs can be integrated reliably into the BPS. The report will also explore existing policies oriented to support the reliable integration of DERs on the BPS and further examine the interplay with other ERSs. In developing this report, the task force will review the NERC Functional Model, existing NERC Reliability Standards, and coordinate with Electrical and Electronics Engineers (IEEE) 1547 related efforts. Additionally, the task force will review definitions for behind-the-meter generation, distributed generation, and other related terms to provide clear distinctions between each category.

[41] NERC Essential Reliability Services Task Force Measures Framework Report; November 2015

Chapter 4: Reliability Assessment Trends and Analysis

This section provides an overview of the key projections collected and analyzed for this assessment, including reserve margins, demand and energy, demand-side management (DSM), generation fuel mix, and transmission adequacy. These data and resulting analyses are crucial components in the assessment and identification of the reliability issues in focus.

Reserve Margins

Understanding the relation between changes to an area's demand needs, and available generating capacity is traditionally performed through a planning reserve margin analysis. Generally, this analysis compares the forecasted peak load to the amount of capacity that could be considered available to serve peak load. Included in these values are considerations for passive or controllable peak load reduction programs, also referred to as DSM. When compared to an individual area's target reserve margin level (or Reference Margin Level), this deterministic-based calculation provides a straightforward viewpoint on the adequacy of a system's resources for all ten years of the assessment.

Both an Anticipated Reserve Margin and Prospective Reserve Margin are calculated using a deterministic reserve margin analysis, essentially providing two different benchmarks for varying degrees of certainty in future generation. More details on the components to both of these reserve margin calculations can be found in Appendix II. **Table 4.1**,[42] **Table 4.2**, and **Table 4.3** below show the overall demand, resources, and planning reserve margins for Years 1, 5, and 10 of the assessment period for all assessment areas and interconnection subtotals.

Table 4.1: Peak Season 2017(S) / 2017–2018(W): Projected Demand, Resources, & Planning Reserve Margins

Assessment Area/ Interconnection	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	
FRCC	48,125	45,111	55,015	55,436	21.95%	22.89%	15.00%
MISO	127,641	121,814	143,844	150,779	18.09%	23.78%	15.20%
MRO-Manitoba Hydro*	4,826	4,826	5,419	5,526	12.29%	14.51%	12.00%
MRO-SaskPower*	3,724	3,639	4,303	4,303	18.24%	18.24%	11.00%
NPCC-Maritimes*	5,584	5,312	6,716	6,735	26.42%	26.79%	20.00%
NPCC-New England	26,698	25,857	31,112	31,313	20.32%	21.10%	16.74%
NPCC-New York	33,363	32,115	39,613	40,382	23.35%	25.74%	15.00%
NPCC-Ontario	22,680	22,000	26,822	26,822	21.92%	21.92%	18.13%
NPCC-Québec*	38,150	35,982	41,217	42,317	14.55%	17.61%	12.20%
PJM	154,149	145,266	190,456	194,577	31.11%	33.95%	16.50%
SERC-E	43,213	42,558	51,175	51,722	20.25%	21.53%	15.00%
SERC-N	42,540	40,751	48,910	51,265	20.02%	25.80%	15.00%
SERC-SE	47,762	45,534	60,062	60,596	31.91%	33.08%	15.00%
SPP	51,936	51,184	65,083	65,004	27.16%	27.00%	12.00%
Texas RE-ERCOT	71,416	68,548	80,510	85,050	17.45%	24.07%	13.75%
WECC-AB*	-	-	-	-	33.56%	43.44%	11.03%
WECC-BC*	-	-	-	-	12.39%	12.39%	12.10%
WECC-CAMX	54,774	53,027	63,765	63,859	20.25%	20.43%	16.16%
WECC-NWPP-US	50,013	48,794	62,374	62,568	27.83%	28.23%	16.32%
WECC-RMRG	12,392	11,847	15,364	15,364	29.68%	29.68%	14.14%
WECC-SRSG	23,207	22,787	29,094	29,095	27.68%	27.68%	15.82%

[42] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Eastern Interconnection	612,242	585,967	728,531	744,461	24.33%	27.05%	-
Québec Interconnection	38,150	35,982	41,217	42,317	14.55%	17.61%	12.20%
ERCOT Interconnection	71,416	68,548	80,510	85,050	17.45%	24.07%	13.75%
Western Interconnection	155,147	151,216	189,941	191,194	25.61%	26.44%	15.37%
TOTAL-NERC	876,955	841,713	1,040,199	1,063,021	23.58%	26.29%	-

*Winter Peaking System

Table 4.2: Peak Season 2021(S) / 2021–2022(W): Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	
FRCC	50,461	47,256	58,379	59,445	23.54%	25.79%	15.00%
MISO	130,728	124,901	144,850	157,590	15.97%	26.17%	15.20%
MRO-Manitoba Hydro*	4,685	4,685	6,412	5,844	36.86%	24.74%	12.00%
MRO-SaskPower*	3,901	3,816	4,872	4,950	27.67%	29.71%	11.00%
NPCC-Maritimes*	5,622	5,350	6,661	6,735	24.49%	25.89%	20.00%
NPCC-New England	26,816	26,438	31,330	32,516	18.50%	22.99%	15.93%
NPCC-New York	33,555	32,307	40,727	43,474	26.06%	34.56%	15.00%
NPCC-Ontario	22,479	21,878	26,235	26,290	19.92%	20.17%	17.00%
NPCC-Québec*	39,415	37,097	42,746	43,846	15.23%	18.19%	12.70%
PJM	157,358	153,934	197,178	234,816	28.09%	52.54%	16.50%
SERC-E	46,126	45,454	54,798	55,345	20.56%	21.76%	15.00%
SERC-N	43,800	42,105	50,177	52,460	19.17%	24.59%	15.00%
SERC-SE	49,325	47,065	62,126	62,669	32.00%	33.16%	15.00%
SPP	53,779	52,868	64,046	64,775	21.14%	22.52%	12.00%
Texas RE-ERCOT	74,966	72,098	86,522	102,281	20.01%	41.86%	13.75%
WECC-AB*	13,198	13,198	16,439	19,902	24.56%	50.80%	11.03%
WECC-BC*	12,242	12,242	13,757	13,757	12.38%	12.38%	12.10%
WECC-CAMX	54,162	52,455	63,626	63,827	21.30%	21.68%	16.16%
WECC-NWPP-US	51,693	50,498	64,879	65,288	28.48%	29.29%	16.32%
WECC-RMRG	13,194	12,585	15,230	15,159	21.02%	20.45%	14.14%
WECC-SRSG	24,978	24,623	29,182	29,346	18.52%	19.18%	15.82%
Eastern Interconnection	628,635	608,057	747,790	806,910	22.98%	32.70%	-
Québec Interconnection	39,415	37,097	42,746	43,846	15.23%	18.19%	12.70%
ERCOT Interconnection	74,966	72,098	86,522	102,281	20.01%	41.86%	13.75%
Western Interconnection	160,616	156,750	193,574	197,160	23.49%	25.78%	15.37%
TOTAL-NERC	903,632	874,003	1,070,632	1,150,197	22.50%	31.60%	-

*Winter Peaking System

Table 4.3: Peak Season 2026(S) / 2026–2027(W): Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	
FRCC	52,803	49,499	60,976	62,978	23.19%	27.23%	15.00%
MISO	134,462	128,635	140,297	153,047	9.07%	18.98%	15.20%
MRO-Manitoba Hydro*	4,821	4,821	6,412	5,969	33.00%	23.82%	12.00%
MRO-SaskPower*	4,159	4,074	5,152	5,327	26.46%	30.75%	11.00%
NPCC-Maritimes*	5,518	5,248	6,655	6,724	26.81%	28.13%	20.00%
NPCC-New England	27,218	26,841	31,353	32,539	16.81%	21.23%	15.93%
NPCC-New York	34,056	32,808	40,727	43,474	24.14%	32.51%	15.00%
NPCC-Ontario	22,265	21,056	24,646	24,837	17.05%	17.96%	16.00%
NPCC-Québec*	40,625	38,307	42,746	43,846	11.59%	14.46%	12.70%
PJM	161,891	158,367	197,178	235,353	24.51%	48.61%	16.50%
SERC-E	49,309	48,625	58,863	59,410	21.06%	22.18%	15.00%
SERC-N	45,690	44,146	53,247	55,530	20.62%	25.79%	15.00%
SERC-SE	52,083	49,810	62,636	63,179	25.75%	26.84%	15.00%
SPP	56,048	55,144	62,592	63,011	13.51%	14.27%	12.00%
Texas RE-ERCOT	78,572	75,704	86,972	102,129	14.88%	34.91%	13.75%
WECC-AB*	14,304	14,304	16,424	19,878	14.82%	38.97%	11.03%
WECC-BC*	13,040	13,040	14,316	15,306	9.79%	17.38%	12.10%
WECC-CAMX	54,005	52,298	61,639	59,898	17.86%	14.53%	16.16%
WECC-NWPP-US	53,294	52,101	65,079	65,562	24.91%	25.84%	16.32%
WECC-RMRG	14,094	13,459	16,088	16,088	19.53%	19.53%	14.14%
WECC-SRSG	27,424	27,069	31,763	31,927	17.34%	17.95%	15.82%
Eastern Interconnection	650,324	629,074	750,733	811,379	19.34%	28.98%	-
Québec Interconnection	40,625	38,307	42,746	43,846	11.59%	14.46%	12.70%
ERCOT Interconnection	78,572	75,704	86,972	102,129	14.88%	34.91%	13.75%
Western Interconnection	166,468	162,578	192,724	194,961	18.54%	19.92%	15.37%
TOTAL-NERC	935,988	905,662	1,073,175	1,152,315	18.50%	27.23%	-

*Winter Peaking System

Demand and Energy

To better understand the demand requirements of an assessment area, both the seasonal on-peak demand and annual energy requirements must be studied. NERC analyses a ten-year compounded annual growth rate (CAGR)[43] for both demand and energy using forecasted data from 1990 to the present. Both **Figure 4.1** and **Figure 4.2** below show a consistent downward trend in demand and energy forecast data. The *2016 LTRA* reference case calculates a compounded annual growth rate of 0.73 percent for summer demand, 0.72 percent for winter demand, and 0.71 percent for annual net energy.

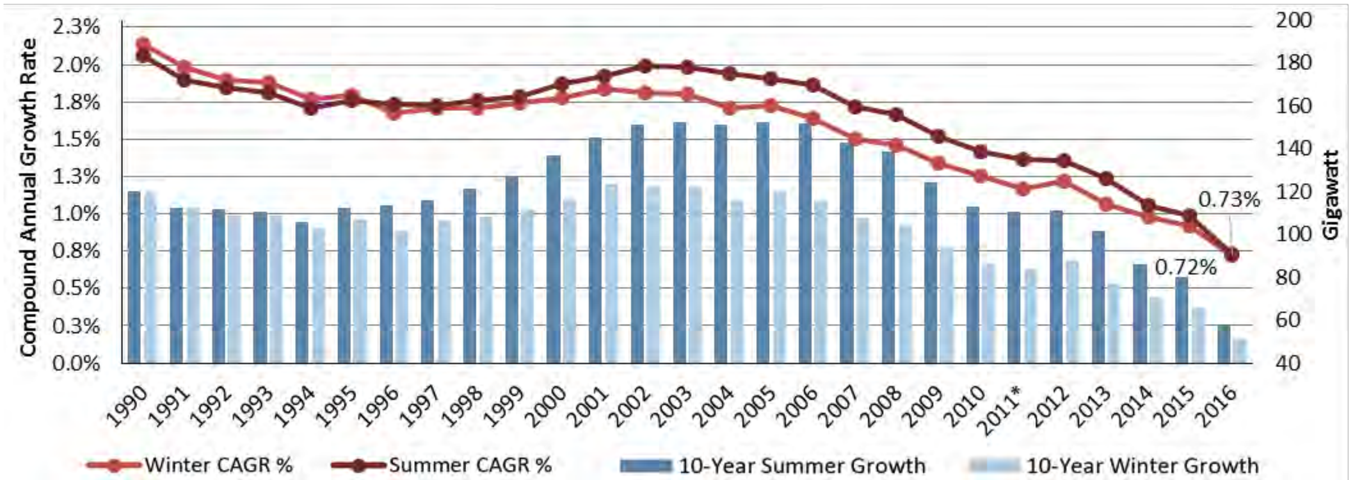


Figure 4.1: Compound Annual Growth Rate–Demand

*Prior to the *2011LTRA*, the initial year of the 10-year assessment period is the report year (e.g., the 10-year assessment period for the *1990LTRA* was 1990–1999). The *2011 LTRA* and subsequent LTRAs examine the initial year of the assessment period as one year out (e.g., the 10-year assessment period for the *2011 LTRA* is 2012–2023).

The decreasing growth rate in energy is most notably detected in 2010; this is a deviation from the nearly flat energy growth rate observed in prior years. In the last year alone, the growth rate dropped by half from 0.8 to 0.7 percent.

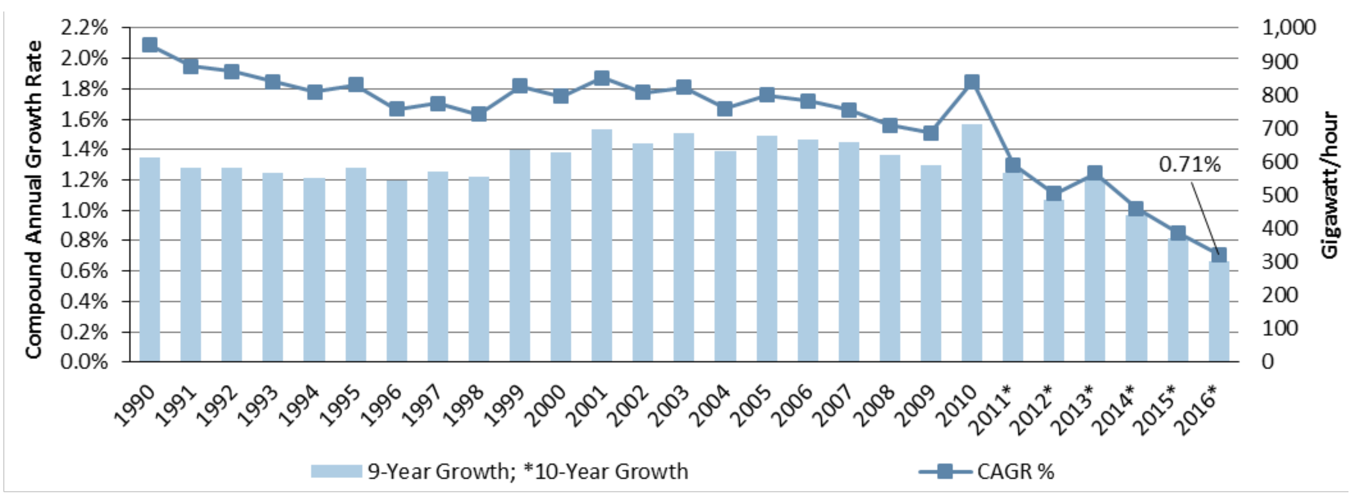


Figure 4.2: Compound Annual Growth Rate–Energy[44]

[43] Compounded annual growth rate (CAGR) provides the year-over-year growth rate over the duration of the assessment period. It is derived as follows: CAGR = (Year 10 TID / Year 1 TID)^(1 / 9) – 1

[44] 10 Year Growth Rate starting in 2011; only 9 years were used prior to 2011

Most assessment areas continue to experience a flattening growth rate in both their ten-year peak demand and energy forecasts. This is largely due to widespread implementation of energy efficiency and conservation programs, DSM, and increasing installations of distributed energy resources (DERs) that are nonobservable by utilities and treated as passive load modifiers. **Figure 4.3** shows the compounded annual demand growth rate by assessment area.

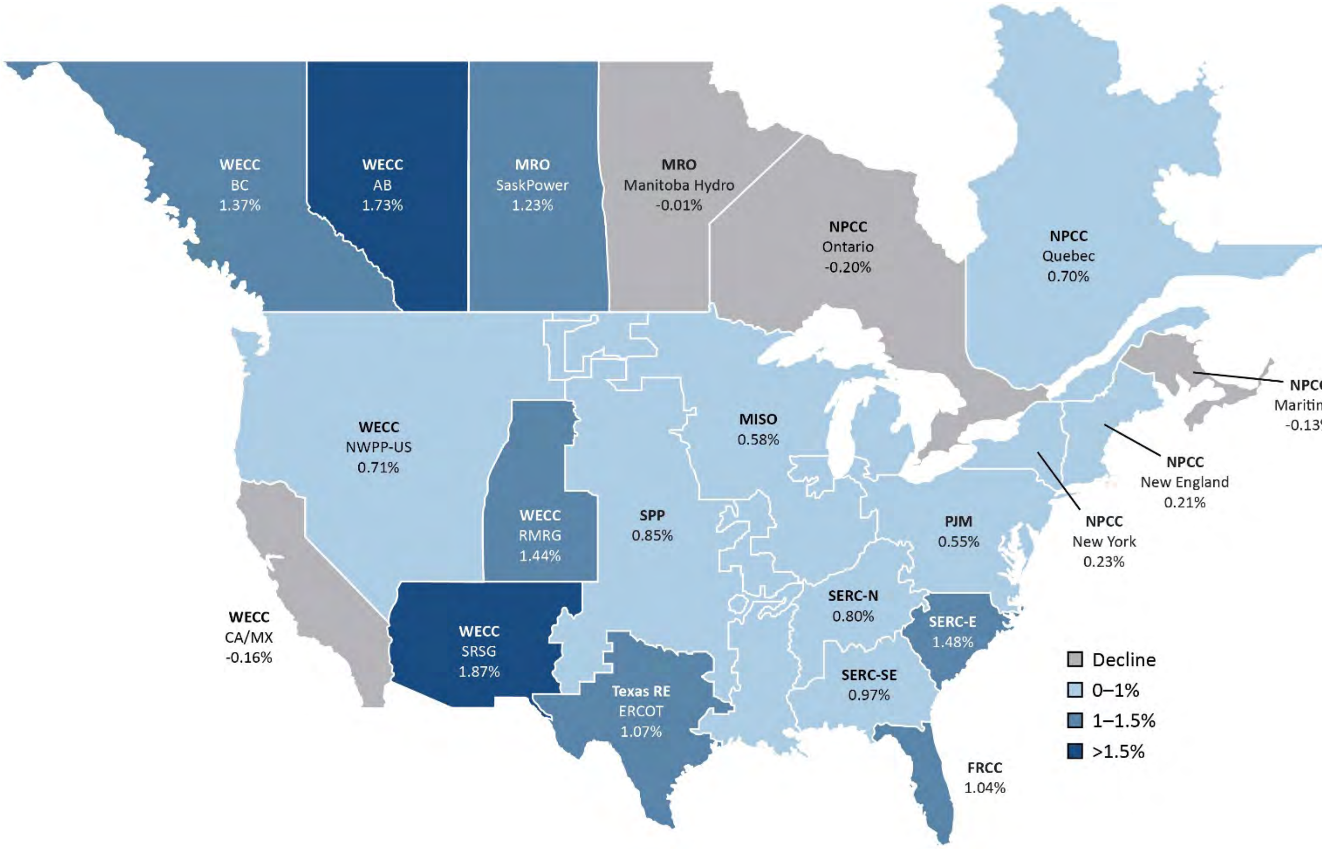


Figure 4.3: GR-Map: Compound Annual Growth Rate by Assessment Area–Demand

Historically, while utilities have worked to implement a variety of programs to reduce their peak load obligation; these reductions in energy forecasts also point to a growing change to the system as the currently metered energy needed in future years is decreasing. This is verified by examining the energy reported in past years. **Figure 4.4** shows the actual energy served from 2010 to 2015. The calculated trend line shows a decrease from the 4,555 TWhs used in 2010 to 4,526 TWhs in 2015; this is a reduction of 29 TWhs or 0.64 percent.

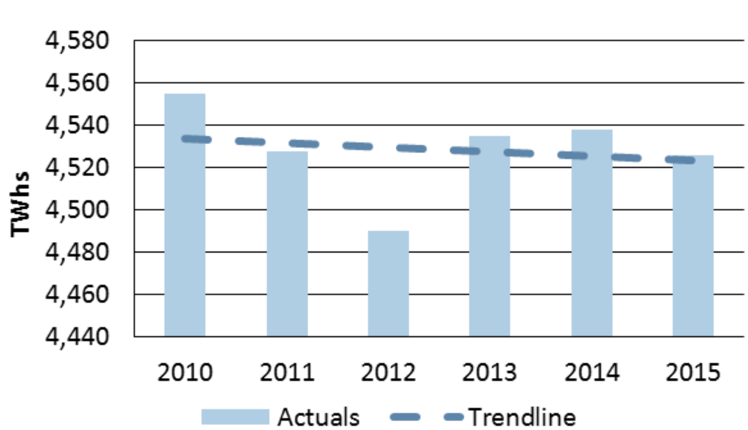


Figure 4.4: 2010–2015 Actual Energy Used to Serve Load

As a majority of renewable energy is not generated across the peak. The increasing amounts of behind-the-meter and renewable generation will continue to decrease net energy used to serve load while not similarly decreasing peak load obligations. This trend should continue unless the energy generated by behind-the-meter generation is both observable and contributing to energy profiles instead of being treated as a passive load modifier. Economic conditions also have an important impact on annual energy usage.

New energy efficiency programs are still a key component for assessment areas to use to manage both peak demand and energy throughout the year. **Figure 4.5** below shows the *2016 LTRA* reference case projections of new programs expected to decrease overall system peak load demand by 26.3 GW through the end of the assessment period, or approximately 2.8 percent of the overall 945.7 GW of expected peak load.

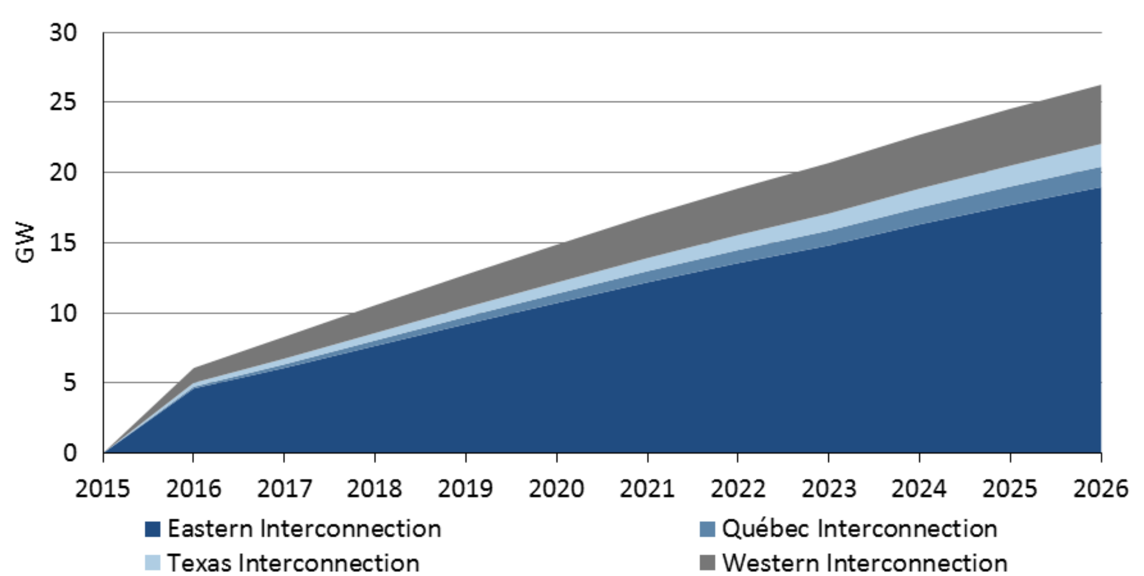


Figure 4.5: Energy Efficiency Projections by Interconnection through 2026

Demand-Side Management

There are a variety of demand response (DR) programs that contribute to an assessment area's ability to manage load; these may consist of behind-the-meter supply resources and/or load-reducing programs that are available at specific times of the year. For the purposes of this assessment, only the expected amount that are likely to respond when called to reduce peak load are collected. Each assessment area may have different mechanisms in place for accounting for this available DR and forecasting these program's availability ten years out. Any significant changes to these forecasting methods are presented and reviewed annually by the Reliability Assessment Subcommittee.

Figure 4.6 below shows the total system DR considered available for the first year's summer and winter peak from each of the last six LTRAs. A decade ago, when there was a strong focus on the development of DR programs, growth projections were high for the new programs. Comparing the total, system-wide DR for year one of the *2011 LTRA* and the *2016 LTRA* yields a drop in the summer from 44.0 GW to 31.9 GW (27.5 percent) and in the winter from 42.7 GW to 21.6 GW (49.4 percent). Contributing factors to this decline include increased energy efficiency and solar installations. These have reduced the amount of discretionary load that is available to be reduced on demand, maturation of DR programs and their participants' understanding of them, and regulatory and market rule changes that apply to DR.

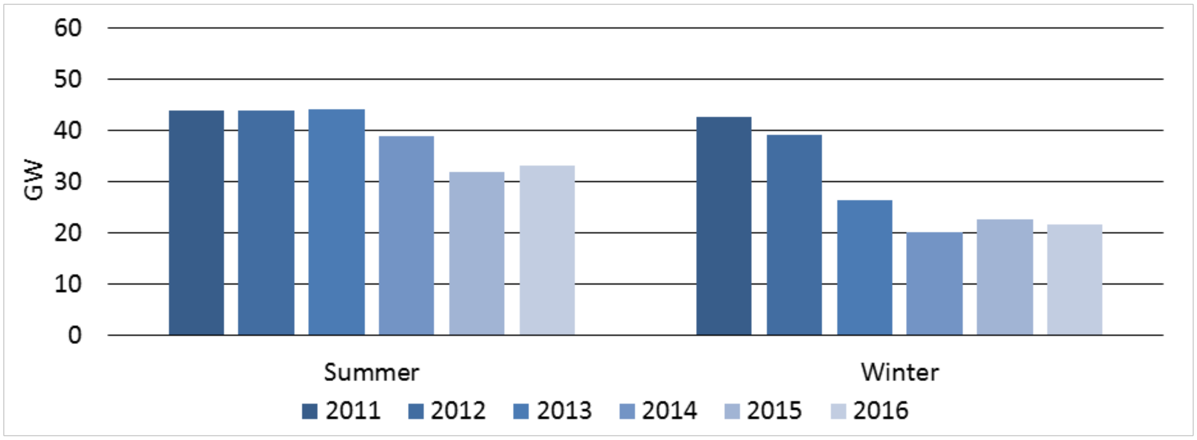


Figure 4.6: Demand Response Available in Year One of 2011LTRA–2016 LTRA

In October of 2008, FERC issued Order No. 719,[45] which required wholesale markets to accept most DR bids in all markets. In March 2011, FERC issued Order No. 745,[46] which required that wholesale energy markets provide equal compensation to DR providers for conserving energy at the same market rate as generators are paid for producing it. Order No. 745 was brought to the Court of Appeals for the District of Columbia Circuit and challenged as beyond the authority of FERC. Although the decision of the Court of Appeals and subsequent appeal to the Supreme Court created some uncertainty for the future of market-based DR programs, available DR does not appear to have been significantly affected. In January of 2016, the Supreme Court ruled that the Federal Power Act does authorize FERC to regulate "the sale of electric energy at wholesale in interstate commerce" and "to ensure that rules or practices affecting wholesale rates are just and reasonable."[47]

The moderate changes shown in the annual forecasts of enrollments of DR in the past three years may reflect changes to market rules or market structures, improvements in technologies to facilitate participation, and local utility commission drivers to increase load management capabilities through DR.

Generation Fuel Mix

Examining the existing and projected generation mix is crucial to assessing potential risks to reliability. Specifically, whether or not the projected capacity additions will provide adequate levels of essential reliability services (ERS) components to support the overall state of the system. A total of 1,280 GW of nameplate capacity are expected to be available to serve load by the end of 2016. **Figure 4.7** shows this system-wide, 1,280 GW of anticipated nameplate capacity by generation type. Many additional generating units are planned for the next ten years to meet a combination

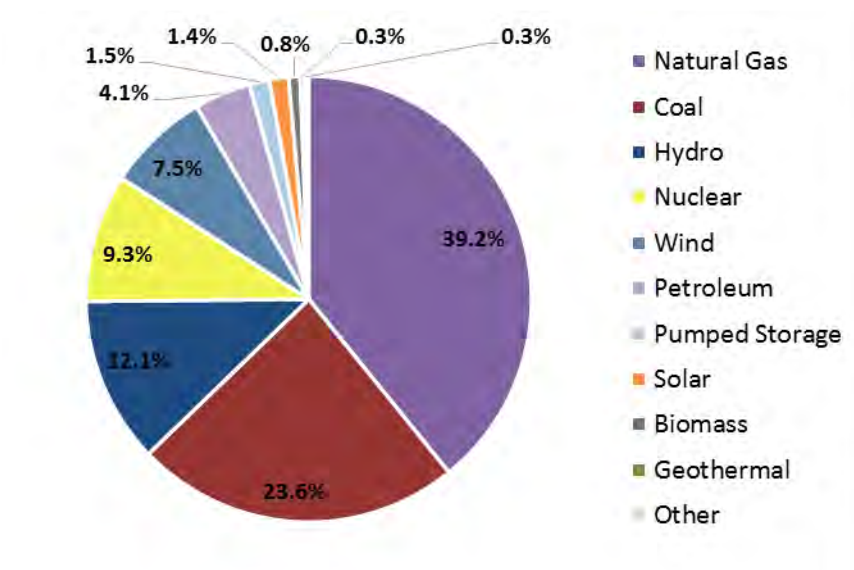


Figure 4.7: 2016 Existing & Tier 1 Nameplate Capacity by Fuel Type

[45] FERC Order No. 719: Wholesale Competition in Regions with Organized Electric Markets
[46] FERC Order No. 745: Demand Response Compensation in Organized Wholesale Energy Markets
[47] Supreme Court Decision: January 25, 2016

of demand growth and the need for replacement generation as other units retire. **Figure 4.8** shows the system's aggregated planned additions separated by generation type and planned tier designator. The three tiers, shown in **Figure 4.8**, indicate some degree of certainty for each unit. Generation in Tier 1 is considered to be very certain and can be expected to be available for the assessment while Tier 2 is less certain and Tier 3 is not included in a reserve margin analysis. While there are many resource types in the queue for resource planning expectations, a significant majority of all planned generation will rely on natural gas.

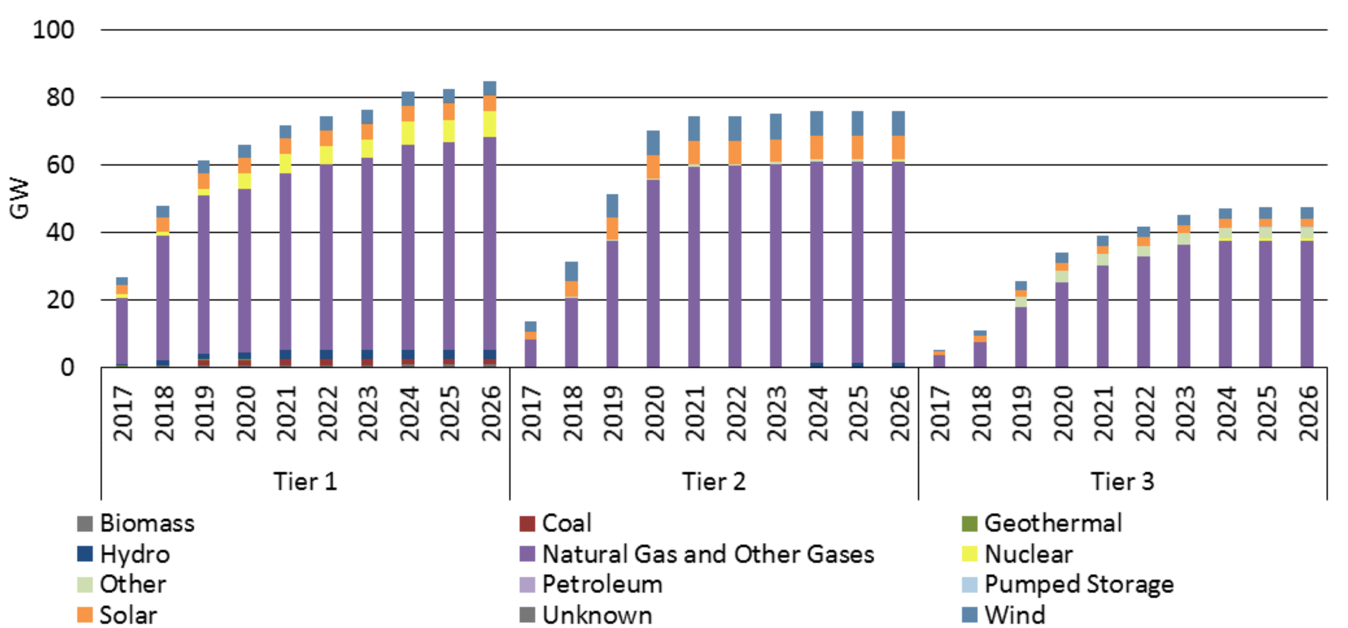


Figure 4.8: Planned Nameplate Capacity Additions by Generation Type and Tier

Table 4.4, **Table 4.5**, **Table 4.6**, and **Table 4.7** show the total nameplate capacity for each fuel type by Interconnection. These include actual values reported for 2015 and all planned additions and confirmed retirements projected through 2026.

Table 4.4: Eastern Interconnection Total Anticipated Nameplate Capacity by Fuel Type

	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	6,379	6,812	433	6.8%
Coal	242,371	233,825	(8,546)	-3.5%
Geothermal	-	20	20	-
Hydro	43,736	44,845	1,109	2.5%
Natural Gas	332,998	386,298	53,300	16.0%
Nuclear	104,702	106,238	1,535	1.5%
Other	889	889	-	0.0%
Petroleum	50,950	48,814	(2,136)	-4.2%
Pumped Storage	16,165	16,165	-	0.0%
Solar	1,634	6,233	4,599	281.5%
Wind	46,324	57,424	11,100	24.0%
Total	846,148	907,563	61,415	7.3%

Table 4.5: Texas Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	210	210	-	0.0%
Coal	20,796	20,796	-	0.0%
Hydro	544	544	-	0.0%
Natural Gas	50,114	58,110	7,996	16.0%
Nuclear	5,268	5,268	-	0.0%
Solar	288	2,053	1,765	613.5%
Wind	15,909	26,934	11,025	69.3%
Total	93,129	113,915	20,786	22.3%

Table 4.6: Québec Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	327	447	119	36.5%
Hydro	40,943	41,673	729	1.8%
Natural Gas	570	570	-	0.0%
Petroleum	436	436	-	0.0%
Wind	3,260	3,923	663	20.3%
Total	45,536	47,048	1,512	3.3%

Table 4.7: Western Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	3,616	3,764	148	4.1%
Coal	38,379	36,245	(2,134)	-5.6%
Geothermal	3,862	4,171	309	8.0%
Hydro	68,736	69,622	886	1.3%
Natural Gas	101,972	105,872	3,900	3.8%
Nuclear	7,679	7,679	-	0.0%
Other	2,962	2,974	12	0.4%
Petroleum	1,143	1,133	(10)	-0.9%
Pumped Storage	2,450	3,020	570	23.3%
Solar	9,476	16,907	7,431	78.4%
Wind	21,118	22,715	1,597	7.6%
Total	261,392	274,101	12,709	4.9%

Transmission Adequacy

Maintaining sufficient transmission capacity is a key component of understanding and analyzing an assessment area's transmission adequacy. Load and resources are subject to a variety of factors that could lead to rapid changes to electric transmission infrastructure. This is generally restricted by slow planning, siting, and construction. While many generating units do require years to plan and build, unexpected retirements and the addition of generation with much shorter build times can stress the current transmission system. Through modeling and power flow studies, system planners provide the foundation for these essential transmission projects to be developed.

A FERC technical conference was held in August of 2016 that discussed competitive transmission development processes wherein Panel Four of this discussion involved Interregional Transmission Coordination Issues.[48] Amidst the discussion was an overview of several reports from The Brattle Group that highlighted studied transmission planning needs, trends, and recommendations.[49] As unprecedented shifts in the makeup of available generating resources and load occur, policy makers and regulators should advocate for developed processes that allow for transmission solutions that meet both reliability requirements and anticipated changes to due to environmental regulations. Tabulated below are the summarized major transmission project expansions provided in this report.

FRCC

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects, shown in **Table 4.8**, are primarily related to expansion in order to serve forecasted growing demand, and they are related to maintaining the reliability of the BES in the longer-term planning horizon or for resource integration.

Table 4.8: FRCC Planned Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Levee–Midway	Florida Power & Light Company	Reliability	150	500kV (ac)	2023

MISO

MISO's Transmission Expansion Plan[50] (MTEP15) includes proposals for over $2.75 billion[51] in transmission infrastructure investment through 2024, and these fall into the following categories:

- **90 Baseline Reliability Projects (BRP) totaling $1.2 billion:** BRPs are required to meet NERC reliability standards.
- **12 Generator Interconnection Projects (GIP) totaling $73.6 million:** GIPs are required to reliably connect new generation to the transmission grid.
- **1 Market Efficiency Project (MEP) totaling $67.4 million:** MEPs meet Attachment FF requirements for reduction in market congestion.
- **242 Other Projects totaling $1.38 billion:** Other projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit but do not meet the threshold to qualify as Market Efficiency Projects.

[48] FERC Docket No. AD16-18-000; Notice Inviting Post-Technical Conference Comments; August 3, 2016
[49] The Brattle Group: Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future; June 6, 2016
[50] MISO's Transmission Expansion Plan
[51] The MTEP15 report and project totals reflect all project approvals during the MTEP15 cycle, including those approved on an out-of-cycle basis prior to December 2015.

Several of MISO's major transmission projects are shown in Table 4.9.

Table 4.9: MISO Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Great Northern Transmission Line–partial segment	Minnesota Power (Allete, Inc.)	Hydro Integration	220	500kV (ac)	2020
MVP Portfolio 1–Ellendale to Big Stone South	Otter Tail Power Company	Reliability	165	345kV (ac)	2019
MVP Portfolio 1: N LaCrosse–N Madison-Cardinal-Eden-Hickory Creek	American Transmission Co. LLC	Reliability	161.8	345kV (ac)	2024
Great Northern Transmission Line–partial segment-	Minnesota Power (Allete, Inc.)	Hydro Integration	160	500kV (ac)	2020
MVP Portfolio 1: Lakefield Jct.–Winnebago–Winco –Kossuth County & Obrien County–Kossuth County–Webster	Ameren Services Company	Reliability	122	345kV (ac)	2018

Manitoba Hydro

Manitoba Hydro has plans for a significant number of system enhancement projects, including those listed in Table 4.10. Manitoba Hydro is planning for an addition of the third 2,000 MW Bipolar HVdc transmission system in 2018. Bipole III provides an alternative path to serve Manitoba load in the event of a major station loss or corridor loss associated with Bipole I and II. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020, as a result of an 883 MW transmission service request. Manitoba Hydro is also expecting a new 230 kV interconnection from Birtle South (Manitoba) to Tantallon (Saskatchewan) station with an in-service-date of 2020, as a result of a 140 MW transmission service request. The reliability impact of the 230 kV line is not evaluated in this assessment because a construction agreement has not been finalized with the customer yet.

Table 4.10: Manitoba Hydro Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Bipole 3–Riel	Manitoba Hydro	Reliability	1800	500kV (dc)	2018
Great Northern Transmission Line (Canadian Portion)	Manitoba Hydro	Reliability	146	500kV (ac)	2020

SaskPower

Saskatchewan has several major transmission projects for reliability during near-term of the assessment period. These projects, identified in Table 4.11, are heavily dependent on load growth, and involve the construction of approximately 570 miles (918 km) of transmission lines.

Table 4.11: SaskPower Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Pasqua–Swift Current Area Reinforcement	SaskPower	Reliability	125	138kV (ac)	2019
Pasqua–Swift Current Area Reinforcement	SaskPower	Reliability	125	230kV (ac)	2019
Aberdeen–Wolverine Area Reinforcement	SaskPower	Reliability	68	230kV (ac)	2017
Tantallon Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2017
Regina–Moose Jaw Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2020
Regina–Moose Jaw Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2019
Aberdeen–Wolverine Area Reinforcement	SaskPower	Reliability	35	138kV (ac)	2017
Tantallon–AMBirtle line	SaskPower	Reliability	31	230kV (ac)	2020

Maritimes

Transmission development in the Maritimes area during the assessment period includes projects shown in Table 4.12. Additional projects include the installation of a 345 kV breaker in series with an existing breaker at NB's Point Lepreau terminal in Spring 2016. This was done to mitigate contingencies and reduce import restrictions from New England. During the winter of 2016/17, the installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of nine miles, will be completed and will increase capacity. This was done to improve the ability to withstand transmission contingencies in the area between NB and PEI. A 475 MW High Voltage Direct Current (HVdc) undersea cable link (Maritime Link) between Newfoundland, Labrador, and NS will be installed by early 2018. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 153 MW coal-fired unit in NS by mid-2020. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing transformer at the Keswick terminal in NB. This is to mitigate the effects of transformer contingencies at the terminal.

Table 4.12: Maritimes Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
NS-NL Tie (Newfoundla—Nova Scotia)	Nova Scotia Power	Variable/ Renewable Integration	100	200kV (dc)	2017
Y-104 (West Royalty—Church Road)	Maritimes Electric	Variable/ Renewable Integration	50	138kV (ac)	2017
Harbour East (Dartmouth East—Eastern Passage)	Nova Scotia Power	Reliability	10	138kV (ac)	2018

New England

Several major transmission projects for New England are identified in **Table 4.13**. One significant 345 kV project that is important to the continuation or enhancement of system or subarea reliability is projected to come on-line during the assessment period. This project is the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England, and then developing and implementing solutions to address existing and projected transmission system needs. The major project under development in New England is the Greater Boston project. The Greater Boston upgrades, which are certified to be in service by 2019, are critical to improving the ability to move power into the Greater Boston area, and also to move power from northern New England to southern New England. This set of upgrades includes a +/- 200 MVAR 345 kV interconnected static synchronous compensators (STATCOMs) in Maine that will also help to address concerns with the potential for system separation due to significant contingencies in southern New England.

Table 4.13: New England Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	98	320kV (dc)	2019
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	60 (Under Ground)	320kV (dc)	2019
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	34	345kV (ac)	2019

New York

The Transmission Owner Transmission Solutions (TOTS) consists of three transmission projects in central New York, downstate New York, and New York City. The TOTS are part of the Con Edison and the New York Power Authority (NYPA) filing in response to a November 2012 Order from the NYSPSC that recognized significant reliability needs would occur if the Indian Point Energy Center (IPEC) were to become unavailable.[52] The TOTS transmission projects are described in the following three projects:

Project One: The Ramapo-Rock Tavern project will establish a second 345 kV line from Con Edison's Ramapo 345 kV substation to Central Hudson Gas and Electric Corporation's (CHGE) Rock Tavern 345 kV substation. The project will increase the import capability into Southeastern New York (SENY); this includes New York City, during normal and emergency conditions and will provide a partial solution for system reliability should the IPEC retire. The

[52] New York Public Utilities Commission; Order Instituting Proceeding and Soliciting Indian Point Contingency Plan; November 2012

project will be located in Orange and Rockland Counties in New York along the right-of-way for the existing Con Edison 345 kV Feeder 77 (Ramapo to Rock Tavern) and use existing transmission towers. The transmission line terminals are located in NYBA's Zone G. This project involves work that will be performed by Orange & Rockland Utilities (O&R) and CHGE, as such, Con Edison has and will continue to coordinate this effort with both O&R and CHGE.

Project Two: The Marcy South Series Compensation project is a transmission improvement project that adds switchable series compensation to increase power transfer. This is done by reducing series impedance over the existing 345 kV Marcy South lines. Specifically, the project adds 40 percent compensation to the Marcy-Coopers Corners 345 kV line, 25 percent compensation to the Edic-Fraser 345 kV line, and 25 percent compensation to the Fraser-Coopers Corners 345 kV line through installation of series capacitors. The project also involves upgrades at Marcy and Fraser 345 kV substations. These upgrades involve reconductoring approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345 kV line (FCC-33) with a higher thermal-rated conductor. The project increases thermal transfer limits across the Total East Interface and the UPNY/SENY Interface.

Project Three: The third project splits an existing feeder between Goethals and Linden Cogen substations, and it will provide a similar solution at a lower cost and with lower environmental impacts. This project is located in Staten Island and Brooklyn, New York; and Union County (Linden), New Jersey.

Ontario

Several major transmission projects for Ontario are identified in **Table 4.14**. Northwestern Ontario is connected to the rest of the province by the 230 kV double-circuit East–West Tie. Local load growth is forecasted as a result of an active mining sector in the region. To address load growth, additional capacity is required to maintain reliable supply to this area under the wide range of possible system conditions. Anticipated to be in service in 2020, the expansion of the East–West Tie with the addition of a 230 kV new double-circuit transmission line will provide reliable and cost-effective long-term supply to the Northwest.

Table 4.14: Ontario Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
QFW	Hydro One	Economics/ Congestion	93	320kV (dc)	Delayed/ Unknown
East-West Tie	Hydro One	Reliability	240	320kV (dc)	2020
West of Thunder Bay Lines	Hydro One	Reliability	250	345kV (ac)	2022

Forecasted demand growth in the areas west of Thunder Bay and north of Dryden will require increased transfer limits west of Mackenzie Transformer Station (TS). Development work is proceeding for a new 230 kV double-circuit line between Lakehead TS and Mackenzie TS, and a new single-circuit line between Mackenzie TS and Dryden TS.

Forecasted demand growth in the Ottawa area will require reinforcements to the transmission system to relieve future thermal constraints. Plans including line reconductoring are already underway to address the thermal constraints.

Ontario is monitoring the progress of the continued operation of nuclear units at Pickering Nuclear Generating Station. Pickering Nuclear Generating Station units connect directly to the 230 kV system at Cherrywood Transformer Station, which is located in the east side of the greater Toronto area. The retirement of Pickering Nuclear Generating Station requires an additional 230 kV supply source for the area. This will be provided by the new Clarington 500/230 kV transformer station with a planned 2018 in-service date. Clarington Transformer Station will also improve load restoration capabilities east of Cherrywood following certain contingencies.

Bulk power transfers into the GTA from the west are expected to increase as a result of the planned shutdown of Pickering Generating Station, major refurbishment of other nuclear generating units, and the incorporation of significant amounts of renewable generation in Ontario. Because of the increased bulk power transfers and increasing local demand, the capacity of the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS are forecasted to be exceeded by 2022. Planning studies are being finalized. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station, with eight 230 kV circuit terminations, and 12 km of new double-circuit line sections connecting the new Milton TS to Hurontario Switching Station.

Hydro Québec

The major transmission projects in the Hydro Québec footprint are: the Romaine River Hydro Complex Integration, the Chamouchouane–Montréal 735-kV Line, the Northern Pass Transmission Project, and the Champlain-Hudson Power Express Project.

The Romaine River Hydro Complex Integration

Construction the Romaine River Hydro Complex project is presently underway. Its total capacity will be 1,550 MW. Romaine-2 (640 MW) was commissioned in December 2014, and Romaine-1 (270 MW) in December 2015. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017–2020 at Montagnais 735/315-kV substation. The Québec area is reiterating its commitment to sustainable development by focusing on renewable energy at the Romaine complex, which will help meet current needs without jeopardizing the energy supply of future generations.

Main system upgrades for this project has required construction of a new 735-kV switching station Aux Outardes, which is located between existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station, and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua substations. This upgrade was commissioned in Summer 2015.

The Chamouchouane–Montréal 735-kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735-kV line in the near future in order to meet the reliability standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km or 250 miles). The new 735kV substation is required to fulfill two objectives: providing a new source of electricity supply on the north shore of Montreal and connecting the new 735kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line is scheduled for the 2018–2019 winter peak period. Public information meetings have been held and the construction phase has begun.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England by 1,090 MW is currently under study. It involves the construction of a ±320-kV dc transmission line about 49 miles (79 km) long from Des Cantons 735/230-kV substation to the Canada–United States border. This line will be extended into the United States to a new substation built in Franklin, New Hampshire. The project in Québec also includes the construction of an HVdc converter at Des Cantons and a 320-kV dc switchyard. The planned in-service date is 2019.

The Champlain-Hudson Power Express Project

This project to increase transfer capability between Québec and New York by 1,000 MW is currently under study. It involves the construction of a ±320-kV dc underground transmission line about 50 km (31 miles) long from Hertel

735/315-kV substation just south of Montréal to the Canada–United States border. This line will be extended underground and underwater (Lake Champlain and the Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of an HVdc converter at Hertel. The planned in-service date is currently under review.

Upcoming Regional Projects

Other regional substation and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas. There are another dozen in other areas with in service dates from 2016 to 2020, consisting mostly of 315/25-kV and 230/25-kV distribution substations to replace 120-kV and 69-kV infrastructures. Two of these more notable regional transmission projects are shown in **Table 4.15**.

Table 4.15: Québec Regional Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
La Romaine 3-4	Hydro-Québec	Hydro Integration	129	315kV (ac)	2017
Line CHM-MTL	Hydro-Québec	Reliability	250	735kV (ac)	2018

SERC

The major transmission projects in the SERC footprint are as follows:

- Construction of the Union-Tupelo and Selmer-West Adamsville 161 kV lines support voltage and the changing flows in the area.
- Pin Hook needs an additional 500/161 kV transformer to alleviate overloads in the SERC-N area.
- Construction of the Plateau 500 kV Substation will alleviate decreasing voltages and higher flows on lines caused by increased loads in the area.
- A new static VAR compensator (SVC) installation at the Davidson 500 kV substation will increase dynamic reactive reserves for support.
- Construction of the 55 mile Vogtle to Thompson 500 kV line will support the addition of future generation.
- New 230 kV transmission projects are under construction in conjunction with VC Summer Nuclear Units 2 and 3.

SPP

The SPP assessment area's 2016 Board-of-Directors-approved SPP Transmission Expansion Plan Report (STEP) provides details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. The 2016 SPP Transmission Expansion Plan (STEP) contains a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. These projects consist of $6.1 billion in new transmission and upgrades. Several of these major transmission projects are shown in **Table 4.16**.

Table 4.16: SPP Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Sibley—Mullin Creek	TSMO	Economics/ Congestion	105	345kV (ac)	2016
Cherry Co.—Gentleman	NPPD	Reliability	110	345kV (ac)	2018
Cherry Co.—Holt Co.	NPPD	Reliability	117	345kV (ac)	2018
Tuco—Yoakum	SPS	Reliability	107	345kV (ac)	2020

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative three-year study process that includes 20-Year, 10-Year, and Near Term Assessments.

- The 20-Year Assessment (ITP20), performed once every three (3) years, identifies transmission projects, generally above 300 kV, needed to develop a grid flexible enough to provide benefits to the region across multiple scenarios.
- The 10-Year Assessment (ITP10), performed once every three (3) years, focuses on facilities 100 kV and above to meet system needs over a 10-year horizon.
- The Near-Term Assessment (ITPNT), performed annually, assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs.

The goal of transmission integration studies[53] to evaluate the adequacy of each Integrating Entity's transmission facilities at the time of their integration date and whether they are in compliance with NERC Reliability Standards, SPP Criteria, and Transmission Owner-specific planning criteria (if a waiver allows for the SPP or NERC Criteria to be superseded).

An initial integration study was conducted in 2013 for the Integrating Entities that identified projects needed before and after the October 2015 integration date. This latest study was a refresh of the initial study to determine if any supplemental issues emerged when considering more current information.

SPP leveraged the 2016 ITP Near-Term model set as the starting point for the analysis. The Integrating Entities provided updates to topology, generation dispatch, and load information.

Texas RE-ERCOT

Several of Texas RE-ERCOT's major transmission projects are shown in **Table 4.17**. The recently updated ERCOT future transmission projects list includes the additions or upgrades of 3,954 miles of 138-kV and 345-kV transmission circuits, 24,159 MVA of 345/138-kV autotransformer capacity, and 3,005 MVar of reactive capability projects. These are planned in the TRE-ERCOT Region between 2016 and 2024.

Table 4.17: TRE-ERCOT Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Lobo to North Edinburg: Construct 345 kV Line	ETT	Reliability		345kV (ac)	2016
Add second circuit to SLU panhandle loop	SHRY	Economics/ Congestion		345kV (ac)	2018
New 345kV line from Loma Alta to N Edinburgh	SLU	Reliability		345kV (ac)	2016

A new Houston Import Project, 130-mile 345 kV double circuit line (each circuit rated at 5000 Amps) from Limestone to Gibbons Creek to Zenith, is planned to be in service before the summer peak of 2018.[54] The Houston area is one of the two largest demand centers in the ERCOT system and the fourth largest city in the United States. The Houston area demand is met by generation located within the area and by importing power via high-voltage lines into the area from the rest of the ERCOT System. This new line will support anticipated long-term load growth

[53] SPP Integrated Transmission Planning
[54] ERCOT: Houston Import RPG Project; April 8, 2014

in the Houston region. Power imports into the Houston area are expected to be constrained until the new import line is constructed.

In July 2014, the owners of the Frontera generation plant, a 524 MW natural gas facility located on the west side of the Lower Rio Grande Valley (LRGV), announced that they were planning to switch part of the facility (170 MW) out of the ERCOT market in 2015. This entire facility would no longer be available to ERCOT in 2016. In June, 2016, the ERCOT Board of Directors endorsed the reliability need for the two 300 MVAr SVCs located inside the LRGV to be in service prior to summer of 2021 to meet ERCOT and NERC reliability criteria for the LRGV.

Chapter 5: Additional Reliability Issues

NERC continues to monitor and report on a variety of other issues that are generally categorized as lower risk. While these may not require immediate attention or action, there is a consistent need to assess all system changes or impacts to be aware of any risks before they develop. The *2016 LTRA* identifies the following items as issues, trends, and events that warrant further attention and study:

- EPA Clean Power Plan (CPP)
- Grid energy storage
- System short circuit strength
- Modeling
- Reactive power requirements for nonsynchronous generation
- System restoration
- Reactive power supporting devices
- 2017 solar eclipse

Clean Power Plan

On August 3, 2015, the EPA issued its final rule, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*.[55] Initial compliance of the final rule was set to begin in 2022 with final compliance in 2030. The final rule aims to cut CO_2 emissions from existing power plants to 32 percent below 2005 levels by 2030. NERC conducted an analysis of the final rule in order to assess potential reliability risks to the BPS as a result of the rule.[56]

As a result of the analysis, NERC determined that already occurring changes to the resource mix would accelerate if the final rule were to be implemented. Among NERC's key findings of its analysis are the following:

- The CPP is expected to accelerate a fundamental change in the electricity generation mix in the United States and transform grid-level reliability services, diversity, and flexibility.
- Integration of large amounts of renewables are expected to occur on the BPS regardless of the CPP.
- The CPP is expected to further flatten annual energy demand growth.
- Resource mix changes have regional significance, spurring the need for additional transmission and pipeline infrastructure.

NERC recommended that, due to the wide ranging effects of the CPP, planning processes should already be underway to ensure that requisite transmission and pipeline infrastructure be built in a timely manner. NERC further recommended that planning coordinators and transmission planners should conduct system reliability evaluations to identify areas of concern. NERC continues to hold itself out as a resource for states and planners as state submittals are being formulated. Finally, NERC also recommended that work should be continued around sufficiency guidelines for essential reliability services (ERSs) and evaluation of the effects that distributed energy has on the BPS.

On February 9, 2016, the Supreme Court stayed implementation of the CPP pending judicial review. The stay will remain in effect through the review of the CPP by the Court of Appeals for the District of Columbia Circuit (D.C.

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[55] EPA: Clean Power Plan for Existing Units
[56] NERC Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Circuit) *and* until the Supreme Court decides the matter in the event that it is ultimately appealed to the Supreme Court. This legal process could continue into the middle of 2018. The stay of the final rule has an impact on the ultimate validity of the final rule as well as the timing of it should it ultimately be upheld by the courts. It is also important to note that NERC determined that many of the changes occurring on the BPS are occurring regardless of the CPP and should therefore be incorporated into system and operational planning.

System Short-Circuit Strength

The safe, reliable operation of electrical power systems requires the ability to predict and model the sources of fault current in order to select equipment properly rated for the required duty and to properly set protective relays for selective operation. Nonsynchronous powered generating plants are also sources of fault current and are considered in addition to typical synchronous generating sources.

Synchronous machines in the electric power grid, their operation, and respective short-circuit behavior have been established and are well understood in comparison to some types of nonsynchronous power plant fault current and performance. A nonsynchronous power plant is separated from conventional generation by its unique short-circuit behavior. The unique short-circuit characteristic for nonsynchronous machines emanates from either when an induction generator is directly connected to the grid or when the nonsynchronous machine is decoupled from the grid through power electronic devices (e.g., inverters). Therefore, accurate short-circuit studies are needed to determine that the maximum short-circuit contribution from a given machine is within the limits of the circuit breakers and that protective devices are coordinated to function properly over a specific range of potential conditions.

Short-Circuit Fault Contribution of Nonsynchronous Resources

The short-circuit fault contribution from large nonsynchronous plants that are connected to the transmission voltages are a primary concern to safe and reliable operations of the bulk electric power system. Nonsynchronous plants of interest typically consist of multiple wind turbines/photovoltaic (PV) systems connected to transmission facilities (greater than 100kV). Here, the importance of both balanced and unbalanced short-circuit fault analysis to determine the worst case fault given select components of a nonsynchronous plant is discussed. This section does not focus on nonsynchronous collector systems nor internal plant protective relaying problems.

Nonsynchronous Plant Types

A significant difference between a nonsynchronous plant and a typical power plant is the total number of machines/units employed at a transmission bus. A typical conventional power plant (i.e., combustion, hydro, or steam) might consist of a single unit or a few large units. Therefore, the components for short-circuit modeling of a conventional power plant includes each generator and its respectively sized step-up transformer. In contrast, a nonsynchronous power plant of similar MW size to the conventional generator will consist of many machines/units, their individual step-up transformers, a medium voltage collector system (i.e., cabling), and a substation transformer in order to be modeled correctly for short circuit studies.

Industry has divided large megawatt rated wind turbines into five different groups based on their machine type, speed control capabilities, and operational characteristics. The following list provides the wind turbine groups by their type and associated machine:

- Type I, squirrel cage induction generator
- Type II, squirrel cage wound rotor induction generator with external rotor resistance
- Type III, double fed asynchronous generator
- Type IV, full power converter generator (PV/wind)
- Type V, synchronous generator mechanically connected through a torque converter

For short-circuit fault current, Types I through IV are of greater concern than Type V wind turbines. The detailed behavior and characteristics of fault contributions of nonsynchronous plants can be very specific to a particular turbine design. Turbine manufacturers must provide accurate information on balanced and unbalanced fault performance for the particular turbines in a specific plant. Photovoltaic (PV) systems generally use a full power dc-ac converter and typically produce similar fault characteristics to the Type IV wind turbine.

System Strength

As the number of inverter-based resources increases, and as the number of dispatched synchronous sources decreases, there will be an operating point when the grid is no longer strong enough to support stable operation of the power electronic converters connected within the wind and PV plants. Very few systems have faced this issue in actual operation (e.g., South Texas Sub-Synchronous Resonance Event of 2009). Knowledge of this issue is built upon converter performance tests and detailed analysis using transient simulation tools, such as Power Systems Computer Aided Design (PSCAD) and Electromagnetic Transients Program (EMTP). Since such tools and analytical methods are not well suited to studying large-scale risks for many plants over wide geographic areas, the challenge is to take what is learned from detailed analysis of a few plants and extend that learning across larger regions using more practical methods.

Short circuit ratio (SCR) is a calculation used to screen for weak grid conditions near power electronic converters. This method has been borrowed from screening for weak grid conditions near HVdc converters and is currently being applied to nonsynchronous plants.[57]

An adequate SCR for today's nonsynchronous inverter designs is defined at the point of interconnection and typically has a calculated ratio in the range of 3-5, where 3 is the minimum ratio to be considered sufficiently robust and 5 is considered vigorous. When the calculated SCR at a plant interconnection point is lower than 3, there is significant concern that the internal plant controls will not function in a stable manner (i.e., the positive sequence stability representation of the plant may not represent the true behavior of the plant or be mathematically stable). Low SCRs increases the chance of subsynchronous behavior and control interactions among neighboring devices employing power electronics.[58]

The low SCR problem is typically identified and addressed during interconnection study stages of a nonsynchronous plant. This issue is fundamentally a local problem and can be remedied with upgrades, such as synchronous condensers. However, it is an ongoing issue because as synchronous generators retire or network topology changes take place, it is possible that an area in which nonsynchronous generators have been interconnected can evolve into a weaker system. As a result, the SCR should be used to re-evaluate the strength of the interconnection points due to temporal network modifications.

The SCR ratio is not included in daily system operations as it is not achievable to determine critically diminished points in the system and then be able to implement immediate corrective actions (i.e., install equipment). This is to ensure a sufficiently robust solution over a reasonable range of typical operating conditions.

Modeling

NERC is committed to assessing the quality of the power system models used to plan the BPS. NERC is also committed to support the development and advancement of models and modeling practices to ensure that long-term and short-term planning engineers have the tools and capabilities to plan and operate the BPS. Currently under evaluation or a development plan are case quality metrics, dynamic load modeling, and adequate modeling of DERs.

[57] SCR is the ratio of the available system strength (measured in short circuit MVA) to the MW rating of the wind or PV plant.
[58] ERCOT: System Strength Assessment of the Panhandle System 2016

Case Quality Metrics

NERC performed its *Phase 2 Assessment of Case Quality Metrics*[59] future-year planning cases for the Eastern, Western, and Texas Interconnections. This included reassessment of the Phase 1 metrics[60] as well as development of new metrics for Phase 2, particularly with respect to dynamic models. NERC is working with the case creation entities designated, pursuant to MOD-032, to incorporate the metrics (as appropriate) for their interconnections to improve the performance scores for their models moving forward. A number of dynamics case modeling issues were identified in the Phase 2 assessment, such as power development fractions for turbine-governor models, generator time constants and inertia constants, and generator saturation factors. Reassessment of the Phase 1 metrics showed no adverse trends between the two case years, and NERC will continue analyzing case quality to build these trends over the longer-term.

Dynamic Load Modeling

Dynamic load models, such as composite load models, are capable of capturing the dynamic response of various end-use loads, namely induction motor load as required per TPL-001-4.[61] The NERC Load Modeling Task Force[62] (LMTF) is supporting the development and robust implementation of these models as well as the phased adoption of these models while gaining experience with the model in stability studies. LMTF has created a forum for utility planning engineers to share experiences and modeling efforts with other utility engineers, software developers, and subject matter experts.

End-use loads are rapidly changing due to energy efficiency standards and economics. “Grid friendly” loads that exhibit electrical characteristics that support the power grid during abnormal conditions (such as faults) are being replaced with electronically coupled loads controlled by converter technology. These electronically coupled loads may not exhibit this “grid friendly” characteristic; rather, they tend to have controls that maintain constant power consumption regardless of system voltage or frequency (with current limiters for protection purposes). The make-up and characteristics of end-use load technology are continually and rapidly evolving with the continued penetration of electronically coupled loads such as electric vehicles, plug-in electric hybrids, higher efficiency single-phase air conditioners, compact fluorescent lighting, LED lighting, LCD and LED televisions, variable-frequency drives, and electronically commutated motors.

NERC is also coordinating with the electric utility industry to understand the end-use load response needed for future reliability of the electric grid such that the BPS maintains stable equilibrium for major grid events. Preliminary studies have developed approaches for the “ideal” response of large-power electronic (electronically coupled) loads, such as electric vehicle chargers. In addition, NERC has been a contributor to the development of IEEE 1547,[63] particularly with respect to sharing BPS reliability perspectives and the impact that aggregated DERs can have on BPS performance.

Distributed Energy Resource Modeling

As the penetration of DERs continues to increase across the North American BPS, it becomes increasingly important to ensure that steady-state and dynamic models are able to sufficiently represent the individual or aggregate response of DERs for planning and operations purposes. The NERC Essential Reliability Services Working Group (ERSWG) and LMTF technical groups are exploring the modeling practices used for capturing these resources and any modeling improvements or recommended modeling practices for the electric utility industry to consider. While the industry is still learning much from areas with high penetration of DERs, including international experience, NERC supports information sharing and proactive exploration of the tools, models, and practices to

[59] NERC Phase 2 Case Quality Metrics
[60] NERC Case Metrics - 2015 Summer Base Case Quality Assessment; Phase I - Powerflow and Dynamics Case Quality Metrics
[61] NERC Standard TPL-001-4 -- Transmission System Planning Performance Requirements
[62] NERC Load Modeling Task Force
[63] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

help ensure reliability of the BPS moving forward. The ERSWG and LMTF are preparing technical materials developed by these industry stakeholder groups to share with the industry.

Reactive Power Requirements for Nonsynchronous Generation: FERC Order 827

FERC issued Order No. 827[64] on June 16, 2016, eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA). While some ISOs have reactive power standards for variable energy resources (VERs), FERC Order 827 states that all new interconnecting nonsynchronous generators will be required to provide reactive power at the "high-side of the generator substation as a condition of interconnection." FERC found that, due to technological advancements, the cost of providing reactive power no longer creates an obstacle to wind power development, and this decline in cost results in the current exemptions being "unjust, unreasonable, and unduly discriminatory and preferential." Key items for reliability addressed by FERC in its order[65] include:

- **Power Factor Range:** All newly interconnecting nonsynchronous generators must "design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis."
- **Point of Measurement:** Order 827 specifies the point of measurement for reactive power as the high-side of the generator substation**.** To clarify this location, the Commission states: "As an example, the generator substation would be the substation for a wind generator that separates the low-voltage collector system from the higher voltage elements of the Interconnection Customer Interconnection Facilities that bring the generator's energy to the Point of Interconnection."
- **Dynamic Reactive Power Capability Requirements:** Order 827 states that reactive power capability can be achieved by "systems using a combination of dynamic capability from the inverters plus static reactive power devices to make up for losses." This gives the Generator Owner flexibility to "[u]se static reactive power devices to make up for losses that occur between the inverters and the high-side of the of the generator substation, so long as the generators maintain 0.95 leading to 0.95 lagging dynamic reactive power capability at the high-side of the generator substation."
- **Real Power Output Threshold:** All newly interconnecting nonsynchronous generation must meet the reactive power requirements at all real power output levels. FERC provided an example of a 100 MW generator required to provide 33 MVAR at 100 MW output and 3.3 MVAR at 10 MW output. This essentially is a triangle-shaped capability curve based on the amount of active power being delivered at the point of measurement.

NERC is developing technical guidance to support Order 827, and will include this material as part of the *Reliability Guideline on Reactive Power Planning* currently being developed by the System Analysis and Modeling Subcommittee under the NERC Planning Committee.

[64] Federal Energy Regulatory Commission, Order No. 872, 16 June 2016
[65] NERC provided comments on the Notice of Proposed Rulemaking (NOPR) preceding this Final Rule.

System Restoration

Past NERC assessments have identified blackstart units as a potentially emerging issue as more conventional generation type units that have traditionally provided blackstart capability are retiring than are being built across the system. Blackstart units are generally smaller in output and are essential towards the implementation of system restoration plans that allow sections of the grid to return to service following a disturbance. As the determination of total installed capacity for a reserve margin calculation make no distinction between generation types, having fewer blackstart units in an area would have little to no impact on this deterministic resource adequacy metric. However, a large reduction in these units could significantly extend the duration of a blackout or otherwise limit a localized effort to mitigate immediate power quality issues.

Additionally, as many new, variable, and decentralized resources are installed, there is increasing difficulty with providing stable communication between these generating units and control rooms. Since a majority of wind and solar units generate the maximum energy possible at any given moment, a growing amount of generation without controllable outputs and ability to respond to system needs further complicates maintaining system resiliency. With the retirement of these conventional units, transmission owners and other applicable registered entities should review their individual needs to restore the interconnection and maintaining system reliability.

Practice and functionality for using renewables for system restoration and blackstart requirements are still at early stages of research and development. There are two approaches being considered for using VERs in system restoration: grid-forming and grid-following. This restoration research is currently focused on using the variable resources for grid-following. The likely outcome of the research will be to maintain the top-down restoration approach of energizing the high-voltage/100kV system using conventional generation and then using the VERs primarily to aid in island balancing and frequency regulation. There are challenges with using variable renewables for restoration; these resources are dependent on their energy inputs (i.e., sunlight, wind) being available during system restoration, and today's utility-scale, commercially available wind or solar PV resources were not specified and tested with the ability to start or run into a black system in mind. Thus, for existing wind and solar PV resources to participate in system restoration, they currently must follow and coordinate with a grid voltage and frequency that has been set by a synchronous generation resource. Viable, large-scale capability for blackstart with wind and solar PV are possible if this is a desired feature, but are several years away from commercial availability.

NERC's *2012 LTRA*[66] identified PJM as one area that had experienced a recent downward shift in blackstart-capable units. To review their own needs more thoroughly, PJM initiated the System Restoration Strategy Task Force (SRSTF)[67] to examine the current system restoration planning process. PJM did this to determine its viability and efficiency moving forward and to recommend any changes to any associated procurement, cost allocation, and compensation methods for system restoration. The task force recommended a number of changes to the existing rules for blackstart generation and the identification of critical load. It also developed the *PJM RTO Wide Five-Year Selection Process Black Start RFP*. The RTO-wide RFP is issued every five years and any unit that is interested in providing blackstart service can offer in to PJM's market. PJM would then review the existing blackstart units along with the new units offering into the RFP and optimize blackstart generation throughout the RTO.[68]

Reactive Power Supporting Devices

There are two components to the power supplied by conventional electric generators: real power and reactive power. Real power capacity performs the work of lighting, heating, cooling, and operating motors for a variety of uses, and can be replaced either locally or very remotely. This is a characteristic distinctive to real power since it can travel long distances via the BPS without losing effectiveness. However, the reactive power necessary to support BPS voltage, and to avoid collapse as real power flows across the BPS, has to be provided locally.

[66] NERC 2012 Long-Term Reliability Assessment
[67] System Restoration Strategy Task Force
[68] PJM Black Start / System Restoration; presentation October 5, 2015

Reactive generators will increasingly be utilized to replace dynamic voltage support lost from conventional retirements. These include SVCs; static synchronous compensators (STATCOMs); other electronic flexible alternating current transmission system devices; and synchronous condensers, which are large motors configured to provide voltage support. Low-voltage ride-through capability and effective protection and control of the reactive devices are included in minimum BPS reliability criteria, especially as reactive generator penetration increases. Current BPS inventory of these devices as time passes and undesirable events are caused or exacerbated by their inability for low voltage ride-through are worth developing and monitoring.

Advanced Capabilities of New Technology Resources

Deployment of new VERs, primarily wind and solar generation, has been rapid in recent years. The amount and rate that new additions are being made continues to increase yearly. Presently available technology on these resources offer the options to provide great flexibility for operation. These resources can change output power very quickly, which is extremely helpful to stabilize the frequency during disturbances and system restoration. The vast majority of new wind generation are Types 3 and 4 machines, which have capabilities to provide frequency response control. These controls have inertia-based and governor controls that provide complementary functionalities.

Inertia-based Controls

Most new Type 3 and 4 wind generators have built-in capabilities to provide fast frequency response. This response is based on temporarily using the stored inertial energy in the rotating mass of the wind turbine. These are often referred to as synthetic inertia controls and they respond rapidly for a frequency drop in a 1–10 second time frame. The primary function of this “fast frequency response” is to provide arresting power, shown in **Figure *5.1***. These controls use the inertial energy from the rotating wind turbine to supply power to the electric power system. Under undisturbed operation, the mechanical power input and electrical output are balanced. During a large under-frequency event when this wind generator control is enabled, the electrical output is greater than the mechanical input during the inertia response period, extracting inertial energy out of the rotor and causing the machine speed to decrease, thereby allowing the turbine to provide a very fast injection of additional power during the arresting phase of the frequency event. After the arresting period subsides and primary frequency response (PFR) action takes over, the mechanical energy must be recovered to bring the wind turbine back to the predisturbance rotational speed (and mechanical power). The turbine again reaches equilibrium when mechanical power input equals electrical power output. Because the turbine loses some efficiency during the time when it is slowed from its optimal operating points, the energy recovery during periods of moderate wind speed will typically to be on the order of twice or more arresting energy delivered. The control is progressively more effective at higher wind speeds, and the recovery energy is supplied by the wind (with little if any energy recovery period needed) when the turbine is operating at its rated output and wind speeds are sufficient to provide additional energy.

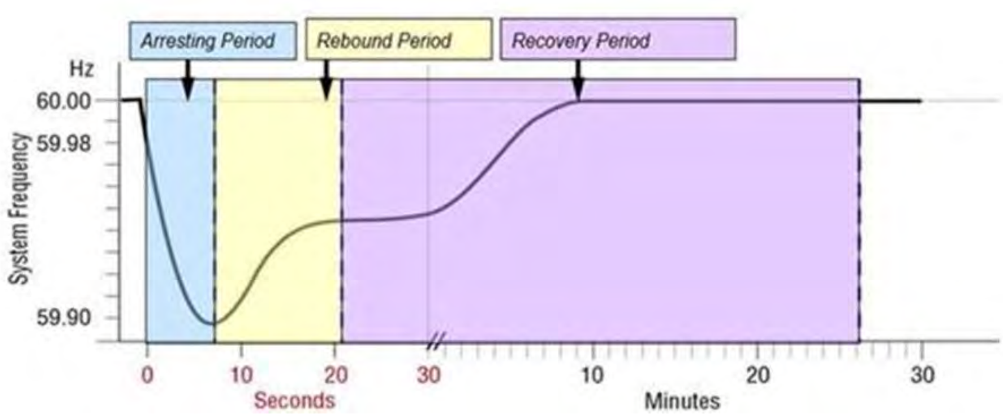


Figure 5.1: Time Frames of Frequency Response

Governor Control

Most existing and new Type 3 and 4 wind turbines, solar thermal, and new solar PV resources have the built-in control capability to provide PFR for both over frequency and under frequency events in the 5–60 second response time frame. This type of control is very similar to the governor control of synchronous thermal and hydro generation. It is often called governor control, which is unlike synchronous generation that reacts to and controls turbine speed (as a proxy for grid frequency), PFR relates the size of the resource lost to the resulting net change in system frequency. This is done during the period when stabilizing frequency is determined following the initiating system disturbance event. This is illustrated in **Figure 5.2**.

In **Figure 5.2**, results of an investigation of the EI show how governor controls could impact grid frequency. In **Figure 5.2**, a condition with a significant amount of wind generation is subjected to a very large loss of generation event. The cases (one with just governor response, in red, and one with both governor and inertial fast frequency response, in green) show a substantial improvement in the key metric, frequency nadir, over the reference case (in blue). In this case, the wind governors are deliberately set to respond with a similar speed as incumbent thermal resources. While this setting can be increased, having some fast-responding resources compared to others can result in unintended consequences with respect to system frequency. These frequency response time frames are set based on the response times of most combined-cycle units.

In order to provide the governor response for under frequency events, the wind or solar resource would have to be operating in a curtailed state to retain headroom for increasing its power output. This precurtailment is not required for wind or solar to respond to over frequency events or for the “synthetic inertia” response from wind turbines.

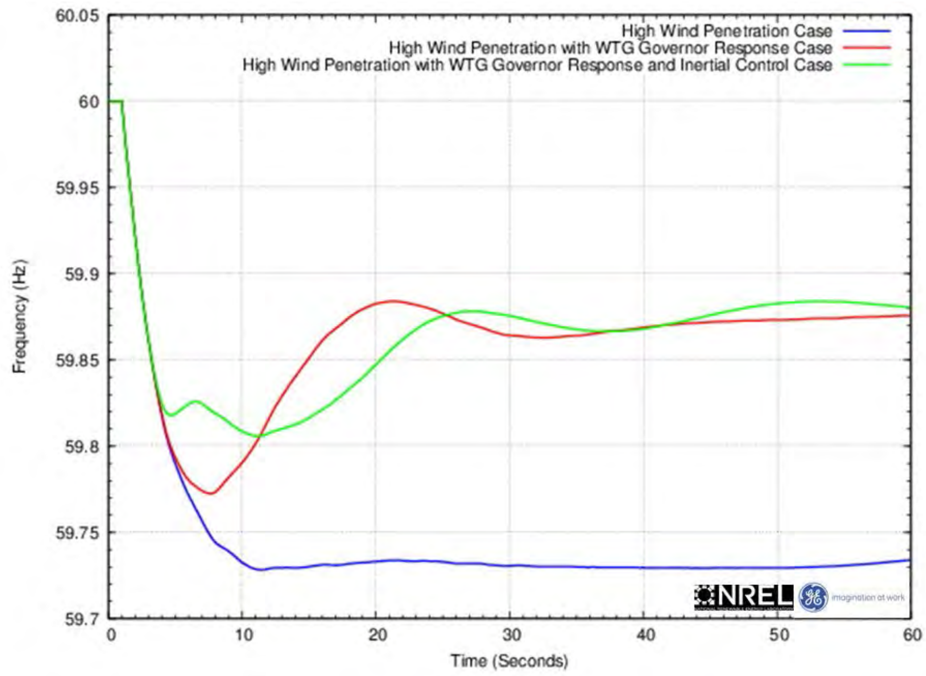


Figure 5.2: Illustration of Wind Turbine Frequency Controls[69]

[69] NREL: Eastern Frequency Response Study; May 2013

Solar Eclipse

North America will experience a total solar eclipse on August 21, 2017, similar to the total eclipse that passed over continental Europe, Nordic countries, and Great Britain in 2015. The path of the 2017 solar eclipse has been predicted by NASA[70] along with the affected levels of solar gradation outward from the path. A total solar eclipse is a precisely predictable event that causes substantial effects to wide-scale solar generation within a very short amount of time. The output generated by PV/solar systems will be either diminished or drastically reduced within the window of this event. Sudden widespread diminishing of solar irradiance may heavily affect areas with large amounts of utility scale PV energy installations or behind-the-meter DERs.

To further examine the potential impacts of this event, NERC will perform analysis and release a whitepaper summarizing the impact of the North American Solar Eclipse on the BPS in the first quarter of 2017. The assessment will leverage studies on past eclipse events to conduct an analysis on areas with high amounts of solar penetration along the path of the eclipse. NERC will identify any reliability concerns surrounding the BPS's ability to withstand/endure the event.

As the number of VERs in the power system increases, there is a greater dependency in the power system on intermittent energy sources. As a result, there is an emerging concern on maintaining a reliable and operable system during periodic astronomical events (i.e., solar eclipses, geomagnetic storms). For example, **Figure 5.3** below shows the path of the upcoming North American total solar eclipse of 2017 and the future total solar eclipse of 2024. Both eclipse routes move from the west to the east direction across North America. The map above shows that the August 21, 2017, eclipse proceeds across the U.S.A. in southerly movement with first and last total eclipse observations occurring in Oregon and South Carolina respectively. The April 8, 2024, eclipse advances northerly; the total eclipse will be first viewable in Sinaloa, Mexico, and lastly visible in Newfoundland and Labrador, Canada. Although both eclipse events occur (over by 1:30 p.m.) before historical time of day peak periods, the effect of eclipses on the BPS will become more relevant as more variable generation is installed in the system. Future detailed studies and coordination may be needed to ensure the effect of astronomical events on the behavior of wide-area BPS facilities are predictable and maintainable.

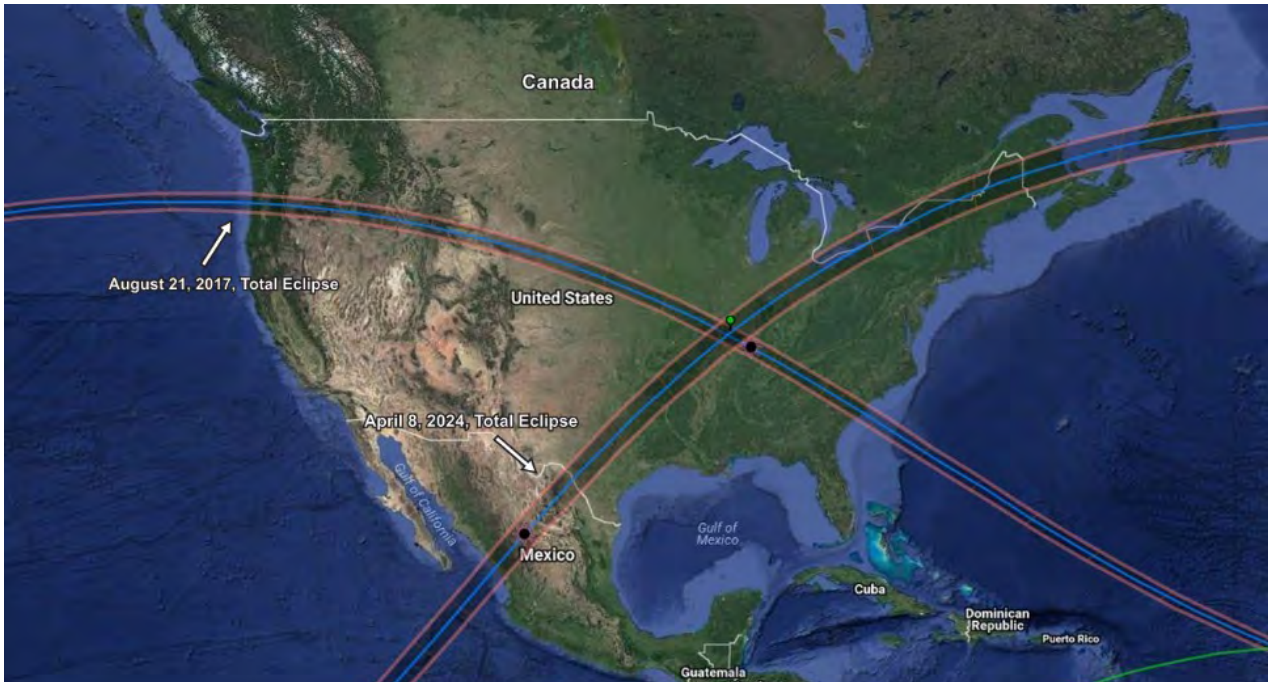


Figure 5.3: Solar Map—Projected Trajectory of the 2017 and 2024 Solar Eclipses

[70] Total Solar Eclipse of 2017 AUG 21; NASA.Gov

Chapter 6: Regional Overview

This chapter provides an overview of the results of this assessment for all Regional Entities by assessment area. Through joint efforts, NERC and the Reliability Assessment Subcommittee (RAS) built the process and analyses used for this assessment. In addition to the collection of data, NERC guides the creation of a set of narrative questions that seek to explain and clarify the potential risks to reliability that are identified throughout the BPS. Both the data and the narrative responses undergo a thorough peer review process within the RAS on an assessment area level and by the Regional Entities in a separate narrative question and review period. Presented here are highlights of the emerging issues and details by assessment area obtained through this comprehensive process.

Highlights of Emerging Issues

An intrinsic component of the peer-reviewed narratives is identifying emerging issues and potential risks to reliability that have been studied through additional assessments. Detailed here are the highlights of these emerging issues by assessment area.

FRCC

Weather events in the Gulf of Mexico could potentially have an impact on the availability and transportation of natural gas. However, dual-fuel capability, the increase of onshore (outside of Florida) gas resources, and a third gas pipeline currently under construction in central Florida (in service mid-2017) would mitigate natural gas transportation and supply issues in extreme weather events, such as hurricanes. FRCC's Fuel Reliability Working Group (FRWG) provides oversight of the Regional Entity fuel reliability forum that studies fuel availability and coordinates responses to fuel issues and emergencies.

MISO

Policy and changing generation trends continue to drive new potential risks to resource adequacy and will require continued transparency and vigilance to ensure long-term needs. MISO projects that reserve margins will continue to tighten over the next five years, which approaches the reserve margin requirement. Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in use of load modifying resources, such as behind-the-meter generation and demand response (DR). A number of large resources continue to feel economic pressure, which could lead to further plant retirements and drive the reserve margin lower.

MRO-Manitoba Hydro

There are potential new electricity export opportunities between Manitoba and Saskatchewan, which would likely require new transmission in western Manitoba. There is uncertainty as to the availability of local voltage support due to the potential shutdown of Brandon Unit 5 in 2020 in western Manitoba. It is expected that post-disturbance voltage will become an emerging concern in the period beyond 2025 depending on the timing of various projects. Plans to address this are under study.

MRO-SaskPower

The requirement to reduce emissions from thermal generating facilities will call for ongoing planning to ensure that proposed thermal generation retirements are successfully implemented. Saskatchewan is also working with the provincial and federal governments on emission regulations and agreements to confirm the schedule for retirements. Saskatchewan will have an increase in wind generation in the near- and long-term planning horizons. The inclusion of more intermittent resources may have operational impacts such as changes to net demand ramping variability that need to be studied to determine the power system effects on both Saskatchewan and neighboring jurisdictions.

NPCC-Maritimes

The Maritimes Area has begun tracking the ramp rate variability trend but does not yet have enough years of data for the area as a whole to identify any trends. Given the essentially flat load growth and small degree of anticipated variable energy resource (VER) installations, little change in either ramp rates or the area's resource mix is expected to occur for the duration of the LTRA assessment period. The maximum net demand ramping variability 1 hour up, 1 hour down, 3 hours up, and 3 hours down values for two historical years of 2014 and 2015 and a future year of 2020 were calculated along with the percentage contributions of VERs versus the loads. The majority of the maximums occurred during the late fall shoulder and winter peak seasons

NPCC-New England

Solar PV resources constitute the largest segment of distributed generation resources throughout New England. The region has experienced significant growth in the development of PV resources over the past few years and continued growth of PV is anticipated. In order to determine what impacts future PV could have on the regional power grid, the ISO created a forecast of future PV. ISO-NE's solar forecast separates the PV into two categories: 1) Markets and 2) Behind-the-Meter. PV in the Markets category consists of resources participating in the forward capacity market and PV as energy-only generating assets that participate in the energy market. Behind-the-Meter PV comprises approximately two-thirds of the total PV capacity and is treated as a load reducer. ISO-NE has limited information on the characteristics of behind-the-meter PV resources. ISO-NE does not collect behind-the-meter PV metered data, but can estimate its operational characteristics by using available historical PV production data along with total installed nameplate capacity. The total peak load reduction value of all PV in New England amounted to 588 MW in 2016 and it is forecasted to grow to 964 MW by 2021 and to 1,127 MW by 2026. These summer peak load reduction values are calculated as a percentage of ac nameplate. The percentages, which include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day, decrease from 40 percent of nameplate in 2015 to about 34 percent in 2026.

The ISO surveys Distribution Owners several times a year to determine the historical installations of PV and other types of distributed generation. The ISO annually projects PV installations by state and distributes them by dispatch zone. The forecast is based on state policies and reflects inputs from stakeholders. With the exception of PV, distributed generation is growing slowly and is accounted for within the ISO's demand forecast. The ISO is currently conducting scenario analyses that reflect large scale development of PV. These long-term planning studies, scheduled for completion in 2017, will assess the potential impacts on operating reserves, ramping, and regulations.

NPCC-New York

On January 25, 2016, the New York State Department of Public Service Staff (DPS) issued a whitepaper outlining its recommendations to the NYSPSC for implementing the state's Clean Energy Standard (CES).[71] The CES is intended to increase the amount of renewable energy generation in New York State to 50 percent of total generation by 2030 while retaining upstate nuclear power plants in support of the state's carbon dioxide emissions reduction goals.

The current solar integration study concluded that the BPS can reliably manage (over the five-minute time horizon) the increase in net load variability associated with the solar PV and wind penetration levels up to 4,500 MW wind and 9,000 MW solar PV. The solar study also concluded that the large-scale implementation of behind-the-meter solar PV will impact NYISO's load profile and associated system operations. Also, the lack of frequency and voltage ride-through requirements for solar PV facilities could worsen system contingencies when solar PV deactivates in response to frequency and voltage excursions

[71] New York Department of Public Service: Staff White Paper on Clean Energy Standard; January 2016

New York only determines an annual installed reserve margin (IRM) to meet a one-day-in-ten loss of load expectation (LOLE). Estimating the impact of the above-referenced issues on the IRM is difficult due to so many different input variables that would increase or decrease the margins. However, the addition of intermittent resources, such as solar and wind in the amounts proposed by certain initiatives, would have the tendency to increase the IRM requirements over time.

NPCC-Ontario

With the growth in distributed generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected VER and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

The introduction of VERs (e.g., solar and wind), the removal of flexible generation (coal), and lower demand and limitations in operational flexibility of gas and hydro resources have added new challenges to maintaining a reliable system. The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation, and additional grid voltage control. It is important that the supply mix remains robust in meeting industry planning standards, flexible to meet the ever-changing demands of system operations, and balanced to manage inherent risks (e.g., fuel security and critical infrastructure needs). To that end, the IESO has launched an initiative to augment resource flexibility and issued a Request for Information for additional regulation service in June 2016. The IESO has an energy storage pilot program underway to test the capability of storage technologies to provide grid services as well. Activities are also underway with transmitters to plan and install additional dynamic and static voltage control devices to help with voltage control.

Increasing amounts of VERs and relatively flat demand levels have contributed to a rise in surplus baseload generation (SBG) in Ontario. Over the next few years, more VERs are expected, but the effects on SBG will be tempered by the impact of the planned nuclear refurbishments and retirements. The IESO has mechanisms in place to manage SBG, including economic exports, wind and solar dispatch, and nuclear maneuvers or shutdowns.

NPCC-Québec

While technical developments in recent years have contributed to build a more reliable system, sustainable system reliability may be challenged by emerging issues, such as potential operational issues due to the changing resource mix. In the Québec area, wind generation capacity has increased by 2,500 MW over the last five years, but the area’s total installed capacity is still mainly composed of large reservoir hydro complexes (more than 90 percent) that can react quickly to adjust their generation output and meet the sharp changes in electricity net demand. The forecasted change to resource mix is not expected to have any influence on the ramp rate trends or any other reliability issue.

PJM

PJM has experienced some thermal overload problems during light load conditions with relatively high wind generator output. PJM’s light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity at light load. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level, such as high wind output.

Interchange levels for the various PJM zones will reflect a statistical average of typical previous years’ interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. The flowgates ultimately used in the light load reliability analysis are determined by the following: running all contingencies maintained by PJM planning and monitoring all PJM market-monitored facilities and all BPS facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5, and P7. For NERC TPL P0, normal system conditions will also be studied.

SERC

With respect to MISO, a settlement agreement was reached between MISO, SPP, and the Joint Parties (TVA, SOCO, LG&E/KU, AECI and PowerSouth). The settlement agreement is now in effect (and superseded the ORCA on February 1, 2016) to reliably manage the magnitude of power transfers between MISO South and Midwest. The settlement agreement limits transfers between MISO-South and MISO-Midwest to 2,500 MW and between MISO-Midwest to MISO-South to 3,000 MW in order to limit reliability impacts on neighboring systems. The increase in flow from 1,000 to 2,500/3,000 MW represents a new operating condition that has been studied and experienced under certain historical operating conditions. However, this is a significant change that will be closely monitored in operations for adverse reliability impacts. Although a settlement agreement is in place, SERC is committed to ensuring reliability of the region and the interconnection. The region implemented a Joint Loop flow study initiative with market and nonmarket entities to recreate and study loop flows within the area. The purpose of these studies are to ensure there are not potential IROL conditions that can lead to cascading, separation, or blackout conditions

SPP

SPP, along with other joint parties in the Region, and MISO are currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA).[72] On March 1, 2015, SPP and MISO began using Market-to-Market mechanisms to more efficiently and economically control congestion on SPP and MISO flowgates, in which both markets have a significant impact. During congestion on an SPP market-to-market flowgate, SPP will initiate the market-to-market process, and SPP and MISO will coordinate through an iterative process to identify and dispatch the most cost-effective generation between the two markets to relieve the congestion.

Texas RE-ERCOT

The Texas panhandle region is currently experiencing significantly more wind generation developer interest than what was initially planned for the area. ERCOT and Texas-RE are conducting a study while participating in a recent NERC pilot project related to ramping issues associated with high levels of VERs. In addition, ERCOT is performing steady state, dynamic, and short-circuit assessments to identify weak system areas and in particular to assess the reliability impacts in areas with high renewable penetrations. The assessment area is also projecting potential high increases in small distributed generation additions, such as rooftop solar. ERCOT is accelerating its efforts to more accurately map distributed energy resources (DERs) to the transmission grid.

WECC

Load-serving entities historically experience two rapid increases in customer demand: early morning and late afternoon. These rapid changes were typically balanced by increased hydroelectric and thermal generation. However, with greater generation contribution of intermittent resources, hydro and thermal units are required to follow larger daily demand fluctuations. The CA/MX subregion is seeing a large increase in distributed resources. There is currently about 4,300 MW of rooftop solar installed in the Western Interconnection with about 4,000 MW of that total installed in the CA/MX subregion. By 2026, that total is expected to increase to over 12,000 MW in the interconnection with over 11,000 MW installed in the CA/MX subregion. Due to the importance of hydro generation from the northwest, WECC monitors hydro conditions in that region. Under the Pacific Northwest Coordination Agreement, entities within the Northwest PowerPool have the obligation to coordinate the operations and long-term planning for the northwest Hydro system. WECC relies on their obligation and expertise to monitor and manage NW hydro issues.

[72] Operations Reliability Coordination Agreement; June 2013

California is continually working to coordinate the integration of VERs. The California ISO's energy imbalance market (EIM) provides a way to share energy reserves and renewable energy through a real-time energy market. The EIM operates in parts of California, Nevada, Utah, Idaho, Washington, Oregon, and Wyoming, and will expand into parts of Arizona in 2016. The ability to dispatch resources throughout the Western Interconnection has increased the flexibility needed to incorporate VERs into the grid.

Probability-Based Resource Adequacy Assessment

NERC recognizes that a changing resource mix with significant increases in energy-limited resources, changes in off-peak demand, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment as well as other ongoing analyses that will provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes. Historically, NERC has gauged resource adequacy through planning reserve margins, which are deterministic assessment metrics. Planning reserve margins are a measure of available capacity over and above the capacity needed to meet normal (50/50) forecast peak demand.[73, 74]

Background

In 2010, the Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) concluded that existing reliability models could be used to develop one common composite generation and transmission assessment. The task force also noted the importance of having complete coverage of the North American BPS as well as the elimination of overlaps. As this premise is already adopted and executed annually in the LTRA, the approach for the probabilistic assessment follows suit. The assessment areas (i.e., Regions, Planning Coordinators (PCs), independent system operators (ISOs), and regional transmission organizations (RTOs)) used for this assessment are identical to those used for the LTRA.

NERC produced a series of probabilistic assessment reports conducted by the Regions and assessment areas, covering all of the NERC Assessment Areas.

In this effort to improve NERC's continuing probabilistic and deterministic assessments, the Probabilistic Assessment Improvement Task Force[1] (PAITF) was formed in May, 2015, from members of the Planning Committee (PC), the Reliability Assessment Subcommittee (RAS), and selected observers from industry. Its purpose is to support the identification of improvement opportunities for NERC's Long-Term Reliability Assessment and complementary probabilistic analysis.

PAITTF has developed two reports. The first is the NERC Probabilistic Assessment Improvement Plan report, published in December 2015. This report provided possible recommendations by PAITF based on recent LTRA key findings for NERC core and proposed coordinated special probabilistic assessment reports. The second report was the NERC Technical Guideline document published in August, 2016. This report provided detailed probabilistic modeling guidelines and technical recommendations that serve as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy.

[73] NERC Reliability Assessments
[74] NERC Probabilistic Assessment Improvement Task Force

In the development of the *NERC 2016 Probabilistic Assessment*, NERC RAS and RAS-ProbA team implemented the following main PAITF technical guideline recommendations:

- Regions and assessment areas calculate monthly resource adequacy metrics. As resource and demand characteristics change over time, annual loss of load may start accruing during historically off-peak months. Therefore, the monthly aggregation of these metrics [loss of load hours (LOLH) and expected unserved energy (EUE)] will better inform industry of potential resource adequacy risks throughout the year.

- Assessment areas performed sensitivity modeling within the core probabilistic assessment framework. The NERC RAS identified the variable data elements relevant to each sensitivity model. NERC, with input from the RAS, ERO-RAPA, and the Planning Committee (PC), identified the Sensitivity Case to be an increase in load growth for the 2016 core probabilistic assessment. The purpose of this Sensitivity Case is to demonstrate the robustness of the loss of load measures:
  - Increase on-peak demand by two percent in the second study year, 2018, and by four percent in the fourth study year, 2020.
  - Increase MWh net energy by two percent in second study year, 2018, and by two percent in the fourth study year, 2020.

Summary statistic results of the forecast planning reserve margin, the forecast operable reserve margin,[75] annual and monthly LOLH and EUE measures for the Base Case and the Sensitivity Case, and high-level key findings are presented in the Assessment Area Granular Review section of the report.

Assessment Area Granular Review

Provided in more detail here are the more granular reviews of each assessment area's footprint, methods, assumptions used for this assessment, and additional information and data. This section includes dashboards that review both the deterministic and probabilistic data and results. Individually, these present a straightforward overview of the different assessment areas that make up the BPS and the variations between them.

[75] Forecast Operable Reserve Margin is defined as the ratio of anticipated resources derated by forced outage rates less on peak demand.

FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division members and 23 Member Services Division members composed of investor-owned utilities (IOUs), cooperative systems, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 47 registered entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.

Summary of Methods and Assumptions

Reference Margin Level
The FRCC Region utilizes the NERC 15 percent reference margin.

Load Forecast Method
Noncoincident, based on individual forecasts

Peak Season
Summer

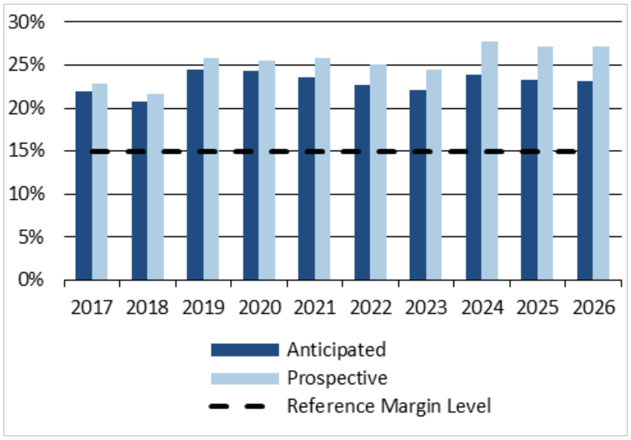
Planning Considerations for Wind Resources
No wind capacity

Planning Considerations for Solar Resources
Small amount of solar capacity; based on historical average at peak

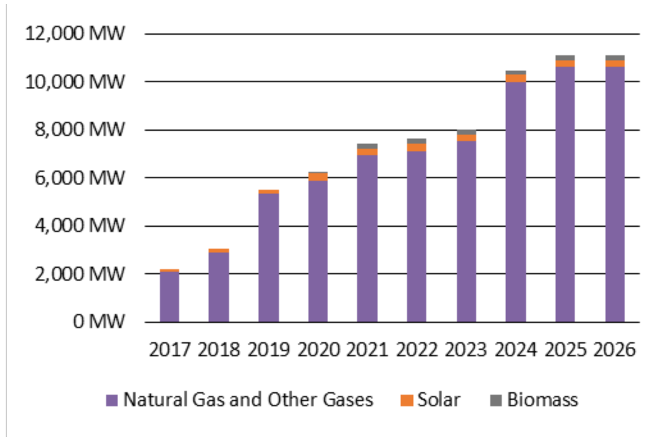
Footprint Changes
Region is the assessment area footprint; no recent changes

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	48,125	48,648	49,266	49,873	50,461	50,973	51,514	52,125	52,803	52,803
Demand Response	3,014	3,070	3,123	3,167	3,205	3,255	3,271	3,271	3,304	3,304
Net Internal Demand	45,111	45,578	46,143	46,706	47,256	47,718	48,243	48,854	49,499	49,499
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	55,015	55,019	57,442	58,088	58,379	58,551	58,916	60,533	60,994	60,976
Prospective	55,436	55,440	58,024	58,656	59,445	59,657	60,062	62,405	62,981	62,978
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	21.95%	20.71%	24.49%	24.37%	23.54%	22.70%	22.12%	23.91%	23.22%	23.19%
Prospective	22.89%	21.64%	25.75%	25.59%	25.79%	25.02%	24.50%	27.74%	27.24%	27.23%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** FRCC used the Tie Line and Generation Reliability (TIGER) program, which is based on the analytical method of recursive convolution for the computation of LOLH and EUE metrics.
- **Modeling:** The current modeling approach incorporates regional hourly load, generation data, forced outage rates, maintenance schedules, and monthly DR. Additionally, a load variation model was utilized that provided 500 variations of annual hourly load as an input into TIGER. FRCC was modeled as an isolated area with no interconnections with other areas and allowing only firm imports.
- **Results Trending:** 2018 was studied in both the 2014 and the 2016 ProbA to evaluate any changes or trends. The 2014 ProbA Base Case analysis resulted in an EUE of 0.070 MWh and an LOLH of 0.0002 hours per year. The results from the 2016 ProbA Base Case analysis showed a negligible decrease.
- **Probabilistic vs. Deterministic Reserve Margin Results:** There are no differences between the reserve margin reported in the LTRA and ProbA Base Case.

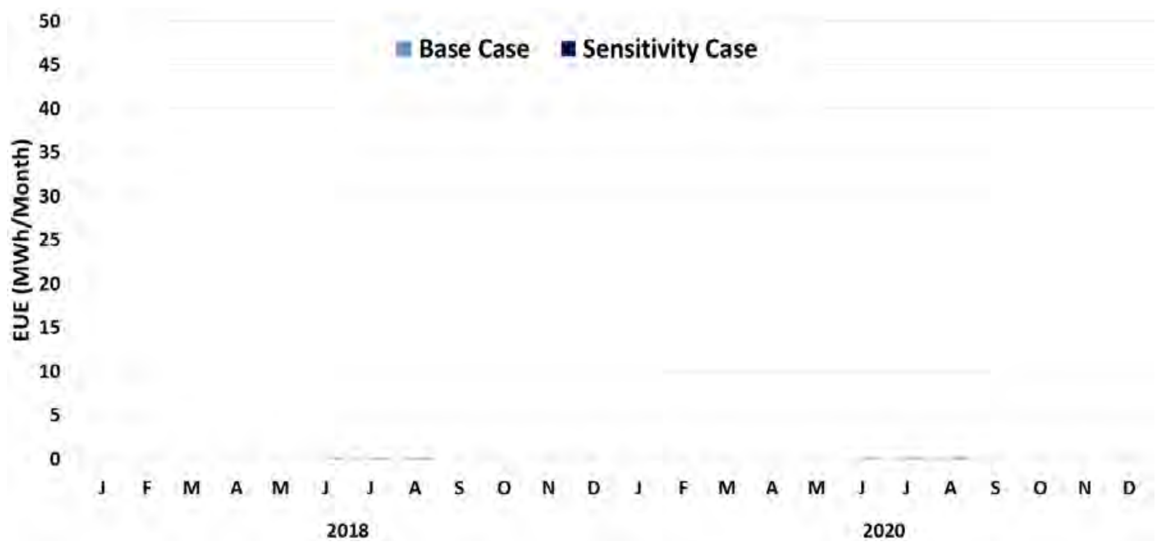
Base Case Study

Reserve margins for the study years are well above the NERC reference margin of 15 percent, resulting in low LOLH and EUE values. The EUE was 0.0013 MWh in 2018 and 0.0002 MWh in 2020. Projected loss of load only occurred during the summer season.

Sensitivity Case Study

With the increase of load in the Sensitivity Case, reserve margins remain above the NERC reference margin of 15 percent, and the EUE increased slightly from the Base Case to 0.0493 MWh in 2018 and 0.0333 MWh in 2020. Similar to the Base Case, a nonzero loss of load values are projected only during the summer season with highest values in August.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	20.7	24.4	18.2	19.3
Prospective	21.6	25.6	19.1	20.4
Reference	15.0	15.0	15.0	15.0
ProbA Forecast Planning	20.7	24.4	18.2	19.3
ProbA Forecast Operable	15.8	19.4	13.4	14.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.0013	0.0002	0.0493	0.0333
EUE (ppm)	0.0000	0.0000	0.0000	0.0000
LOLH (hours/year)	0.0000	0.0000	0.0002	0.0001



Planning Reserve Margins, Demand

FRCC has a reliability criterion of a 15 percent minimum regional total reserve margin based on firm load. FRCC reserve margin calculations include merchant plant capacity that is under firm contract to load-serving entities. FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and demand-side management (DSM) resources on an annual basis to ensure that the regional reserve margin requirement is projected to be satisfied. The three Florida Investor Owned Utilities, Florida Power & Light Company (FPL), Duke Energy Florida (DEF), and Tampa Electric Company (TEC) are utilizing, along with other reliability criteria, a 20 percent minimum total reserve margin planning criterion consistent with a voluntary stipulation agreed to by the Florida Public Service Commission (FPSC).[76] Other utilities employ a 15 percent to 18 percent minimum total reserve margin planning criterion.[77] Based on the expected load and generation capacity, all projected reserve margins are above the NERC Reference Margin Level of 15 percent for the FRCC assessment area with FRCC reserve margins remaining above 20 percent for all seasons during the assessment period.

[76] Docket No. 981890-EU Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida, Order No. PSC-99-2507-S-EU, issued December 22, 1999 (http://www.psc.state.fl.us/library/Orders/99/15628-99.pdf)
[77] Florida Administrative Code Rule 25-6.035 Adequacy of Resources (https://www.flrules.org/gateway/ruleno.asp?id=25-6.035)

FRCC continues to project growth in peak load, but the projected growth is less than in the previous forecast. The net energy for load (NEL) and summer peak demands are forecasted to be lower than in the previous forecasts. The current average annual growth rate for NEL is 0.8 percent per year compared to 1.1 percent per year in the previous forecast. Firm summer peak demand is expected to grow by 1.1 percent per year compared to 1.5 percent peak demand growth rate in the previous forecast. This is primarily due to more utilities starting to capture appliance efficiency in their load forecast models or using updated appliance efficiency assumptions. For firm winter peak demand, the average growth rate is now expected to be 1.0 percent per year compared to 0.9 percent per year in the previous forecast.

Demand-Side Management

The FRCC Region is projecting some decrease in the growth rate of utility program energy-efficiency due to two factors: (1) significant decreases in DSM cost-effectiveness caused by lower fuel costs, etc. and (2) increased impacts from federal and state energy-efficiency codes and standards (e.g., 2005 National Energy Policy Act, 2007 Energy Independence and Security Act). The impacts from these energy-efficiency codes and standards is lowering the potential for utility energy efficiency programs to lower demand and energy usage for appliances and equipment addressed by the codes and standards. However, these codes and standards are resulting in significant reductions in demand and energy that are accounted for in load forecasts. DR from interruptible and load management programs within FRCC is treated as a load-modifier and is projected to be relatively constant at approximately 6.4 percent of the summer and winter total peak demands for all years of the planning horizon.

The Florida Public Service Commission (FPSC) evaluates and revises its DSM goals every five years. New DSM Goals were set in 2014.[78] Because of diminished cost-effectiveness of DSM programs, and the fact that energy-efficiency codes and standards have lowered the potential for DSM programs, the FPSC set lower DSM Goals for Florida utilities than had been previously set in 2009. DR from interruptible and load management programs within FRCC is treated as a load-modifier, and is projected to be relatively constant at approximately 6.4 percent of the summer and winter total peak demands for all years of the planning horizon.

Generation

FRCC is projecting approximately 12,000 MW of summer and 12,262 MW of winter Tier 1 capacity to be added during the assessment period. The Tier 1 capacity will consist of mainly natural gas capacity with approximately 300 MW of firm solar (PV) and 180 MW of biomass. There are also 548 MW of planned uprates during the assessment period. The proposed generation additions are studied by the interconnecting Transmission Owner as well as by the FRCC Transmission Working Group (TWG) through FRCC's "Transmission Service and Generator Interconnection Service Request Assessment Area Deliverability Evaluation Process."[79]

Entities within FRCC have capacity transfers that have firm contracts available to be imported into the assessment area from SERC. There is approximately 830 MW of FRCC member-owned generation that is dynamically dispatched out of the SERC assessment area. These imports have firm transmission service to ensure deliverability into the FRCC assessment area. All firm on-peak capacity imports into the FRCC Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region with these capacity resources included in the calculation of the Region's Anticipated Reserve Margin. In addition, the interface owners between FRCC and SERC assessment areas meet quarterly to coordinate and perform joint studies to ensure the reliability and adequacy of the interface.

The FRCC assessment area is projecting approximately 3,900 MW of summer generation to be retired through the assessment period. These retirements will include approximately 2,400 MW of natural gas generation, 1000 MW of coal, and 500 MW of oil. Also, a 400 MW natural gas unit will be converted to a synchronous condenser to

[78] Order No. PSC-14-0696-FOF-EU (http://www.floridapsc.com/library/FILINGS/14/06758-14/06758-14.pdf)
[79] FRCC Reliability Evaluation Process For Generator and Transmission Service Requests; FRCC-MS-PL-054; 6-1-2016

provide voltage support. Based on the annual FRCC long-range study, FRCC is not anticipating any reliability impacts resulting from these unit retirements, which are studied as part of the FRCC long-range study process performed annually by the TWG to mitigate potential reliability impacts to the Grid and the FRCC reserve margin criteria.

FRCC is not anticipating any larger generator unavailability during system peak. All known scheduled generation outages in the long-term horizon are incorporated into the annual FRCC long-range study process to mitigate any potential reliability impacts to the BPS.

FRCC's Fuel Reliability Working Group (FRWG) provides oversight of the Regional fuel reliability forum that studies the fuel availability and coordinates responses to fuel issues and emergencies. FRCC is not expecting any long-term reliability impacts resulting from an increase mixture of natural-gas-fired generation.

Transmission and System Enhancements

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects are primarily related to expansion in order to serve forecasted growing demand and maintain the reliability of the BPS in the longer- term planning horizon.

The FRCC Region is not anticipating any additional reliability impacts resulting from potential environmental regulations. The State of Florida has not developed a renewable portfolio standard establishing target renewable thresholds. The 2013 MATS study performed by the FRCC's Transmission Working Group identified reliability impacts resulting from the retirement of two coal units at the same site. These units were granted an extension and will be able to run through 2018. These units will be replaced in the year 2018 by two gas-fired combined cycle units to maintain the reliability of the BPS within the FRCC Region. However, FRCC will continue to monitor the progress of the Clean Power Plan (CPP) to determine the potential impact to reliability once the current legal challenge has been resolved, which may result in changes in the timing and/or substance of the current CPP final rules.

Long-Term Reliability Issues

FRCC has not identified any long-term reliability issues. The FRCC Region performed an extreme weather (105 percent of peak) sensitivity scenario into its 2015 annual long-range planning study process to identify any potential reliability impacts to the BPS. The FRCC region is not expecting any reliability impacts during the shoulder periods. For the FRCC region, the shoulder periods are the spring and fall seasons. These seasons are studied in the operational horizon by the Operational Planning Working Group (OPWG) and by the TWG in the long-term horizon (off-peak cases) as part of the annual long range assessment. Additionally, FRCC has not identified any other emerging reliability issues. However, FRCC continues to monitor the possible impacts on the long-term reliability of the BPS from pending environmental legislations (CSAPR, NESHAP, RICE, MATS, and CPP).

MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit member-based organization. MISO administers wholesale electricity markets that provide customers with valued service, reliable, cost-effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Summary of Methods and Assumptions

Reference Margin Level
15.2 percent This increase is mainly driven by a process change within the LOLE study.

Load Forecast Method
Coincident

Peak Season
Summer

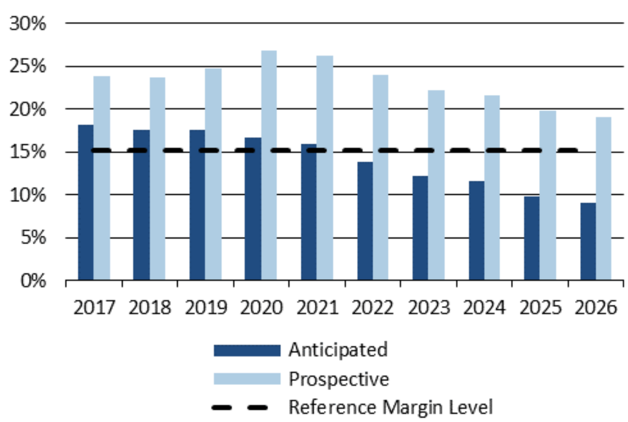
Planning Considerations for Wind Resources
Effective load-carrying capability (ELCC); varies by wind node

Planning Considerations for Solar Resources
No utility-scale solar resources in MISO

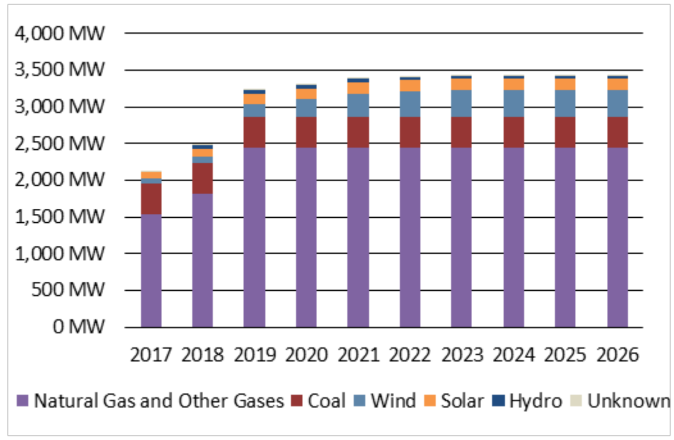
Footprint Changes
Minnesota is reporting under MISO this year

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	127,641	128,270	129,367	130,076	130,728	131,517	132,261	132,959	133,581	134,462
Demand Response	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827
Net Internal Demand	121,814	122,443	123,540	124,249	124,901	125,690	126,434	127,132	127,754	128,635
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	143,844	143,866	145,316	144,875	144,850	143,154	141,817	141,805	140,311	140,297
Prospective	150,779	151,474	154,063	157,614	157,590	155,722	154,517	154,506	153,062	153,047
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	18.09%	17.50%	17.63%	16.60%	15.97%	13.89%	12.17%	11.54%	9.83%	9.07%
Prospective	23.78%	23.71%	24.71%	26.85%	26.17%	23.89%	22.21%	21.53%	19.81%	18.98%
Reference Margin Level	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	1,640	3,836	4,651	6,862	7,890
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 local Balancing Authorities that are grouped into 10 local resource zones. For the ProbA, MISO utilized a multi-area modeling technique for the 10 local resource zones internal to MISO. Firm external imports and non-firm imports are also modeled. This multi-area modeling technique for resource zones and accompanying methodology has been thoroughly vetted through MISO's stakeholder process.

- **Modeling**: Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. In addition to the zone-specific import and export limits, a regional directional limit was modeled that limits the Midwest (local resource zones 1–7) to south (local resource zones 8–10) flow to 3,000 MWs and the south to Midwest to 2,500 MWs. The modeling of this limit is the main driver for the difference between the probabilistic and deterministic reserve margins. MISO utilizes unit specific outage, planning, and maintenance outage rates within the analysis based on five years of Generation Availability Data System (GADS) data. Modeling unit specific outage rates increases precision in the probabilistic analysis when compared to the utilization of class average outage rates.

- **Results Trending:** Previous results in the *2014 Probabilistic Assessment* resulted in 182.2 MWh EUE and 0.09 Hours per year LOLH. The results from this year's analysis resulted in a slight decrease for 2018 when compared to the analysis completed in the *2014 Probabilistic Assessment*.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The LTRA deterministic reserve margins decrease capacity that is constrained within MISO south due to the 2,500 MW limit which reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation produces an increase for the ProbA forecast planning reserve margin.

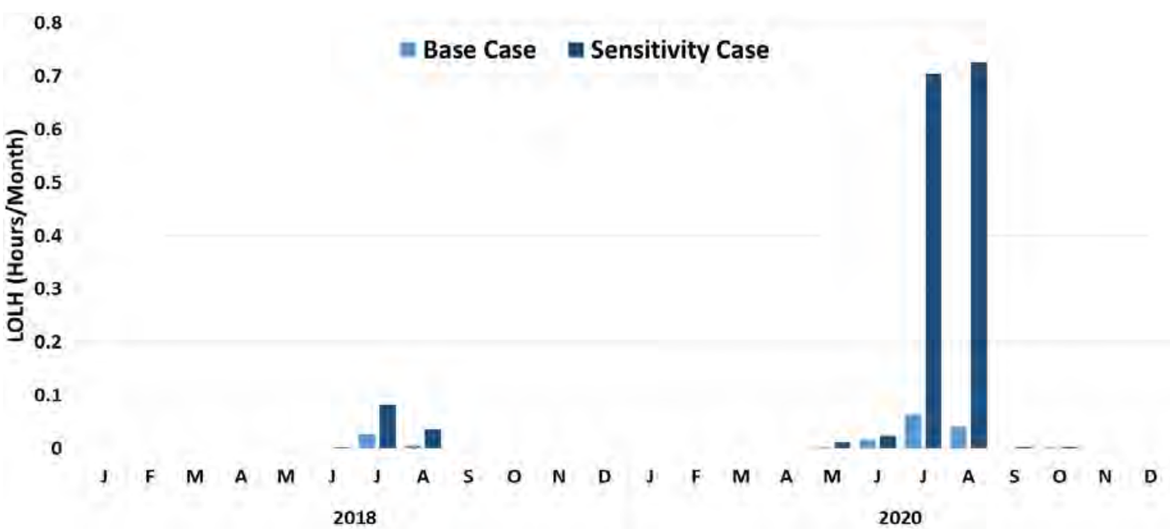
Base Case Study

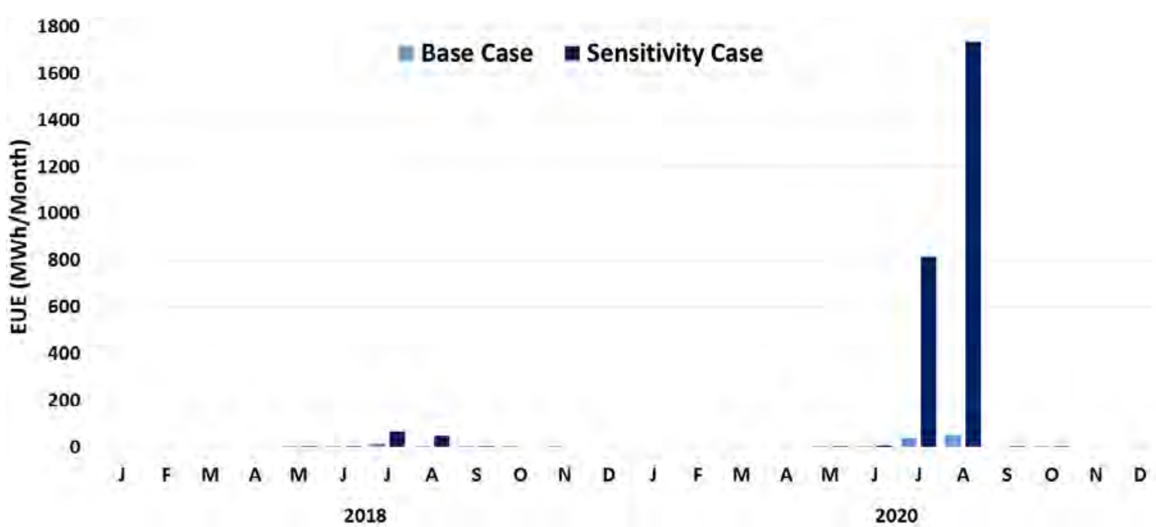
- The bulk of the EUE and LOLH are accumulated in the summer peaking months with some off-peak risk.
- Increases in loss of load statistics are expected with decreasing reserve margins.

Sensitivity Case Study

- The Sensitivity Case is a good proxy for increased retirement risk and/or increased load forecasts. The 2018 2 percent increase is equal to a 2,565 MW increase and the 2020 4 percent increase is equal to a 5,203 MW increase.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	17.5	16.6	-	-
Prospective	23.7	26.9	-	-
Reference	15.2	15.2	-	-
ProbA Forecast Planning	21.7	20.2	19.2	15.4
ProbA Forecast Operable	12.0	10.6	9.7	6.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	17.95	95.80	113.83	2565.70
EUE (ppm)	0.026	0.133	0.160	3.430
LOLH (hours/year)	0.033	0.125	0.119	1.474





Overview

MISO projects a regional surplus for the summer of 2017 with potential regional shortfall starting in 2018. These results show a potential regional short fall two years earlier than the *2015 MISO LTRA* results. These results are driven by a number of factors:

- A decrease in resources committed to serving MISO's load mainly by independent power producers (IPP).
- A decrease in load forecasts where the biggest drop was in Zone 6 (Indiana).
- The increase in committed resources (Tier 1) in Zone 7 (Michigan).
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their local clearing requirements or the amount of their local resource requirement (which must be contained within their boundaries).
- Several zones are short against their total zonal reserve requirement when only resources within their boundaries (or are contracted to serve their loads) are considered. However, those zones have sufficient import capability, and the MISO region has sufficient surplus capacity in others zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; MISO is engaged with stakeholders in a number of resource adequacy reforms to help rectify these later year's shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

- MISO projects that reserve margins will continue to tighten over the next five years and approach the reserve margin requirement.
- Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in use of Load Modifying Resources, such as behind-the-meter generation and DR.

The SPP settlement agreement has put in place a Regional Directional Transfer Limit replacing the ORCA operating limit. Specifically the Midwest (LRZs 1-7) to south (LRZs 8-10) flow is limited to 3,000 MWs and south to Midwest is limited to 2,500 MWs.[80]

This year marks the third iteration of the Organization of MISO States (OMS) MISO survey, which helps provide forward visibility into the resource adequacy position of the MISO region. The survey also helped identify resources that had a low certainty of being available for each planning year.

The LTRA results represent a point in time forecast, and MISO expects these figures will change significantly as future capacity plans are solidified by load-serving entities and States. For example, there are enough resources in Tier 2 and 3 to mitigate any long-term resource shortfalls.

MISO forecasts the coincident Total Internal Demand to peak at 127,607 MW during the 2017 summer season. This is a decrease of roughly 2,700 MWs from last year's projection for 2017. This decrease is mainly driven by load reductions in Zones 5 (Missouri) and aluminum smelter closures in Zone 6 (Indiana). MISO projects the

[80] MISO Presentation: SPP Settlement Update; October 2015

summer coincident peak demand to grow at an average annual rate of 0.6 percent, which is less than the growth rate from the 2015 assessment.

As a result of the OMS-MISO survey, resources with a low certainty of being available for the given year are more visible. This number is small in Years 1–3 and then ramps up in the future. The reductions of these low certainty resources are more than offset with Tier 2 and 3 resources and should not cause any resource adequacy issues. However, MISO continues to see a number of large resources, generally IPPs, that are "at-risk" for retirement due to economics. Local reliability issues could result with some of the unannounced retirements.

The annual MISO Transmission Expansion Plan (MTEP)[81] proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. As part of MTEP15, MISO staff recommends $2.75 billion of new transmission expansion through 2024, as described in Appendix A of the MTEP report,[82] to the MISO Board of Directors for review, approval, and subsequent construction.

The 345 new projects in MTEP15 Appendix A represent $2.75 billion[83] in transmission infrastructure investment and fall into the following four categories:

90 Baseline Reliability Projects (BRP) totaling $1.2 billion: BRPs are required to meet NERC reliability standards.

12 Generator Interconnection Projects (GIP) totaling $73.6 million: GIPs are required to reliably connect new generation to the transmission grid.

1 Market Efficiency Project (MEP) totaling $67.4 million: MEPs meet requirements for reduction in market congestion.

242 Other Projects totaling $1.38 billion: Other projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects.

MISO is working with stakeholders to create resource adequacy reforms to move to a seasonal construct. The seasonal construct would create a summer and a winter planning reserve margin requirement and seasonal resource parameters (on peak capacity, EFORd, etc.). The seasonal construct will better reflect the seasonality of the wind, solar, etc. and increase the visibility of reliability in the winter season.

[81] MISO Transmission Expansion Planning (MTEP)
[82] MISO Transmission Expansion Plan 2015
[83] The MTEP15 report and project totals reflect all project approvals during the MTEP15 cycle, including those approved on an out-of-cycle basis prior to December 2015.

MRO-Manitoba Hydro

Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 561,869 customers throughout Manitoba and natural gas service to 274,817 customers in various communities throughout southern Manitoba. The province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Summary of Methods and Assumptions

Reference Margin Level
The capacity criterion, as determined by Manitoba Hydro, requires a minimum 12 percent planning reserve margin, applied as the Reference Margin Level in this assessment.

Load Forecast Method
Coincident

Peak Season
Winter

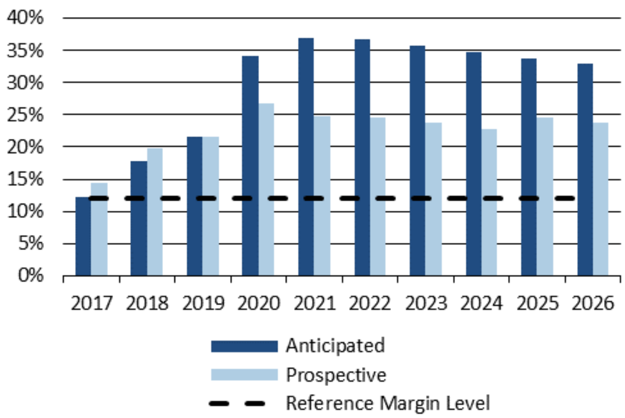
Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC) of 15.6 percent for the summer and 20 percent for the winter.

Planning Considerations for Solar Resources
No utility-scale solar resources

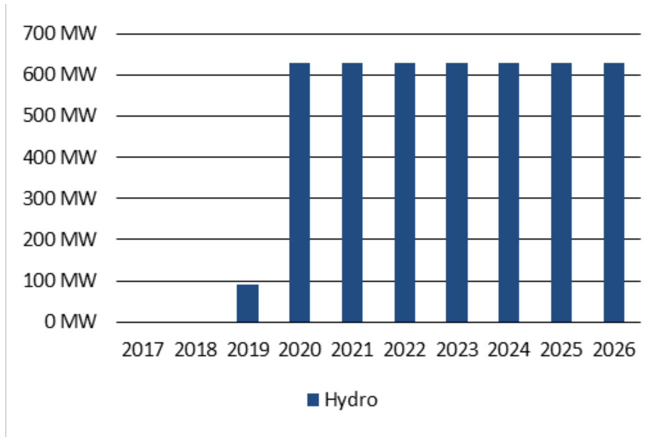
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	4,826	4,713	4,646	4,703	4,685	4,710	4,743	4,781	4,793	4,821
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,826	4,713	4,646	4,703	4,685	4,710	4,743	4,781	4,793	4,821
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	5,419	5,557	5,647	6,304	6,412	6,437	6,437	6,437	6,412	6,412
Prospective	5,526	5,649	5,646	5,961	5,844	5,869	5,869	5,869	5,969	5,969
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	12.29%	17.90%	21.53%	34.04%	36.86%	36.66%	35.72%	34.65%	33.79%	33.00%
Prospective	14.51%	19.86%	21.53%	26.75%	24.74%	24.61%	23.76%	22.77%	24.56%	23.82%
Reference Margin Level	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Manitoba Hydro system is a winter-peaking system, and the vast majority of its generating facilities are use-limited or energy-limited hydro units. The 2016 Manitoba Hydro probabilistic assessment was conducted using the Multi-Area Reliability Simulation (MARS) program. The data used in the MARS simulation model are consistent with the data reported in the *2016 LTRA* submittals from Manitoba Hydro to NERC.

- **Modeling Characteristics:** Manitoba Hydro and its neighboring systems are modeled as two areas consisting of Manitoba and the northwest part of MISO. Each of the two interconnected areas are modeled connected directly and the transmission between Manitoba and MISO is modeled with interface transfer limits. Three different types of resources are modeled for Manitoba Hydro system: hydro resources, thermal resources (including both coal and gas units), and intermittent wind resources. The 8,760 point hourly load records of a typical year were used to model the annual load curve shape. Load forecast uncertainty is modeled in both the Base and Sensitivity Cases. DR programs are modeled as a simple load modifier by reducing the peak load. Contractual obligations are modeled as load modifiers considering the contractual obligations of the power sales and purchase agreements.

- **Results trending:** The LOLH and EUE values obtained in the *2014 Probabilistic Assessment* are zero. The nonzero LOLH and EUE values are obtained for both the Base and Sensitivity cases in *2016 Probabilistic Assessment*. The slight increase in the reliability indices is mainly due to the changes in modeling assumptions. The following specific changes are made in 2016 assessment as compared to 2014 assessment: 1) Multiple flow conditions, including an extreme drought scenario, are modeled and the indices calculated are weighted averages of the indices obtained for different water conditions. 2) Increased standard deviation of the seven-step load forecast uncertainty from four percent to five percent.

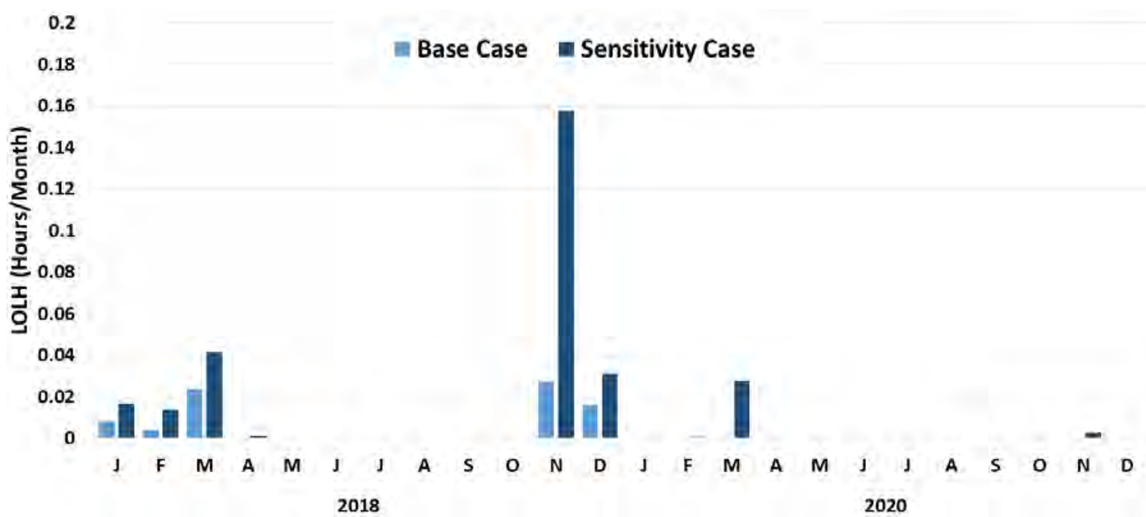
Base Case Study

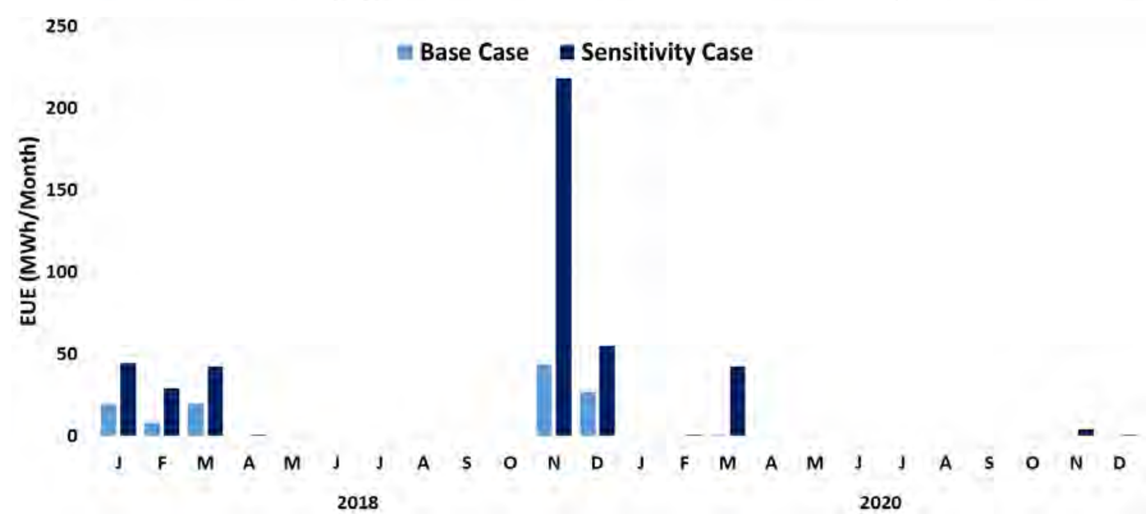
For 2018 Base Case, small values of EUE and LOLE are observed due to a relatively smaller reserve margin. For 2020 Base Case, the reserve margin is increased significantly due to the expected addition of a new generating station and therefore the LOLE and EUE are virtually zero. All loss of load events are in winter season and the highest contribution to loss of load is from the winter month of November.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	17.90	18.67	-	-
Prospective	19.86	30.15	-	-
Reference	12	12	12	12
ProbA Forecast Planning	13.7	22.9	11.4	18.2
ProbA Forecast Operable	11.0	20.4	8.8	15.8
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	117.06	0.24	389.88	47.27
EUE (ppm)	4.45	0.01	14.53	1.72
LOLH (hours/year)	0.0783	0.0001	0.2608	0.0304

Sensitivity Case Study

As expected, the reliability indices are increased in the Sensitivity Cases for both the 2018 and 2020 planning years, and all loss of load events are in winter season. Although the planning reserve margin drops below the reference value of 12 percent for a 2 percent increase in peak load, the EUE and LOLE are still small for 2018 planning year. The minor changes in the LOLE and EUE indices for 2020 planning year is mainly due to the decrease in reserve margin for a 4 percent increase in peak load. The highest contribution to the loss of load event is still from the winter month of November for 2018 while it is from the winter month of March for 2020 planning year.





Demand, Resources and Reserve Margins

Manitoba Hydro is projecting reserve margins above the Reference Margin Level during the assessment period.

Since the previous assessment, the demand forecast is projected to be 1.4 percent lower by 2025/26, and this is primarily attributable to an increase in the forecast of DSM activity. The forecast of DSM in 2025/26 is increasing from 516 MW forecast in the previous assessment to 685 MW in the current assessment. No changes were made to the load forecasting methodology from the last assessment period.

Energy efficiency and conservation savings are forecast higher than prior year's assessment due to enhancements to existing programs (e.g., increasing program incentives, adding alternative program delivery methods, or adding new measures to the program).

There have been no capacity additions in Manitoba since the *2015 LTRA*. The Keeyask Hydro Generating Station is now under construction and is considered a Tier 1 capacity addition. Manitoba Hydro is anticipating the first units of the 630 MW of net capacity addition from the Keeyask Hydro Generating Station would begin to come into service in late 2019. Brandon Unit 5, Manitoba Hydro's sole remaining coal-fired generating unit, is assumed to remain available until December 31, 2019, when it is considered to be an unconfirmed retirement. This potential retirement of Brandon Unit 5's approximately 95 MW of capacity is not expected to have an impact on reliability as other resources are expected to come into service at that time.

Manitoba Hydro has up to 925 MW of firm and/or expected capacity exports in the winter, up to 625 MW of firm and/or expected capacity imports in the winter, and up to 1,525 MW of firm and/or expected capacity exports in the summer. There are associated firm transmission reservations over the 10 year assessment period. Manitoba Hydro does not have any capacity imports during the summer. Manitoba Hydro does not have any capacity transactions beyond the contract terms. Included in the firm exports are up to 475 MW of firm contracts in relation to the 630 MW Keeyask generating station, which is anticipated to come into service around 2020.

Manitoba does not have a legislated renewable mandate, such as an RPS, and no legislation is currently anticipated.

MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a Provincial Crown Corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections.

Summary of Methods and Assumptions

Reference Margin Level

No change in Reference Margin Level since the *2015 LTRA*. The reserve margin for SaskPower's generation system must not fall below 11 percent of adjusted net demand. This percentage represents the amount of excess generation SaskPower will have after serving the highest projected load during the peak month.

Load Forecast Method

Coincident, 50/50 forecast

Peak Season

Winter

Planning Considerations for Wind Resources

10 percent of nameplate (summer); 20 percent of nameplate (winter)

Planning Considerations for Solar Resources

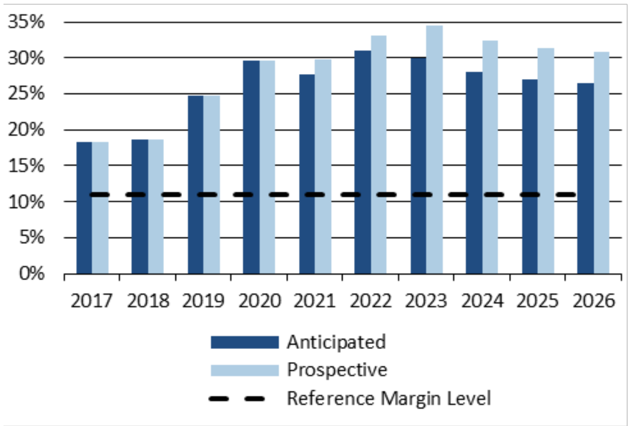
No utility-scale solar resources

Footprint Changes

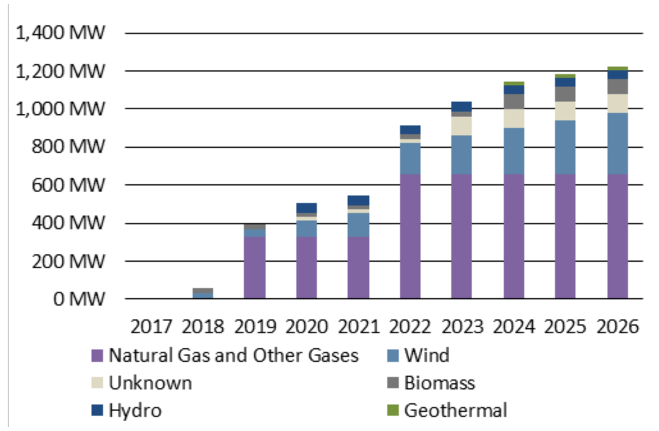
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	3,724	3,761	3,852	3,874	3,901	3,959	4,007	4,048	4,111	4,159
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,639	3,676	3,767	3,789	3,816	3,874	3,922	3,963	4,026	4,074
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	4,303	4,364	4,700	4,910	4,872	5,076	5,101	5,072	5,112	5,152
Prospective	4,303	4,364	4,700	4,910	4,950	5,156	5,276	5,247	5,287	5,327
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	18.24%	18.72%	24.76%	29.58%	27.67%	31.01%	30.04%	27.97%	26.96%	26.46%
Prospective	18.24%	18.72%	24.76%	29.58%	29.71%	33.07%	34.50%	32.38%	31.31%	30.75%
Reference Margin Level	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Saskatchewan is a winter-peaking area (December). The Saskatchewan Power Corporation (SaskPower) is the principal supplier of electricity in the province of Saskatchewan, Canada. SaskPower is a provincial Crown Corporation, which under the provincial legislation, is responsible for the reliability oversight of the Saskatchewan bulk electric system and is obligated to serve its domestic load.
- **Modeling Characteristics:** SaskPower utilized the Multi-Area Reliability Simulation (MARS) program for the purpose of this study. This reliability study is based on the DSM adjusted 50/50 load forecast.
- **Results Trending:** Since the *2014 Probabilistic Assessment*, the reported forecast reserve margin for year 2018 has gone down slightly from 20.6 percent to 17.8 percent mainly due to a change in the expansion sequence. As expected, EUE and LOLH have increased when compared to analysis completed in 2014.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Most of the data is consistent with the LTRA except the energy forecast and the expansion sequence, which has been updated to reflect the most recent projections.

Base Case Study

The major contribution to the 2018 LOLH and EUE is in the month of October (around 60 percent). There are maintenances scheduled to the largest coal and large natural gas units in that month. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

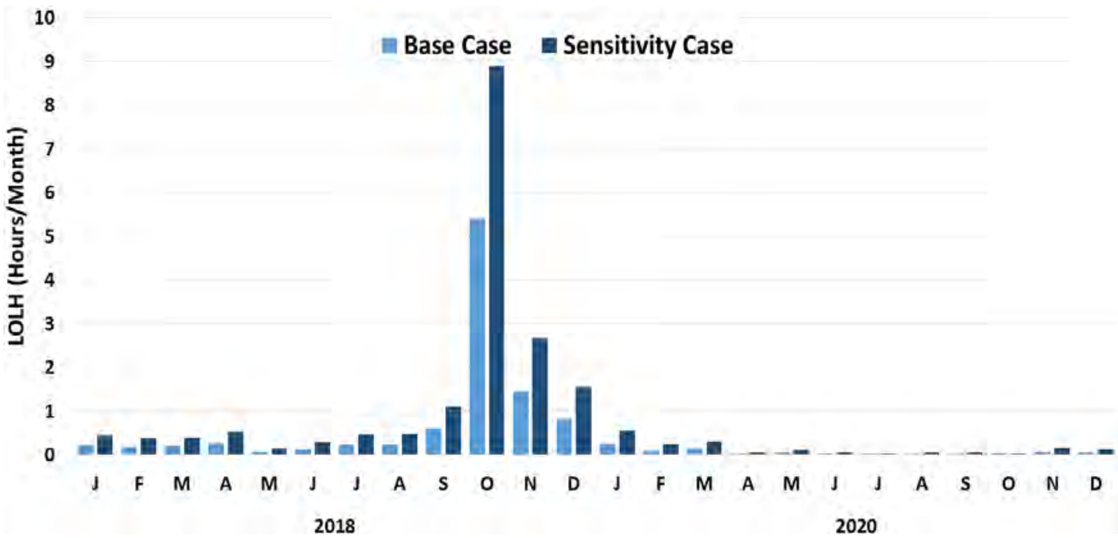
In the year of 2020, the LOLH and EUE are highest in January due to higher load.

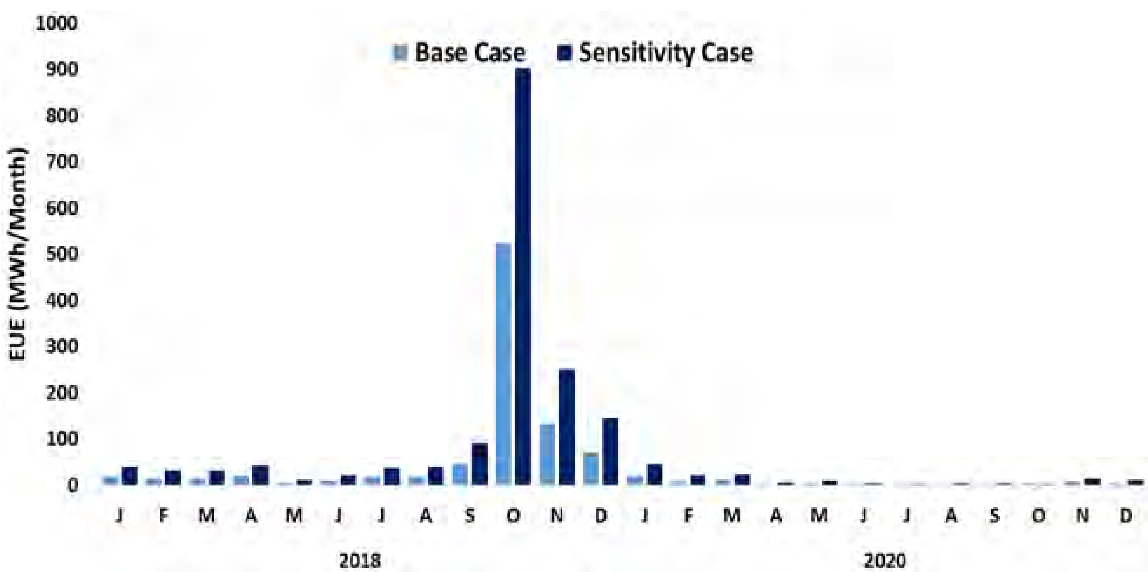
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	17.8	25.6	15.4	20.7
Prospective	17.8	25.6	15.4	20.7
Reference	11	11	11	11
ProbA Forecast Planning	17.8	25.6	15.4	20.7
ProbA Forecast Operable	14.6	22.6	12.3	17.7
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	893.6	65.5	1639.5	147.0
EUE (ppm)	36.16	2.56	65.05	5.64
LOLH (hours/year)	9.78	0.836	17.31	1.77

Sensitivity Case Study

A similar monthly trend is observed in the Sensitivity Case. As compared to the Base Case, the reserve margin has decreased from 17.8 percent to 15.4 percent and from 25.6 percent to 20.7 percent for year 2018 and 2020, respectively.

The effect of higher load growth is evident on the reliability metrics. EUE is almost doubled from the Base Case in both study years. EUE reported for Sensitivity Case is 1639.5 MWh/yr and 147 MWh/yr for the year 2018 and 2020, respectively.





Demand, Resources, and Planning Reserve Margins

Saskatchewan plans to meet projected load requirements with anticipated resources throughout the assessment period. Saskatchewan's Anticipated Reserve Margin exceeds the 11 percent Reference Margin Level for the assessment period.

Saskatchewan experiences peak demand in the winter. The average annual growth rate for total internal demand is 1.4 percent during the assessment period, which is slightly lower than last year's forecast (1.89 percent). The slight decrease is mainly caused by the deferral of oil pipeline projects. The growth is expected to be generally spread throughout the province. Saskatchewan is planning for a seven percent yearly average growth of energy efficiency and conservation programs, and DR programs are projected to remain unchanged.

In Saskatchewan, projected unit retirements for the assessment period include 174 MW of natural gas facilities, 11 MW of wind facilities, and two-139 MW coal facilities. There were 228 MW (nameplate) added in the Assessment area since the *2015 LTRA*. Throughout the assessment period, a total capacity of 2633 MW (nameplate) of Tier 1 resources is projected to come on-line. This total consists of 660 MW of natural gas, 1607 MW of wind, 120 MW of solar, 76 MW of biomass resources, 100 MW of flare gas resources, 20 MW of geothermal, and 50 MW of hydro resources.

For capacity transfers, Saskatchewan has a firm import contract for 25 MW until the spring of 2022. Saskatchewan also has a firm import of 100 MW from July 2020 until the end of the assessment period. There are no anticipated firm exports for the assessment period. Saskatchewan only imports and exports based on economics. Import also increases supply mix diversification for Saskatchewan.

Transmission Outlook and System Enhancements

Saskatchewan plans to invest in transmission infrastructure over the assessment period in order to maintain and enhance reliability. The related projects are dependent on load growth and include the construction of 918 km of new 138 kV and 230 kV transmission line. Saskatchewan is also adding a static VAR system in the South-Central Region of the province to help with voltage control in the area by the end of 2016.

Long-Term Reliability Issues

It is not expected that extreme weather events will impact long-term reliability in Saskatchewan; however, operation of the Saskatchewan system would be performed on a best-effort basis under extreme weather events. Demand would be offset by planning reserves and external markets. If necessary, operational measures include DR, interruptible load contracts, public appeals, and rotating outages.

Typically, a significant amount of unit maintenance (partial and total unit outage) is planned for the shoulder periods in Saskatchewan. If short-term reliability issues are identified during a shoulder period, unit maintenance will be rescheduled.

Saskatchewan does not expect any long-term reliability impacts resulting from fuel supply and/or transportation constraints. Fuel disruptions are minimized as much as possible by system design practices and Saskatchewan's diverse energy mix of resources. Coal resources have firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have firm transportation contracts with large natural gas storage facilities located within the province capable of supporting those contractual requirements. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long term hydrological conditions are monitored.

Essential Reliability Services

The Saskatchewan net demand ramping trend for historical years (2013, 2014, and 2015) shows a gradual increase by approximately five percent each year. Contribution of the VERs to the increase in ramp rate was, however, minimum as there has been no significant increase in VERs in the historical years in Saskatchewan. Projected 2016 ramp rates also show approximately a five percent increase from the historical years. Projected 2020 ramp rates show an increase by approximately 70 percent from the 2016 and historical year ramp rates.

Saskatchewan system inertia did not change significantly for the 2015, 2016, and 2018 years. There has not been a significant change in installed generation capacity in these years.

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island; as well as the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles, with a total population of 1.9 million people.

Summary of Methods and Assumptions

Reference Margin Level
20 percent

Load Forecast Method
Coincident; 50/50 forecast

Peak Season
Winter

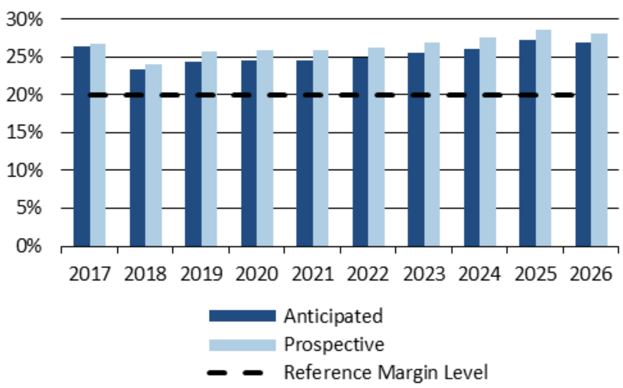
Planning Considerations for Wind Resources
Estimated capacity is derived from a combination of mandated capacity factors and reliability impacts.

Planning Considerations for Solar Resources
N/A

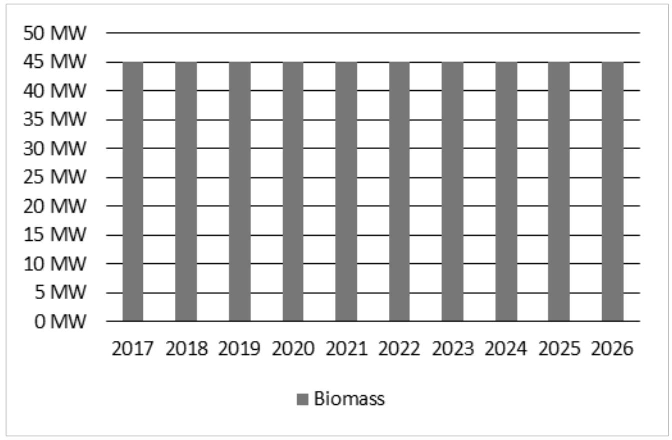
Footprint Changes
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	5,584	5,608	5,627	5,623	5,622	5,608	5,580	5,552	5,509	5,518
Demand Response	272	272	272	272	271	271	271	271	271	270
Net Internal Demand	5,312	5,336	5,355	5,351	5,350	5,336	5,309	5,281	5,238	5,248
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	6,716	6,585	6,661	6,661	6,661	6,661	6,661	6,661	6,661	6,655
Prospective	6,735	6,621	6,735	6,735	6,735	6,735	6,735	6,735	6,735	6,724
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	26.42%	23.40%	24.37%	24.47%	24.49%	24.82%	25.47%	26.13%	27.16%	26.81%
Prospective	26.79%	24.08%	25.77%	25.87%	25.89%	26.21%	26.88%	27.54%	28.59%	28.13%
Reference Margin Level	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The GE MARS model, developed by the NPCC CP-8 Working Group, was used for the following: demand uncertainty modeling, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (i.e., NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[84]

- **Results Trending:** The previous study, the *NERC RAS Probabilistic Assessment—NPCC Region*,[85] estimated an annual LOLH = 0.001 hours per year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 forecast 50/50 peak demand forecast is 262 MW greater in this assessment than reported in the previous assessment. This reflects increases in electric heating loads that were not quite offset by declines in industrial loads and demand shifting programs. Forecast capacity resources increased by 81 MW in the *2016 Probabilistic Assessment* as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments. Increased capacity resources, coupled with reliance on operating procedures and tie benefits, contribute to this result.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The Maritimes Area employs a reserve criterion of 20 percent of firm load. To relate the Maritimes Area reserve criterion of 20 percent to the NPCC resource adequacy criterion, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20 percent. The results showed that a Maritimes Area reserve of 20 percent corresponds to an LOLE of approximately 0.086 days per year.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in the *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment—NPCC Region*.[86]

[84] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[85] NERC RAS Probabilistic Assessment: NPCC Region; March 2015
[86] NPCC Library - Resource Adequacy

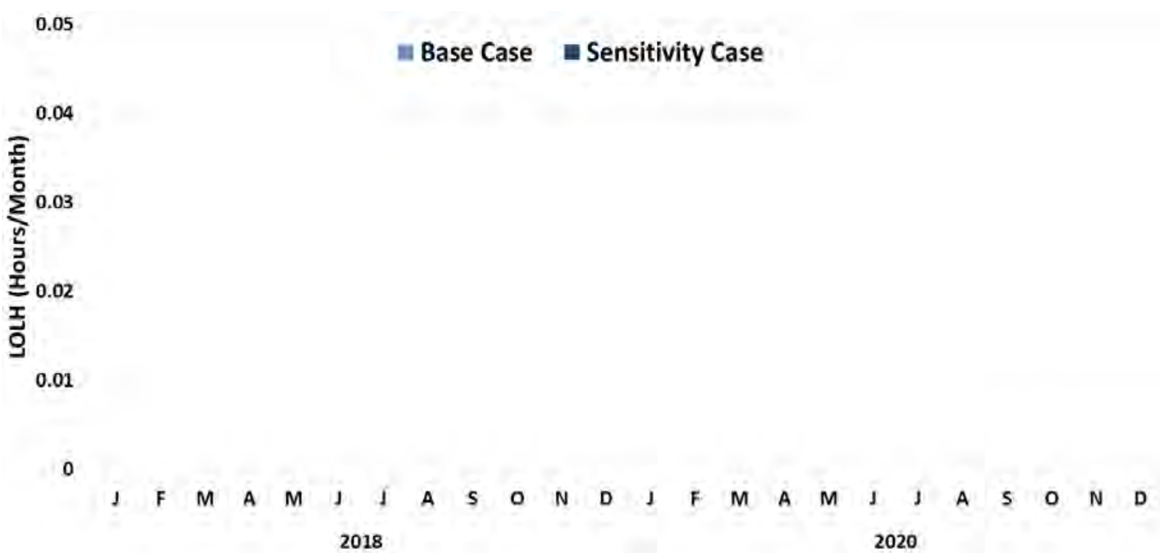
Base Case Study

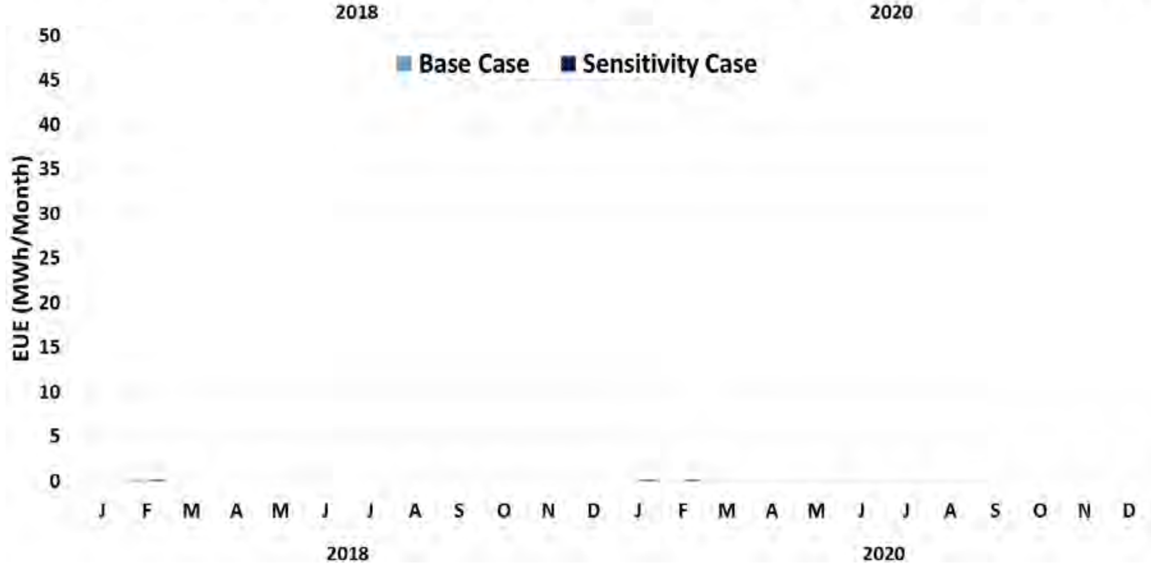
No significant LOLH is observed. EUE is 0.005 in 2018 and negligible in 2020. Anticipated Reserve Margins are well above 20 percent in both years. The greatest contribution to the LOLH and EUE occur during the peak (winter) monthly period.

Sensitivity Case Study

LOLH is also not significant in this case, the EUE values are negligible: 0.03 and 0.004 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above 20 percent in 2018 and near 20 percent in 2020.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	26.42	24.37	23.8	19.4
Prospective	26.79	25.77	-	-
Reference	20.0	20.0	-	-
ProbA Forecast Planning	26.4	24.4	23.8	19.4
ProbA Forecast Operable	20.0	18.1	17.5	13.3
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.005	0.000	0.030	0.004
EUE (ppm)	0.000	0.000	0.001	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





Overview

The Maritimes Area is comprised of four subareas: New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM), where a 20 percent reserve margin target is used. This reserve level correlates closely to the amount of reserve necessary to meet the 0.1 days per year LOLE criterion required by the Northeast Power Coordinating Council (NPCC). The close correlation is confirmed annually during NPCC resource adequacy reviews.

Resources in the Maritimes Area are subject to capacity deratings that account for variances in seasons in the case of variable generation and the likelihood of the resource being available if called upon. If derated resources result in inadequate margins looking forward in time, then new resources must be acquired.

The aggregated load growth for the four combined subareas of the Maritimes Area is practically flat for both the summer and winter seasonal peak load periods. They have an average growth rates of 0.2 percent per year in summer and a decline of 0.13 percent per year in winter.

Load growth for the southeastern corner of the NB subarea (including the much smaller PEI subarea) is not specifically identified in the load projections, but NB has historically outpaced growth in the rest the Maritimes Area. NB Power has added under-voltage load shedding equipment at two new sites and applied temperature compensation to restricting lines to increase transfer capabilities. In addition, demand side management (DSM) programs aimed at reducing and shifting peak demands and potential imports to NB from NS could reduce transmission loading in the southeastern NB area. These imports may begin after the completion of the high-voltage direct current (HVdc) interconnection to the Canadian province of Newfoundland and Labrador. No other reinforcements are planned at this time.

During the 10-year LTRA assessment period in the Maritimes Area, annual amounts for summer peak demand reductions associated with energy efficiency programs rose from 7 MW to 92 MW, and the annual amounts for winter peak demand reductions rose from 43 MW to 555 MW. Most of this amount is related to intensive demand shifting programs in New Brunswick that will focus mainly on reducing and/or shifting water and space heater demands during peak load periods. This is done by using smart metering technology to control their consumption patterns. Interruptible loads are the only specifically forecasted DR programs in the Maritimes Area. During the assessment period, no significant changes from previously reported amounts for interruptible loads are expected to occur.

Nova Scotia is projecting three installed capacity additions by January 2020: 49 MW of wind, 3.6 MW of solar, and 23 MW of biomass/biogas. In addition, transmission restrictions on a 45 MW formerly energy-only biomass generator in Nova Scotia are being removed before January 2018, and the generator's capacity will then be counted as firm capacity. Also, an unconfirmed retirement of a 153 MW coal-fired unit in Nova Scotia is expected in mid-2020. This capacity will be offset by an expected firm purchase of hydro capacity over the new HVdc link with the Canadian province of Newfoundland and Labrador. The retirement of the coal unit will be correspondingly delayed should a delay occur in the introduction of energy from the new hydro capacity.

Renewable energy standards (RESs) have led to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and may, with increasing levels in the future, require displacement of wind generation with conventional generation during light load periods. With the significant amount of large scale wind energy currently being balanced on the NB system, the next phase of renewable energy development in NB will focus on smaller scale projects with a particular emphasis on nonintermittent forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will provide renewable hydro resources that may otherwise have been provided by intermittent resources and would have further reduced frequency response capability.

With respect to capacity deratings for renewable variable generation, NB derates wind capacity using a calculated year-round equivalent capacity of 20 percent for the Maritimes Area. NS and PEI derate wind capacity to 12 percent and 15 percent of nameplate based on calculated year-round equivalent capacities for their respective sub areas. NM derates wind to 26 percent and 46 percent of nameplate based on summer and winter seasonal capacity factors, respectively.

There are no trends developing for either imports or exports; however, a long-term import contract starting in mid-2020 is expected to offset the unconfirmed retirement of a coal unit in Nova Scotia. This offset is expected to be with replacement hydro capacity over the HVdc cable link (currently under construction to Newfoundland and Labrador. The capacity of the import and the unit retirement are comparable and are planned to coincide in timing, thus overall resource adequacy is unaffected by these changes.

Transmission development in the Maritimes Area during the assessment period includes installation of a 345 kV breaker in series with an existing breaker at NB's Point Lepreau terminal in the spring of 2016. This will mitigate contingencies and reduce import restrictions from New England. During the winter of 2016/17, the installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of 9 miles, will be completed. This will increase capacity and improve the ability to withstand transmission contingencies in the area between NB and PEI. A 475 MW HVdc undersea cable link (Maritime Link) between Newfoundland and Labrador and NS will be installed by early 2018. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing unit at the Keswick terminal in NB to mitigate the effects of transformer contingencies at the terminal. No delays are expected for these projects.

No modifications have been made to the assessment area's planning assumptions or methods in response to extreme weather events. The hydro-electric power supply system in the Maritimes Area, with a capacity of approximately 1330 MW, is predominantly run-of-the-river as opposed to storage based. Large quantities of energy cannot be held in reserve to stave off drought conditions. If such conditions occur, the hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems available only for load following and/or peak supply. The Maritimes Area is not overly reliant on wind capacity to meet resource adequacy requirements. The lack of wind during peaks (or very high wind speeds and/or icing conditions that would cause wind farms to suddenly shut down) should not affect the dependability of supply to the area. This is because ample spinning reserve is available to cover the loss of the largest base loaded generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the area.

The Maritimes Area has a diversified mix of capacity resources fueled by nuclear, oil, coal, natural gas, dual fuel oil/natural gas, hydro, wind (derated), and biomass with no one type feeding more than about 26 percent of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. The Maritimes Area does not anticipate fuel disruptions that pose significant challenges to resource adequacy in the area during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions.

The Maritimes Area has begun tracking the ramp rate variability trend, but does not yet have enough historical years of data for the area as a whole to identify any trends. Given the essentially flat load growth and small degree of anticipated VER installations, little change in either ramp rates or the area's resource mix is expected to occur for the duration of the LTRA assessment period. The maximum net demand ramping variability (1 hour up, 1 hour down, 3 hours up, and 3 hours down values) for two historical years of 2014 and 2015 and a future year of 2020 were calculated along with the percentage contributions of VERs versus the loads. The majority of the maximums occurred during the late fall shoulder and winter peak seasons. The Maritimes Area is a winter peaking area. Five minute interval samples were used for these calculations. The values for 2020 were scaled up from the actuals used for 2015.

The following table outlines the results of the Maritimes area review. NDRV stands for net demand ramping variability, and VER stands for variable energy resource.

Year	Variable	NDRV (MW)	Date	VER (MW)	Load (MW)	VER/load (%)
2014	1 hour UP	637	Dec. 8, 2014	281	4,295	6.5
2014	1 hour DOWN	-617	Nov. 17, 2014	576	3,372	17.1
2014	3 hours UP	1262	Dec. 5, 2014	415	3,622	11.5
2014	3 hours DOWN	-1072	Nov. 17, 2014	546	3,683	14.8
2015	1 hour UP	606	Feb. 2, 2015	354	4,653	7.6
2015	1 hour DOWN	-416	Dec. 17,2015	485	3,546	13.7
2015	3 hours UP	1172	Oct. 28, 2015	417	2,702	15.4
2015	3 hours DOWN	-953	Dec. 17,2015	403	3,785	10.6
2020	1 hour UP	629	Feb. 2, 2020	373	4,828	7.7
2020	1 hour DOWN	-434	Dec. 17,2020	511	3,679	13.9
2020	3 hours UP	1219	Oct. 28, 2020	439	2,804	15.7
2020	3 hours DOWN	-993	Dec. 17,2020	425	3,927	10.8

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system; ISO-NE also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

Summary of Methods and Assumptions

Reference Margin Level
The installed capacity requirement (ICR) results in a Reference Margin Level of 16.74 percent in 2017, declining to 16.55 percent in 2018 and expected to be 15.93 percent for the remainder of the assessment period.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

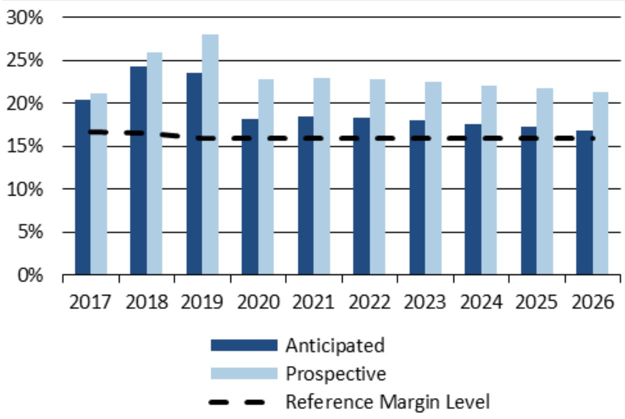
Planning Considerations for Wind Resources
A value of 5 percent of the total nameplate for on-shore and 20 percent of nameplate for off-shore resources

Planning Considerations for Solar Resources
A value of 38 percent of nameplate in 2017, decreasing annually to 34 percent in 2026

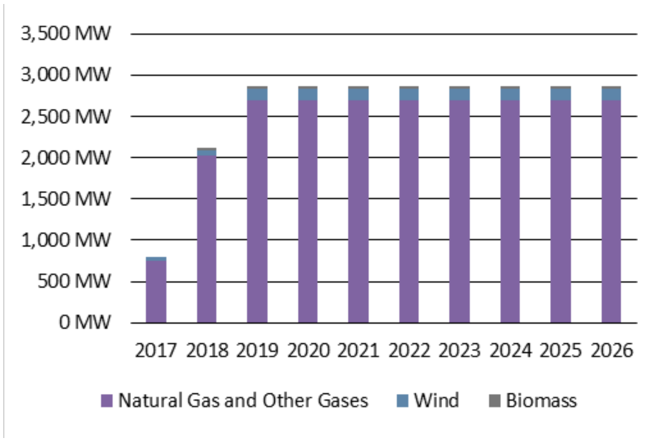
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	26,698	26,765	26,783	26,789	26,816	26,870	26,942	27,026	27,122	27,218
Demand Response	841	597	378	378	378	378	378	378	378	378
Net Internal Demand	25,857	26,168	26,405	26,411	26,438	26,492	26,564	26,648	26,744	26,841
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31,112	32,529	32,617	31,226	31,330	31,336	31,342	31,347	31,353	31,353
Prospective	31,313	32,935	33,803	32,412	32,516	32,522	32,528	32,533	32,539	32,539
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.32%	24.31%	23.52%	18.23%	18.50%	18.28%	17.99%	17.63%	17.23%	16.81%
Prospective	21.10%	25.86%	28.02%	22.72%	22.99%	22.76%	22.45%	22.08%	21.67%	21.23%
Reference Margin Level	16.74%	16.55%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- The New England Area is a summer peaking area comprised of New Hampshire, Rhode Island, and Vermont. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures. This is as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[87]

- **Results trending:** The previous study (*NERC RAS Long-Term Reliability Assessment—NPCC Region*)[88] estimated an annual LOLH equal to 0.288 hours per year and a corresponding EUE equal to 253.8 MWh for the year 2018. The Forecast 50/50 peak demand for 2018 was lower than reported in the previous study with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2018.

- **Probabilistic vs. Deterministic Reserve Margin Results:** New England's reference reserve margin is determined based on the NPCC resource adequacy criterion; this results in a reference reserve margin level of 16.6 percent in 2018, and 15.9 percent for 2020.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview*, and are consistent with those described in the *2016 NERC RAS Probabilistic Assessment—NPCC Region.*[89]

[87] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[88] NPCC RAS Probabilistic Assessment; March 2015
[89] NPCC Library - Resource Adequacy

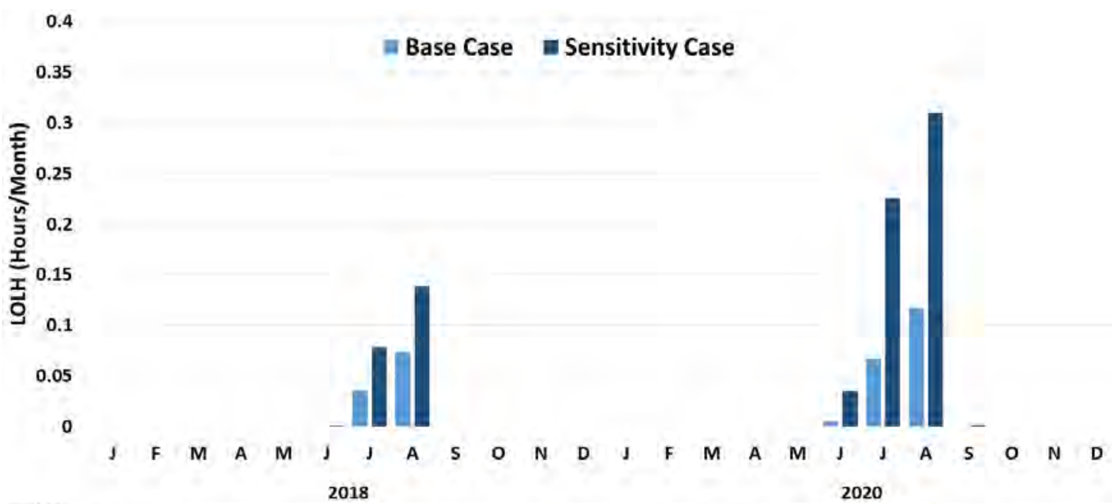
Base Case Study

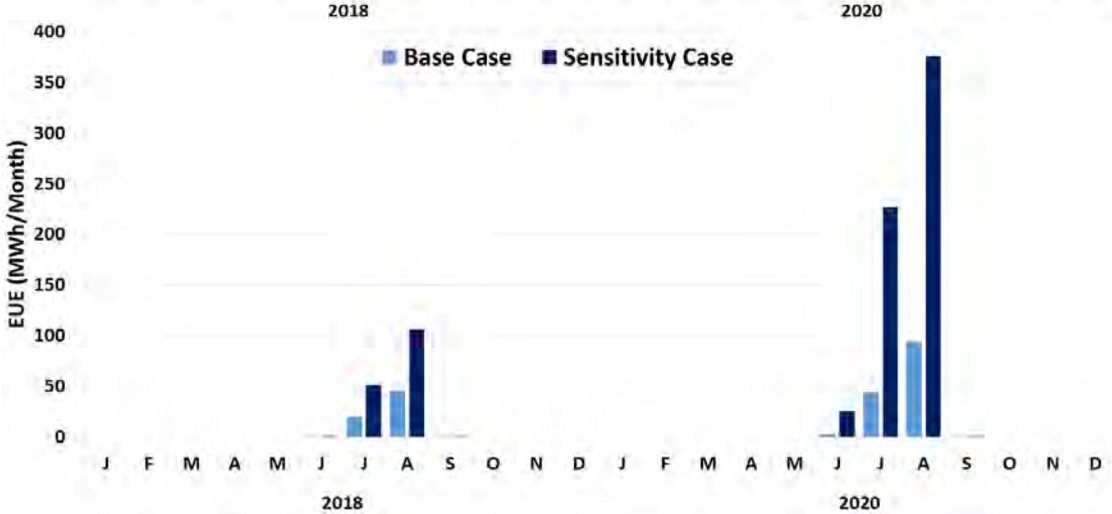
In 2018, LOLH is 0.109 h/year and EUE is 65.2 MWh while in 2020 those values are 0.189 h/year and 140.8 MWh, respectively. The increases are consistent with a decline in reserve margins. The metrics are primarily driven by the results in July and August.

Sensitivity Case Study

LOLH and EUE increase exponentially with the decline in reserve margins. LOLH is 0.218 and 0.573 h/year for 2018 and 2020, respectively. EUE is 157.7 and 528.6 MWh for those two years. As it was the case in the Base Case, July and August have the biggest share of the annual metrics.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	24.31	18.23	21.5	13.4
Prospective	25.86	22.72	-	-
Reference	16.6	15.9	-	-
ProbA Forecast Planning	24.0	18.0	21.5	13.4
ProbA Forecast Operable	15.4	9.4	13.1	5.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	65.2	140.8	157.7	628.6
EUE (ppm)	0.460	0.977	1.090	4.191
LOLH (hours/year)	0.109	0.189	0.218	0.573





Overview

ISO New England's (ISO-NE) Reference Margin Level is based on the capacity needed to meet the Northeast Power Coordinating Council (NPCC) 1-in-10-year LOLE resource planning reliability criterion. The amount of capacity needed, referred to as the installed capacity requirement (ICR), varies from year-to-year, depending on expected system conditions. The capacity needed to meet the LOLE criterion is purchased through annual forward capacity auctions three years in advance. Reconfiguration auctions occur annually prior to the commencement year to assure an opportunity to adjust capacity purchases to meet changing requirements.

ISO-NE's Anticipated Reserve Margin, which ranges from a high of 24.3 percent in 2018 to a low of 16.8 percent in 2026, remains above the Reference Margin Level through the assessment period.

The summer peak total internal demand (TID), which takes into account energy efficiency and conservation as well as behind-the-meter photovoltaic (PV) resources, is forecasted to increase from 26,698 MW in 2017 to 27,218 MW in 2026. This amounts to a nine-year summer TID compound annual growth rate (CAGR) of 0.21 percent, as compared to the *2015 LTRA* projection of 0.48 percent. The primary reasons for the decrease in the demand forecast are updated historical data, and an increased amount of behind-the-meter PV. As behind-the-meter PV resources increase, New England could experience daily load profiles that would require different resource operating attributes to manage reserve, ramping, and regulation requirements.

Both passive and active DR are procured through ISO-NE's forward capacity market (FCM). Passive DR, which consists of energy efficiency and conservation, will grow to 2,561 MW by 2019 in the FCM. For the years beyond the FCM commitment periods, ISO-NE uses an energy efficiency forecasting methodology that takes into account the potential impact of growing energy efficiency and conservation initiatives throughout the region. Energy efficiency has generally been increasing over time and is projected to continue growing throughout the study period. The amount of energy efficiency is projected to increase to over 4,000 MW by 2026. Active demand resources consist of DR and emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4: *Action during a Capacity Deficiency* (OP-4).[90] The capacity supply obligations (CSOs) for these resources, which are obtained through ISO-NE's FCM, decrease from 556 MW in 2016 to 378 MW in 2019.

A total of 319 MW of new capacity consisting primarily of PV and wind resources have been added since the *2015 LTRA*. Approximately 2,900 MW of Tier 1 capacity, including over 2,700 MW of natural-gas-fired plants, will be added by 2019. The largest natural gas projects are the Footprint Combined Cycle Plant (674 MW), which is projected to be in service in 2017, and the CPV Towantic Energy Center (725 MW) as well as PSEG's Bridgeport Harbor Expansion (484 MW), both of which are to be in service in 2018. Also included in the Tier 1 category is 133 MW of on-peak wind capacity (806 MW nameplate). Tier 2 capacity additions totaling 1,012 MW include 982 MW of natural-gas-fired generation and 125 MW of nameplate wind.

The amount of renewable resources in New England continues to grow. In addition to behind-the-meter PV that reduces the load forecast, there has been growth in PV participating in ISO-NE markets, with on-peak capacity increasing from 264 MW in 2017 to 329 MW in 2025. Although the amount of Existing and Tier 1 wind capacity only amounts to 229 MW on peak, there is an additional 3,400 MW of nameplate wind capacity in the ISO-NE generator interconnection queue.

Over 2,100 MW of retirements are expected in New England by 2019. Brayton Point Station, which is a 1,535 MW coal and oil plant, will be retiring by June 2017. The 680 MW Pilgrim Nuclear Power Station is planned for retirement by June 2019. Even with these retirements, ISO-NE's reserve margin is not expected to fall below the 15.9 percent Reference Margin Level during the assessment period. If capacity is required to meet the regional resource

[90] OP-4 is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus operating reserve requirement.

adequacy, ISO-NE will purchase the needed capacity through its forward capacity market (FCM). Currently, over 680 MW of Tier 2 capacity has a capacity supply obligation in the FCM.

The major transmission project currently under development in New England is the Greater Boston project. The Greater Boston upgrades are critical to improve the ability to move power into the Greater Boston area and from northern New England to southern New England. This set of upgrades includes new and upgraded 345 kV and 115 kV lines, new autotransformers, and additional reactive support. The project is certified to be in service by June 2019.

For over a decade, the region has been working on gas-related challenges and will continue to do so. New England's generation fleet is changing rapidly with the retirement of older fossil-fueled resources and their replacement by new gas-fired generators. The region's reliance on natural gas for power generation has been increasing and will likely continue to do so in the future. ISO is addressing the gas-related challenges with market rule changes and operational enhancements. Recent market rules, such as those addressing energy market offer flexibility, allow resources to more accurately reflect their variable costs in their energy offers during the operating day, which improves incentives to perform. Another new market rule has changed the timing of the day-ahead energy market to align more closely with natural gas trading deadlines. In addition, the ISO has improved coordination and information-sharing with natural gas pipeline operators, such as working with the pipelines to coordinate generator and pipeline maintenance schedules. The ISO has also developed a natural gas usage tool that estimates the remaining gas pipeline capacity, by individual pipe, for use by ISO-NE system operators to determine whether the electric sector gas demand can be accommodated.

A winter fuel-reliability program has been acting as a bridge between now and 2018 when the longer-term pay-for-performance (PFP) capacity market changes go into effect. The winter reliability program addresses regional winter reliability challenges created by New England's increased reliance on natural-gas-fired generation and lack of adequate gas infrastructure. Resources participating in the program provide incremental energy inventory during the winter months to help ensure reliable system conditions. Components of the program include payment to generators for adding dual-fuel capability, securing fuel inventory, testing fuel-switching capability, compensation for any unused fuel inventory, and nonperformance charges.

PFP, which starts in June 2018, will help improve reliability while ensuring resource adequacy. PFP is a two-part settlement in which a base payment is set in the forward capacity auction and a performance payment is determined during the delivery year. The performance payment may be positive or negative, depending on resource performance during a shortage condition. Over-performing resources are paid a premium through revenue transfers from under-performing resources. PFP creates an incentive for investment in generators that are either: 1) low-cost and highly reliable (nearly always operating), or 2) highly flexible and highly reliable (goes on-line quickly and reliably). PFP will encourage generators to increase unit availability by implementing dual-fuel capability, entering into firm gas-supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site oil, LNG fuel storage, or expanded gas pipeline infrastructure.

In summary, New England has adequate capacity resources to meet the NERC Reference Margin Level throughout the *2016 LTRA* study period. ISO New England has been faced with gas-related challenges for more than a decade. These challenges will remain as additional non-gas-fired resources retire and are replaced by gas-fired generation. ISO New England expects and continues to make operational and market enhancements to address these challenges. ISO New England is cognizant of possible operational issues that a high penetration of intermittent resources may pose in the future. The region has conducted and will continue to conduct studies to identify means to address these future operational issues. Furthermore, New England has a robust transmission planning process. Existing and planned transmission upgrades will ensure regional system reliability.

NPCC-New York

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid, which encompasses approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

Summary of Methods and Assumptions

Reference Margin Level

The New York State Reliability Council (NYSRC) installed reserve margin (IRM) of 17.5 percent applies to the period May 2016 to April 2017. New York's IRM is set annually.

Load Forecast Method

The New York Balancing Authority (NYBA) forecast is based upon an econometric forecast of annual energy and seasonal peak demands. The New York State Reliability Council (NYSRC) has adjustments for energy efficiency and DERs, including behind-the-meter solar PV.

Peak Season

The seasonal peak demands (summer and winter) are based upon annual energy and seasonal load factors. The forecast load factors are based upon recent historic data and then trended for the future.

Planning Considerations for Wind Resources

The expected on-peak capacity for wind resources is 14 percent.

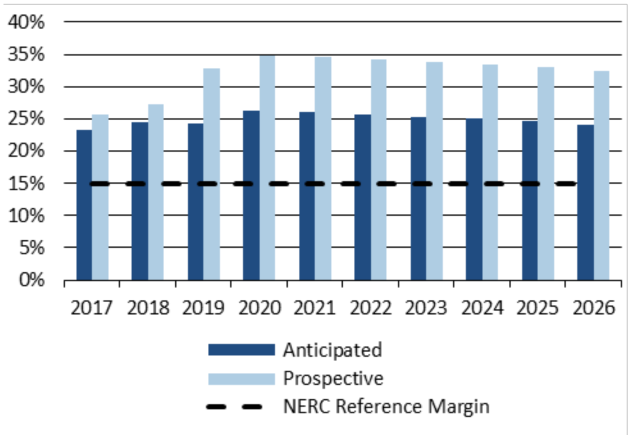
Planning Considerations for Solar Resources

On peak resources for solar PV include a number of factors, such as inverter sizing and efficiency, the impact of cloud cover and other atmospheric conditions that attenuate solar irradiance, and the seasonal and diurnal variations in solar irradiance.

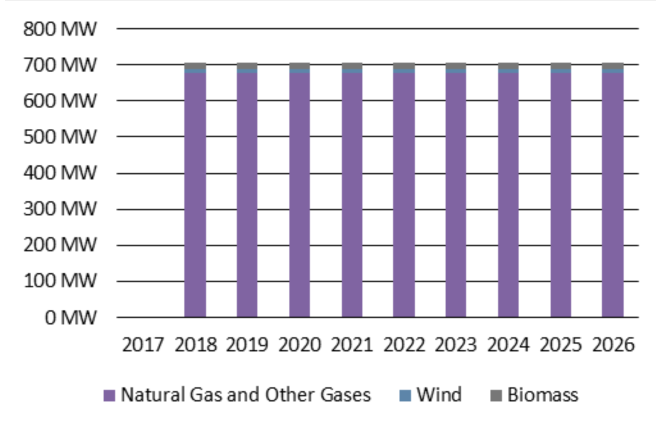
Footprint Changes – N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	33,363	33,404	33,477	33,501	33,555	33,650	33,748	33,833	33,926	34,056
Demand Response	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248
Net Internal Demand	32,115	32,156	32,229	32,253	32,307	32,402	32,500	32,585	32,678	32,808
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	39,613	40,056	40,065	40,727	40,727	40,727	40,727	40,727	40,727	40,727
Prospective	40,382	40,923	42,805	43,474	43,474	43,474	43,474	43,474	43,474	43,474
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	23.35%	24.57%	24.31%	26.27%	26.06%	25.69%	25.31%	24.99%	24.63%	24.14%
Prospective	25.74%	27.26%	32.81%	34.79%	34.56%	34.17%	33.76%	33.42%	33.04%	32.51%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The New York Area is a summer peaking area. The GE MARS model developed by the NPCC CP-8 Work Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.[91]

- **Results Trending:** The previous study, the *NERC RAS Long-Term Reliability Assessment – NPCC Region*[92] estimated an annual LOLH = 0.032 hours per year and a corresponding EUE equal to 9.3 MWh for the year 2018. The Forecast 50/50 Peak Demand for 2018 was lower than reported in the previous study, but with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2018.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The New York IRM of 17.5 percent applies to the period May 2016 to April 2017.[93] New York's IRM is set annually. New York does not have a future reference reserve margin beyond the current capability period thus the NERC reference reserve margin is used.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in the *NPCC 2016 Long Range Adequacy Overview,* and it is described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[94] All New York published reports and probabilistic studies report reserve margins based on the full ICAP value of all resources.

[91] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[92] NPCC NERC RAS Probabilistic Assessment; March 2015
[93] New York State Reliability Council: New York Control Area Installed Capacity Requirements Reports
[94] NPCC Library - Resource Adequacy

Base Case Study

LOLH for 2018 and 2020 are 0.004 (hours per year) with EUE values of 1.448 and 2.059 (MWh). The EUEs are negligible. Results are similarly driven by a comparable planning reserve margin in both years. The summer months (June–August) have the greatest contribution to these metrics.

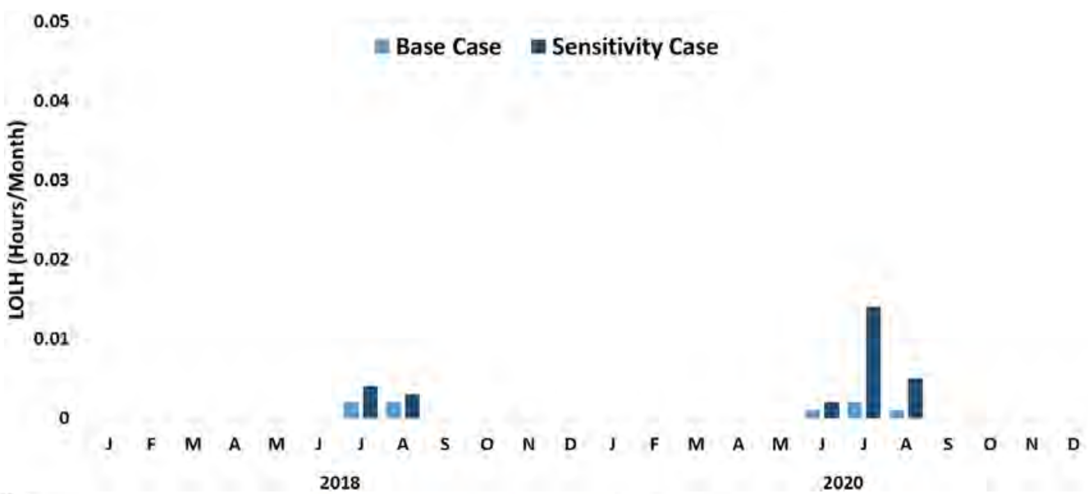
Sensitivity Case Study

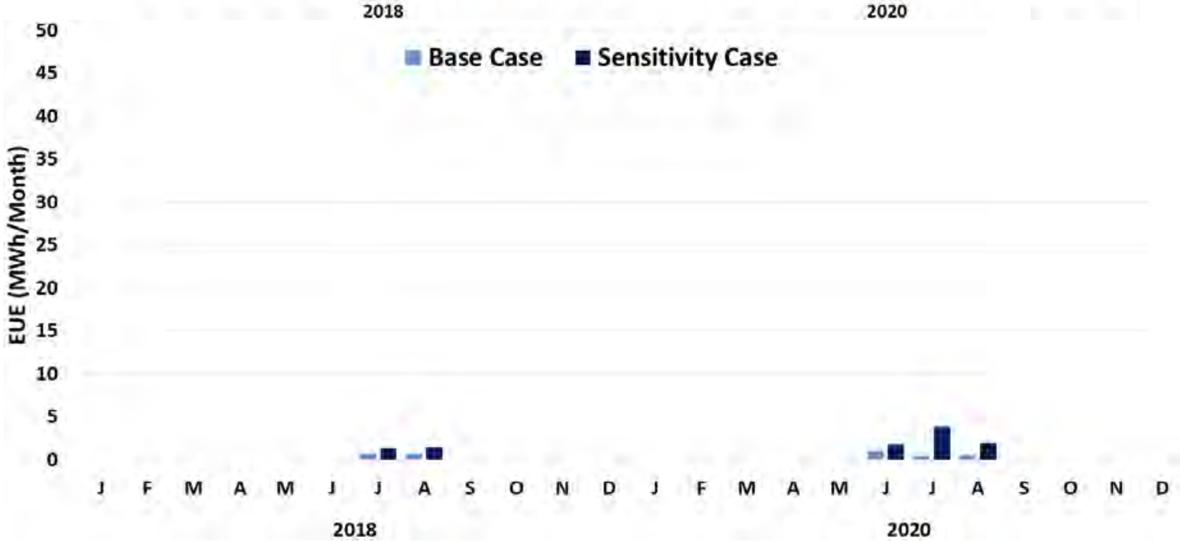
LOLH values are 0.007 and 0.021 for 2018 and 2020, respectively. EUE results are 2.8 and 7.6 MWh for those same two years. The monthly contribution is similar to that observed in the Base Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated *	24.57	26.27	23.6	20.8
Prospective *	27.26	34.79	-	-
NERC Reference	15	15		
ProbA Forecast Planning **	28.6	30.3	26.0	25.1
ProbA Forecast Operable **	17.1	18.8	14.7	14.0
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	1.448	2.059	2.777	7.557
EUE (ppm)	0.009	0.013	0.017	0.046
LOLH (hours/year)	0.004	0.004	0.007	0.021

* NERC LTRA reserve margin calculations are based on a 14 percent wind unit peak capacity factor.

** Wind units modeled in the probabilistic assessment as hourly load modifiers are based on 2013 production data, and ProbA capacity resource interconnection service values are used for reserve margin calculations.





Planning Reserve Margins

The annual IRM for the New York Balancing Area (NYBA) is calculated through a technical study conducted by the New York State Reliability Council (NYSRC) in accordance with NERC Reliability Standards, the Northeast Power Coordinating Council (NPCC) reliability criteria, and the NYSRC Reliability Rules. For the 2016–2017 capability year, the NYSRC approved an IRM requirement of 17.5 percent. New York does not have a future reference reserve margin beyond the current capability period, ending April 2017.

The New York IRM assumed that the ~1,455 MW of wind capacity will likely operate at a 14 percent capacity factor during the summer peak period. This assumed capacity factor is based on an analysis of actual hourly wind generation data collected for wind facilities in New York State during the June through August 2013 period between 2:00 and 5:00 p.m. This test period was chosen because it covers the time during which virtually all of the annual NYCA LOLE occurrences are. For the calculation of New York IRM, wind generators are modeled as hourly load modifiers. In the probabilistic determination of the New York IRM, the output of each unit varies between 0 MW and the capacity resource interconnection service value based on 2013 production data.

All generator values for the IRM requirement calculation are based on generator installed capability values as reported in the 2016 NERC LTRA and the current *Load and Capacity Data Report* issued by the New York Independent System Operator, Inc. (NYISO). For reporting purposes, the capacity values provided for New York existing and planned resource facilities are consistent on its dependable maximum net capability (DMNC). In circumstances where the ability to deliver power to the grid is restricted, the value of the resource is limited to its capacity resource interconnection service (CRIS) value. The source of DMNC ratings for existing facilities are seasonal tests required by procedures in the *NYISO Installed Capacity Manual* and are documented in the *New York Gold Book*.[95]

Demand

The baseline energy forecast for the years 2016–2026 is expected to decline at an average rate of -0.16 percent per year, while the baseline summer peak demand forecast for the years 2016–2026 is expected to grow at annual average rate of 0.21 percent. The lower forecasted growth in energy usage for years 2016–2026 is largely attributable to an increase in the impacts of energy efficiency initiatives and the growth of distributed behind-the-meter energy resources.

Demand-Side Management

There were no significant changes to NYISO's DR programs since last year's *LTRA*. The 2016 forecast includes peak demand impacts of 1) energy efficiency initiatives in the amount of 1,859 MW, 2) solar PV in the amount of 747 MW, and 3) distributed generation in the amount of 356 MW. These are cumulative impacts expected by the year 2026.

DR enrollments are currently trending at approximately 4.3 percent of the NYBA's peak load, and there is no indication that there will be a significant increase in enrollment in the near future. The NYISO does not anticipate significant long-term reliability impacts from a modest increase in the DR enrollments from the current enrollment levels.

Generation

Since the *2015 LTRA*, there were no new resource additions installed in the NYBA. Tier 1 resource additions total 775 MW and are expected to be in service for Summer 2018. Tier 2 resources total 4,140 MW and are at various stages in the NYISO interconnection process. However, the NYBA had 637.8 MW of summer capacity deactivate, and they have another 1,734.8 MW of capacity scheduled to deactivate over the assessment period. The NYISO

[95] NYISO: 2016 Load & Capacity Data

did not identify any near-term reliability needs resulting from these deactivations. Other than these deactivations, no large generators are expected to be unavailable over the assessment period.

In response to an April 2016 order from the Federal Energy Regulatory Commission (FERC), NYISO is further developing a tariff process to be filed in September 2016 to address reliability needs that arise from generator deactivations and the planning process for identifying solutions; this includes the potential need for a reliability-must-run agreement to keep the deactivating generator in service until permanent solutions can be provided.

The forecast for distributed behind-the-meter generation for the summer peak demand is 313 MW in 2021 and 356 MW in 2026. DERs are expected to increase in the future with behind-the-meter solar growing at the fastest rate. Projected additions are based upon current rates of growth in each NYBA zone, together with an expectation of how future state incentives for distributed generation will affect installation of these resources.

Changing Resource Mix

New York State had a renewable portfolio standard (RPS) that has been supplanted by other state programs, including a large-scale renewables program under the New York State Clean Energy Fund (CEF). The RPS program purchased renewable energy credits from seventy active projects that represented 2,152 MW. These programs produced more than 5,000 GWH in 2015 and more than 90 percent of this renewable generation was produced by wind resources. Currently, the New York State Energy Plan calls for 50 percent of energy generation to come from renewable energy sources by 2030. The New York State Public Service Commission (NYSPSC) is currently developing a clean energy standard that is intended to achieve the goals of the New York State Energy Plan and to preserve the financial viability of the existing nuclear generators in New York. The New York State Department of Public Service staff estimates that the proposal calls for 75,000 GWH of annual renewable energy production by 2030. The NYSPSC has not yet finalized the specific types of renewable generation that will be included under the CES.

One of New York State's initiatives, the NY-Sun Incentive Program (NY-Sun), is designed to have 3,000 MW of installed solar PV capacity on the system by the end of 2023. In April 2014, following two successful years of solar PV installations, a commitment of nearly $1 billion was made to NY-Sun for further installation of solar PV.

In response to the increasing amount of VERs and New York State's initiatives, the NYISO studied a number of specific grid operation needs potentially affected by the increasing penetration of intermittent solar PV and wind resources. The study found, among other things, that 1) the bulk power system can reliably manage over the five-minute time horizon the increase in net load variability associated with the solar PV and wind penetration levels up to 4,500 MW wind and 9,000 MW solar PV, 2) the large-scale implementation of behind-the-meter solar PV will impact the NYISO's load profile and associated system operations, and 3) the lack of frequency and voltage ride-through requirements for solar PV facilities in New York could worsen system contingencies when solar PV deactivates in response to frequency and voltage excursions. Likewise, wind resources in New York are increasing and now total approximately four percent of the generation fleet by fuel source. A 2010 NYISO wind generation study[96] examined the impact of adding up to 8,000 MW of wind resources and it indicated that, above 3,500 MW of wind penetration, regulation requirements are projected to increase at the rate of 25 MW for every 1,000 MW increase in wind generation.

NYISO has not changed the methods that it uses to determine the on-peak capacity values for wind, solar, and hydro. Hourly unit output data for wind, run of river hydro, and solar units are collected for the summer peak hours (i.e., 2:00 p.m.–5:00 p.m.) from June 1 through August 31. The on-peak capacity for these resources is determined using an assumed capability for each resource class; this is based upon unit historic operating data and engineering judgment. For reserve margin calculations, NYISO uses the full on-peak capability of the units,

[96] NYISO: Growing Wind: Final Report of the NYISO 2010 Wind Generation Study; September 2010

which represents the aggregate capacity for each resource class (i.e., wind, solar, and hydro). The expected on-peak capacity factors for wind, solar, and hydro are 14 percent, 56.5 percent, and 54 percent respectively.

Capacity Transfers

NYISO has three classifications of capacity transfers:

- The first includes grandfathered contracts and external capacity resource interconnection service (CRIS) rights. These total 2170 MW and cover the entire *2016 LTRA* assessment period.
- The second class is unforced deliverability rights (UDRs). These are rights to deliver capacity over controllable tie lines. For the NYBA, the total UDR capability is 1,965 MW across the four controllable tie lines. The owners of the UDRs notify NYISO each year of the amount of capacity that will be delivered. UDR election levels are treated by NYISO as confidential information. Any transfer capability not utilized is available to provide emergency assistance in both the NYISO's planning studies and operationally, if the need arises.
- The third classification of capacity transfers is import rights. For 2016, import rights totaled 530 MW and are available month to month on a first-come, first-served basis in the capacity auctions.

Capacity transactions modeled in the NYISO's assessments have met the capacity resource requirements, as defined in the NYISO's tariffs. Both NYISO and its respective neighboring assessment areas have agreed upon the terms of the capacity transaction including the MW value, the duration, the contract path, the source of capacity, and the capacity rating of the resource.

Transmission and System Enhancements

The NYBA has three major transmission projects located in central New York, downstate New York, and New York City, all placed into service in June 2016. These include Marcy-South Series Compensation and Fraser-Coopers Corners 345 kV line reconductoring, construction of a second Rock Tavern-Ramapo 345 kV line, and Phase I (i.e., cable separation) of upgrading underground transmission circuits from Staten Island to the rest of New York City (collectively, "Transmission Owner Transmission Solutions" or "TOTS"). Approved by the NYSPSC as part of New York's Energy Highway initiative, the TOTS projects are expected to increase transfer capability into southeastern New York by 450 MW and mitigate against potential reliability needs if the Indian Point Energy Center were to become unavailable.

In the 2014 *Reliability Needs Assessment* (*RNA*), NYISO identified thermal violations under N-1-1 post-contingency conditions (applying more stringent NPCC criteria) that would limit transmission in the Rochester and Syracuse areas. For the Rochester area, the overloads are on 345/115kV transformers that supply the Rochester area upon loss of other 345/115kV transformers in the same area; the Syracuse area overloads on 115kV facilities upon loss of parallel lines. These violations are anticipated to be resolved with permanent solutions identified in the most recent Transmission Owner local transmission plans, scheduled to be completed by Summer 2017 in the Rochester area and the end of 2017 in the Syracuse area. In the interim, the local transmission owners will implement local operating procedures, if required, to prevent overloads, including the potential for limited load shedding in the Rochester and Syracuse areas; voltage-constrained transfer limits are evaluated and determined by NYISO for all major interfaces within New York. BPS transmission security is maintained by limiting power transfers according to the determined voltage-constrained transfer limits. Local nonbulk voltage performance is evaluated by the local Transmission Owner and addressed through the Local transmission planning process.

Transmission security of the NYBA BPS is maintained by limiting power transfers according to the determined transfer limits, including voltage-constrained transfer limits. New York has three interfaces that were found to be voltage limited, and NYISO maintains voltage limits in these constrained areas by limiting power transfers to mitigate dynamic and static reactive power issues. Based on the foregoing, NYISO does not expect to use under-voltage load shedding schemes.

Depending on assumed system conditions, the Central East interface is limited at certain times due to dynamic instability. As part of the annual NYISO Area Transmission Review (ATR), the flows on the evaluated interfaces were tested at a value of at least 10 percent above the more restrictive of the emergency thermal or voltage transfer limits in accordance with NYISO Transmission Planning Guideline #3-0.[97] The 2014 intermediate ATR performed dynamic stability simulations for NERC contingencies that were expected to produce the more severe system results or impacts based on examination of actual system events and assessment of changes to the planned system. BPS transmission security is maintained by limiting power transfers according to the determined stability limits.

The New York Balancing Authority will also have additions and removals of special protection systems (SPSs) since the last LTRA. Generation rejection SPSs are being retired at the Niagara hydro facility and the St. Lawrence Moses hydro facility, which will become effective upon completion of the NPCC approval process. Both facilities have added power system stabilizers to their units and a study showed that thermal limits, voltage, and stability would be maintained for the contingencies at those facilities. Additionally, an SPS is being added to mitigate subsynchronous resonance issues when the new series compensated lines in the TOTS projects are placed in service in Summer 2016. The SPS will detect certain outage conditions and signal to bypass the series compensation.

Long-Term Reliability Issues

NYISO continues to plan for extreme weather and has not made any modifications to its planning assumptions or methods for such events. NYISO continues to conduct its reliability studies using the 50/50 load forecast as the base assumption and account for weather events with a load forecast uncertainty (LFU). Additionally, NYISO, in conjunction with its stakeholders, is exploring market rule changes to help assure fuel availability during cold weather conditions. Improvements will be considered in reporting seasonal fuel inventories and daily replenishment schedules. NYISO will work with New York State regulatory agencies to develop a formal process to identify reliability needs that would be mitigated by generator requests for certain waivers.

NYISO only conducts dynamic stability studies for the off-peak periods and, in doing so, identified no concerns. Generators in the fleet use the off-peak period to schedule and perform their routine maintenance in preparation for the summer and winter peak seasons. NYISO monitors and approves maintenance schedules to maintain system reliability and can cancel scheduled maintenance if system conditions warrant it.

As a part of NYISO's *2014 Comprehensive Reliability Plan*[98] and the *2015 Power Trends report*[99], NYISO identified several risk factors to maintaining reliability in New York. These factors include the following:

- **Changes to System Performance:** The aging generation infrastructure may lead to more frequent and longer outages as well as increasing costs, which may drive more retirements. Since 2000, more than 11,000 MW of generation has been added while more than 6,000 MW are no longer active. Of the current generation fleet, 8.5 GW are produced by generators that are more than 50 years old. This figure is expected to double by 2025 in the absence of new generation being built to replace aging assets. Accelerated or unplanned retirements can present challenges to system reliability. Furthermore, the preliminary results of the 2016 *RNA* show that if the remaining nuclear generation units on the system were to deactivate, NYISO would see immediate resource adequacy needs.

[97] NYISO Transmission Expansion and Interconnection Manual; October 2015
[98] NYISO 2014 Comprehensive Reliability Plan; March 2015
[99] NYISO Power Trends: Rightsizing the Grid; 2015

- **Changes to System Load:** The potential for higher-than-forecasted system loads under the 50-50 probability level could expose the system to potential reliability issues, including greater levels of load shedding in the interim operating procedures in some localized areas of the state.
- **Changes to System Resources:** Expected capacity resources (new or upgrades) within the study do not materialize, additional generating units become unavailable or retired beyond those already identified, or capacity resources could decide to offer into other markets and, therefore, not be available to New York.
- **Natural Gas Coordination:** Coordinating with New York's reliance on natural gas as the primary fuel for electric generation, NYISO is performing four ongoing studies and efforts focused on 1) improving communication and coordination between the sectors; 2) addressing market structure enhancements, such as the closing time of the natural gas markets; 3) providing for back-up fuel (primarily distillate oil) assurance to generation; and 4) addressing the electric system reliability impact of the sudden catastrophic loss of gas.
- **Federal and State Environmental Regulations:** The five regulatory programs with the largest reliability risk potential include: 1) facility specific operational limitations, 2) the Cross State Air Pollution Rule (CSAPR) cap and trade program for NOx and SO2, 3) the Mercury and Air Toxics Standards (MATS) for hazardous air pollutants from new and existing coal and oil-fired units, 4) the CPP, which is the proposed EPA greenhouse gas standards for existing sources, and 5) the revised Ozone National Ambient Air Quality Standard (NAAQS).

Furthermore, the New York State CES seeks to reduce the state's carbon dioxide emissions by 40 percent; the CES seeks to do this through increasing the amount of renewable energy generation in New York State to 50 percent of total energy production by 2030. The New York State Department of Public Service staff estimates that to meet the CES's goals by 2030, energy from renewables would need to increase by 33,700 GWh from the current levels. Based on historical demonstrated capacity factors, NYISO estimates that this increase will require the development of approximately 25,000 MWs of solar capacity, approximately 15,000 MWs of wind capacity, or approximately 4,000 MWs of hydroelectric capacity. NYISO continues to study the impacts of the relative capability of intermittent resources to reliably supply power demands and fulfill IRM requirements.

Essential Reliability Services

NYISO is conducting a study on the reliability impacts of the EPA CPP. A portion of this study will examine changes to essential reliability service (ERS) metrics as the resource mix changes, and as the inertia and kinetic energy, as presented in the NERC ERS Task Force Measures Framework Report. This assessment will be performed by compiling the inertia and MVA rating for all NYBA generators and tabulating in each hour, based on future model run year output, which generators are operating and the aggregate system kinetic energy that corresponds.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established reserve margin requirement is applied as the Reference Margin Level.[100]

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled, based on historic performance and historic weather data

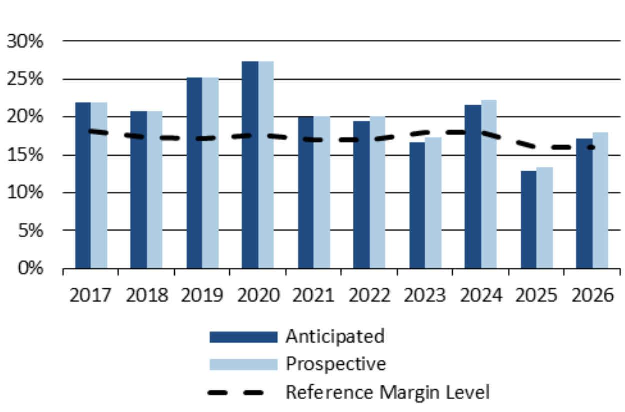
Planning Considerations for Solar Resources
Modeled, based on historic weather data

Footprint Changes
N/A

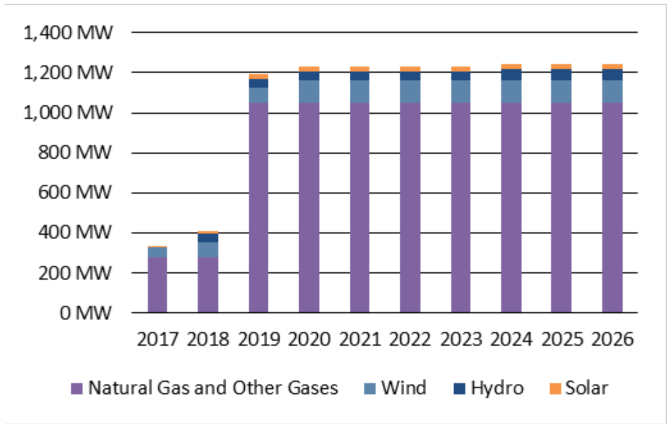
Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	22,680	22,519	22,357	22,192	22,479	22,255	22,190	22,194	22,326	22,265
Demand Response	680	641	601	601	601	601	804	1,007	1,210	1,210
Net Internal Demand	22,000	21,878	21,756	21,591	21,878	21,654	21,386	21,188	21,116	21,056
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	26,822	26,431	27,216	27,478	26,235	25,872	24,957	25,773	23,819	24,646
Prospective	26,822	26,431	27,216	27,478	26,290	26,000	25,085	25,901	23,947	24,837
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	21.92%	20.81%	25.10%	27.27%	19.92%	19.48%	16.70%	21.64%	12.80%	17.05%
Prospective	21.92%	20.81%	25.10%	27.27%	20.17%	20.07%	17.30%	22.25%	13.41%	17.96%
Reference Margin Level	18.13%	17.31%	17.13%	17.67%	17.00%	17.00%	18.00%	18.00%	16.00%	16.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	278	-	676	-
Prospective	-	-	-	-	-	-	150	-	548	-

[100] Ontario IESO, for its own assessments, treats demand response as a resource instead of as a load modifier. As a consequence, the net internal demand, planning reserve margins, and target reserve margin numbers differ in IESO reports when compared to NERC reports. The Ontario reports would show lower reserve margins.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The Ontario Area is a summer peaking area. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[101]

- **Results Trending:** The previous study, *NERC RAS Long-Term Reliability Assessment – NPCC Region*,[102] estimated an annual LOLH = 0.0 hours per year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 forecast 50/50 peak demand forecast is 218 MW greater in this assessment than reported in the previous assessment. This reflects the interplay of economic expansion, population growth, increasing penetration of electrically powered devices, conservation programs, increasing embedded generation output, and energy price changes that act to reduce the amount of grid-supplied electricity needed. There is no change in the estimated LOLH and EUE between the two assessments mainly due to the contributions of various DR programs, operating procedures, and tie benefits.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The Ontario IESO, in its own assessments, treats DR as a resource instead of a load modifier. As a consequence, reserve margin calculations are lower in IESO reports when compared to NERC assessments.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[103]

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[101] NPCC: Regional Reliability Reference Directory #1

[102] NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015

[103] NPCC Library - Resource Adequacy

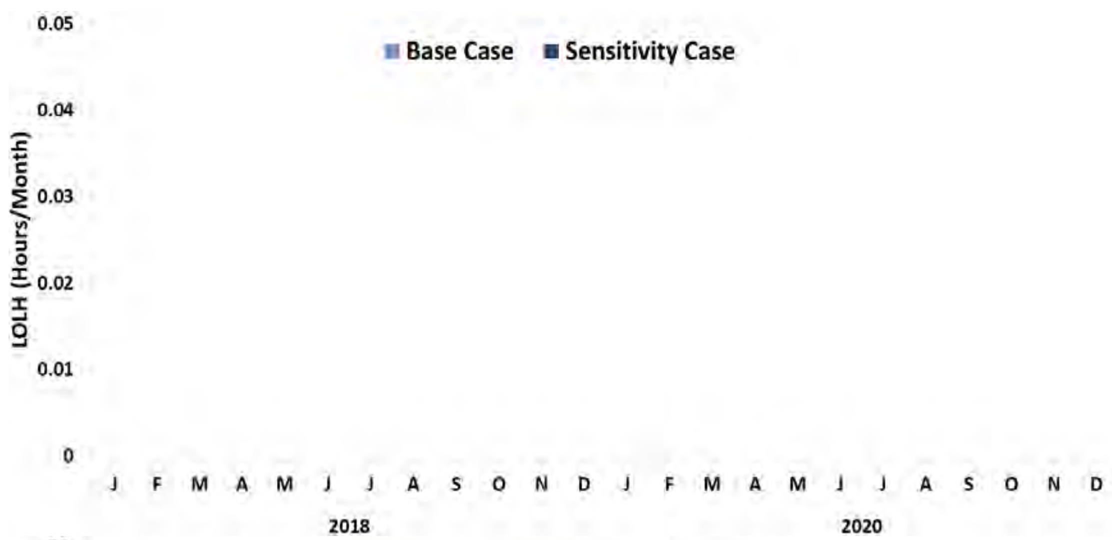
Base Case Study

There was no significant LOLH or EUE observed for the Base Case study for either 2018 or 2020. Anticipated Reserve Margins are above 17.31 percent and 17.76 percent in 2018 and 2020, respectively.

Sensitivity Case Study

LOLH values are not significant in this case, and the EUE are negligible: .004 and .074 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above the Base Case reference reserve margin in both years. The greatest contribution to EUE occurs during the peak (summer) monthly period.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	20.81	25.10	18.4	22.2
Prospective	20.81	27.27	-	-
Reference	17.31	17.67	-	-
ProbA Forecast Planning	20.8	27.3	18.4	22.2
ProbA Forecast Operable	4.7	11.9	2.6	7.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.004	0.074
EUE (ppm)	0.000	0.000	0.000	0.001
LOLH (hours/year)	0.000	0.000	0.000	0.000



Supply-Demand Balance and Resource Adequacy

Ontario has enough confirmed planned resources (Tier 1) to meet its Reference Margin Levels in all years except for 2023 and 2025. The analysis shows that the earliest need for additional resources may arise in 2023, and that need is expected to be less than 1 GW. Ontario possesses a range of options to address these needs, including market-based mechanisms and capacity imports.

Over the next ten years, Ontario expects grid-connected electricity demand to decline slightly, both in terms of annual energy and summer peak. While modest economic and population growth is expected, increases in demand are expected to be offset by three key factors:

- Growth in distributed generation, driven in large part by government renewable capacity targets and feed-in tariff programs
- 13 TWh of annual conservation savings (incremental to today's demand levels), driven by updates to codes and standards, conservation incentives, and energy efficiency programs
- The continuing success of peak-reduction incentive programs that are already in-place, such as the Industrial Conservation Initiative and time-of-use rates

Over the past ten years, Ontario has invested heavily in electricity infrastructure to enable the phase-out of coal-fired generation and to reduce the carbon footprint of Ontario's electricity supply. The next ten years will also be marked by further change as the system continues its transformation.

Retirements

Pickering nuclear station, with an installed capacity of about 3 GW or 8.6 percent of Ontario's current supply, is expected to be decommissioned between 2022 and 2024.

Nuclear Refurbishments

8.5 GW of nuclear supply at Darlington and Bruce nuclear plants is expected to undergo mid-life refurbishment between 2016 and 2033. Much of this occurs during the assessment period, with up to 4 nuclear unit's off-line during a refurbishment outage simultaneously during the peak refurbishment year. The development of the refurbishment programs was supported by Ontario's past experience and the plan will be implemented in a way that minimizes risk.

Capacity Additions

Ontario expects to add 3.5 GW of grid-connected generating capacity over the assessment period, of which just over 1 GW is natural gas, and the balance is renewable resources such as wind and solar.

Demand Response

IESO continues to transition the procurement of DR from capacity-based DR (CBDR) programs to an annual DR auction. This is a transparent and cost-effective way to select the most competitive providers of DRs while ensuring that all providers are held to the same performance obligations. The first DR competitive auction was held in December 2015, where nearly 400 MW were procured. Ontario currently has approximately 550 MW of CBDR and DR Auction capacity under contract, a similar level to that in last year's LTRA. At minimum, this level of capacity will be maintained through subsequent auctions with additional capacity-based DR expected to be acquired between 2021 and 2025, consistent with government targets, to a total of 1,200 MW by 2025.

Ontario currently has over 1.1 GW of DR capability. It is anticipated that DR capacity will reach 1.8 GW by the end of the assessment period, consistent with government targets.

Distributed Generation

Over the assessment period, a further 1.1 GW of variable generation is expected to be added to the distribution system. This is in addition to the 3.7 GW of variable generation currently connected at the distribution level.

Transmission Outlook and System Enhancements

Transmission planning to address changes to the supply mix and ensure reliability throughout the province is ongoing. Two major system enhancement projects are underway: 1) a new 230 kV double-circuit East-West Tie line in Northwestern Ontario and 2) a new 500 to 230 kV transformer station (TS), Clarington TS, in the Eastern portion of the Greater Toronto Area. The expected in-service date for the new East–West Tie line is 2020, and the Clarington transformer station is scheduled to be in service in 2018.

Planning studies are being finalized to manage the loading on the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS, which are forecasted to be exceeded by 2022. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station (SS) with eight 230 kV circuit terminations and 12 km of new double-circuit line sections connecting the new Milton TS to Hurontario SS.

Southern Ontario experiences high voltages during light load periods, and with the planned shutdown of Pickering GS and the removal of its reactive absorption capability, the situation is expected to persist. Planning work for the installation of new voltage control devices is being finalized.

Long-Term Reliability Issues

With the growth in distributed generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected variable generation and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

The introduction of variable generation (e.g., solar and wind) and the removal of flexible generation (e.g., coal), combined with lower demand and limitations in operational flexibility of gas and hydro resources, have added new challenges to maintaining a reliable system. The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation, and additional grid voltage control. It is important that the supply mix remain robust in meeting industry planning standards, flexible to meet the ever-changing demands of system operations, and balanced in managing inherent risks, such as fuel security and critical infrastructure needs. To that end, the IESO has launched an initiative to augment resource flexibility and issued a request for information for additional regulation service in June 2016. IESO has an energy storage pilot program underway to test the capability of storage technologies to provide grid services as well. Activities are also underway with transmitters to plan and install additional dynamic and static voltage control devices to help with voltage control.

Increasing amounts of variable generation, coupled with relatively flat demand levels, have contributed to a rise in surplus baseload generation (SBG) in Ontario. Over the next few years, more variable generation is expected, but the effects on SBG will be tempered by the impact of the planned nuclear refurbishments and retirements. The IESO has mechanisms in place to manage SBG, including economic exports, wind and solar dispatch, and nuclear maneuvers or shutdowns.

NPCC- Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties, radial generation, or load to and from neighboring systems.

Summary of Methods and Assumptions

Reference Margin Level
Reference margin levels are drawn from the Québec Area *2015 Interim Review of Resource Adequacy*, which was approved by NPCC's Reliability Coordinating Committee in December 2015.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Winter

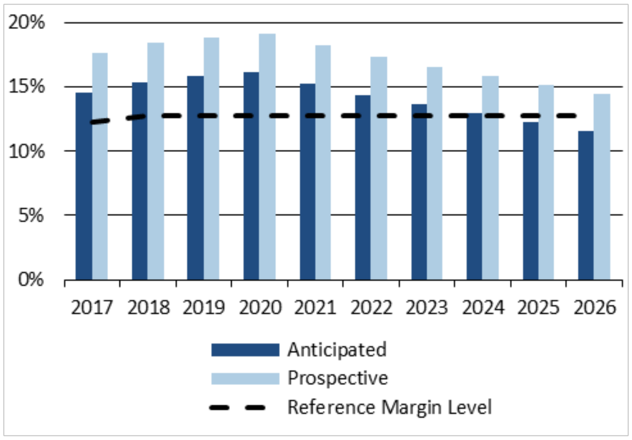
Planning Considerations for Wind Resources
On-peak contribution is approximately 30 percent of the total

Planning Considerations for Solar Resources
N/A

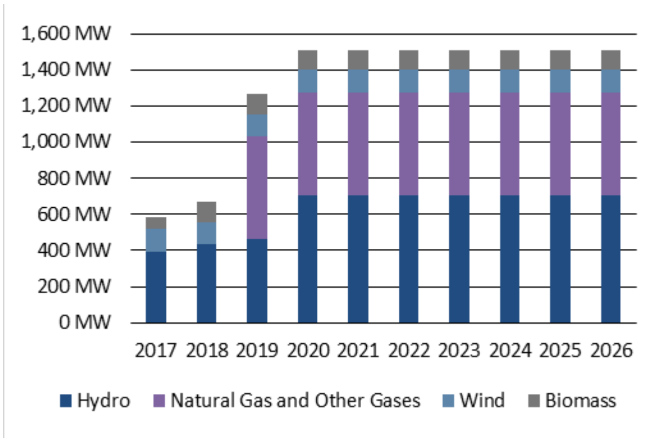
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	38,150	38,521	38,875	39,130	39,415	39,689	39,939	40,167	40,388	40,625
Demand Response	2,168	2,238	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318
Net Internal Demand	35,982	36,283	36,557	36,812	37,097	37,371	37,621	37,849	38,070	38,307
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	41,217	41,847	42,348	42,746	42,746	42,746	42,746	42,746	42,746	42,746
Prospective	42,317	42,947	43,448	43,846	43,846	43,846	43,846	43,846	43,846	43,846
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	14.55%	15.34%	15.84%	16.12%	15.23%	14.38%	13.62%	12.94%	12.28%	11.59%
Prospective	17.61%	18.37%	18.85%	19.11%	18.19%	17.33%	16.55%	15.85%	15.17%	14.46%
Reference Margin Level	12.20%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	159	426
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Québec is a winter peaking area. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[104]

- **Results Trending:** The previous study, *NERC RAS Long-Term Reliability Assessment – NPCC Region,*[105] estimated an annual LOLH = 0.0 hours per year and a corresponding EUE equal to 0.0 for the year 2018. The forecast 50/50 peak demand for 2018 was lower than reported in the previous study with a slightly higher estimated forecast planning and forecast operable reserve margins. As a result, there is no change in the estimated LOLH and EUE in this year's study.

- **Probabilistic vs. Deterministic Reserve Margin Results:** Québec's Reference Reserve Margin is determined based on the NPCC resource adequacy criterion; results indicate a Reference Reserve Margin of 12.7 percent.[106]

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[107]

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104 NPCC: Regional Reliability Reference Directory #1
105 NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015
106 NPCC 2015 Québec Balancing Authority Area Interim Review of Resource Adequacy; December 1 2015
107 NPCC Library - Resource Adequacy

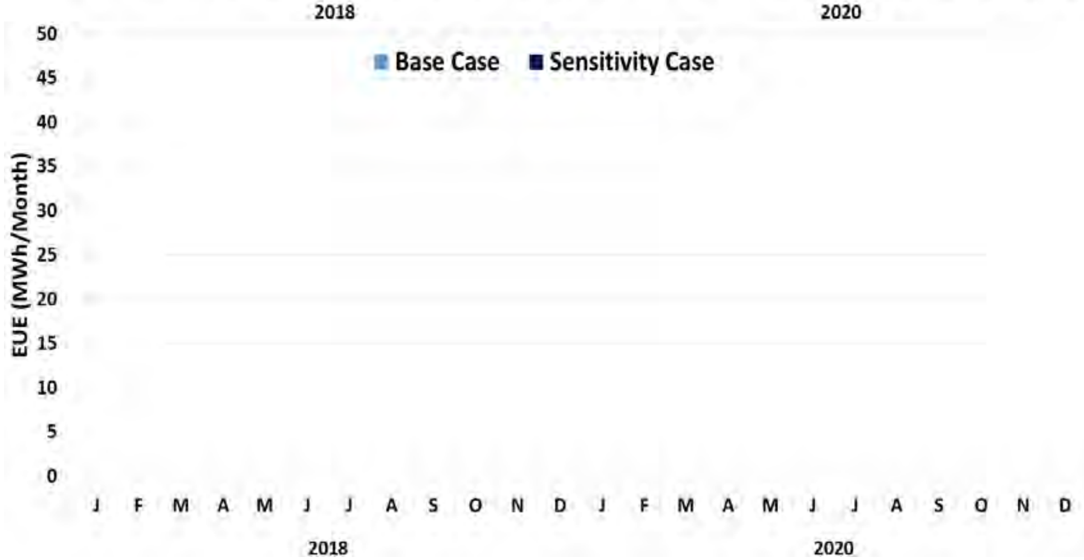
Base Case Study

No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are above the Reference Reserve Margins for 2018 and 2020, respectively.

Sensitivity Case Study

No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are near the Reference Reserve Margins.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	14.55	15.84	12.2	11.1
Prospective	17.61	18.85	-	-
Reference	12.7	12.7	-	-
ProbA Forecast Planning	14.5	15.8	12.2	11.1
ProbA Forecast Operable	12.9	14.2	10.6	9.6
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



Demand, Resources, and Planning Reserve Margins

The Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period. Under the Prospective Reserve Margin, a total of 1,100 MW of expected capacity imports are planned by the Québec Area. These purchases have not yet been backed by firm long-term contracts; however, on a yearly basis, the Québec Area proceeds with short-term capacity purchases (UCAP) if needed to meet its capacity requirements.

The Québec area demand forecast average annual growth is 0.7 percent during the 10-year period; this is similar to last year's forecast. Total internal demand is calculated for the Québec area as a single entity and the area's peak demand forecast is coincident.

DR programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs (for large industrial customers), totaling 1,748 MW for the 2017–2018 winter period. The total on-peak DR for the 2026–2027 winter period is projected to be 2,318 MW.

In 2015, the generating station La Romaine-1 was integrated for a total of 270 MW of new added hydro capacity. Work is under way on the La Romaine-3 (395 MW) development which will be fully operational in 2017. Some preparatory work has also begun on the La Romaine-4 (245 MW) development, which will be fully operational in 2020. The integration of small hydro units also account for 83 MW of new capacity during the assessment period. For other renewable resources, about 350 MW (105 MW on-peak value) of wind capacity and 5 MW of biomass have been added to the system since the beginning of 2015. Additionally, 663 MW (199 MW on-peak value) of wind capacity and 128 MW of biomass are expected to be in service by 2018.

The Québec Area will support firm capacity sales totalling 750 MW during the 2017–2018 winter peak period, declining to 145 MW for the 2020–2021 winter period and after.

Transmission Outlook and System Enhancements

This section reviews several major transmission projects currently underway.

The Romaine River Hydro Complex Integration

Construction of the Romaine River Hydro Complex project is presently underway. Its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in December 2014, and Romaine-1 (270 MW) in December 2015. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017–2020 at Montagnais 735/315-kV substation. The Québec area is reiterating its commitment to sustainable development by focusing on renewable energy at the Romaine complex, which will help meet current needs without jeopardizing the energy supply of future generations.

Main system upgrades for this project have required construction of the new Aux Outardes 735-kV switching station, located between existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station, and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua substations. This upgrade has been commissioned in Summer 2015.

The Chamouchouane–Montréal 735-kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735-kV line in the near future in order to meet the Reliability Standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km or 250 miles). The new 735kV substation is required to fulfill two objectives: 1) providing a new source of electricity supply on the north shore of Montreal and 2) connecting the new 735kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line is scheduled for the 2018–2019 winter peak period. Public information meetings have been held and construction phase has begun.

Upcoming Regional Projects

Other regional substations and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas. There are another dozen projects in other areas with in service dates from 2016 to 2020, consisting mostly of 315/25-kV and 230/25-kV distribution substations to replace 120-kV and 69-kV infrastructures.

Long-Term Reliability Issues

While technical developments in recent years have contributed to create a more reliable system, sustainable system reliability may be challenged by emerging issues, such as potential operational issues due to the changing resource mix. In Québec area, wind generation capacity has increased by 2,500 MW over the five last years, but the area's total installed capacity is still mainly composed of large reservoir hydro complexes (more than 90 percent). These complexes can react quickly to adjust their generation output and meet the sharp changes in electricity net demand. The forecasted change to resource mix is not expected to have any influence on the ramp rate trends or any other reliability issue.

PJM

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM companies serve 61 million people and cover 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Summary of Methods and Assumptions

Reference Margin Level

The PJM RTO reserve requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Method

PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency. Distributed solar generation is now reflected in the historical load data used to estimate the models. This is done with a separately-derived solar forecast that is used to adjust load forecasts.

Peak Season

Summer

Planning Considerations for Wind Resources

Initially, 13 percent of nameplate replaced with historic information tracked over the peak period

Planning Considerations for Solar Resources

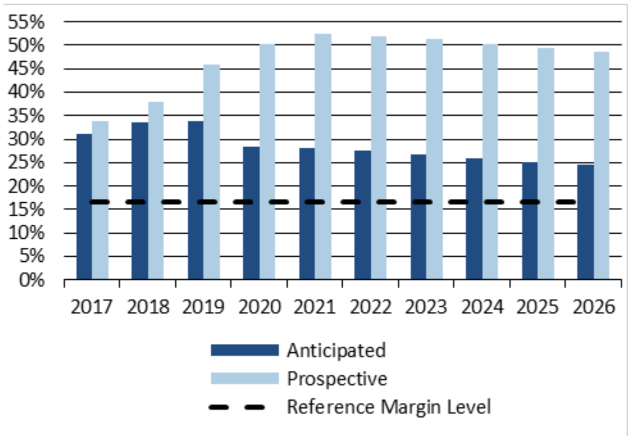
Initially, 38 percent of nameplate replaced with historic information tracked over the peak period

Footprint Changes

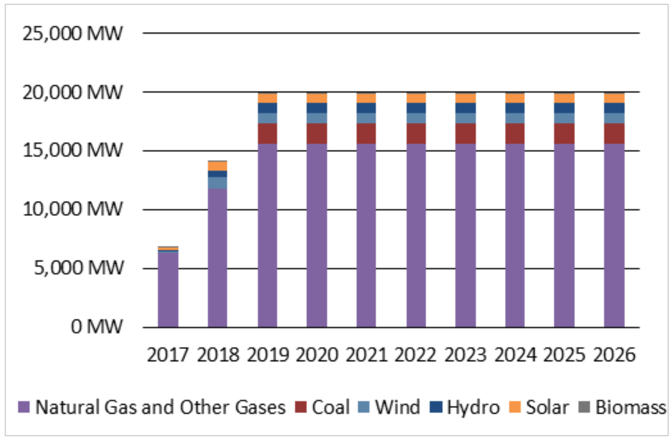
The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891
Demand Response	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524
Net Internal Demand	145,266	146,936	147,923	153,471	153,934	154,550	155,525	156,513	157,448	158,367
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	190,456	196,163	197,903	197,178	197,178	197,178	197,178	197,178	197,178	197,178
Prospective	194,577	202,598	215,980	230,792	234,816	234,849	235,353	235,353	235,353	235,353
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31.11%	33.50%	33.79%	28.48%	28.09%	27.58%	26.78%	25.98%	25.23%	24.51%
Prospective	33.95%	37.88%	46.01%	50.38%	52.54%	51.96%	51.33%	50.37%	49.48%	48.61%
Reference Margin Level	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The probabilistic assessment was carried out in GE-MARS using Monte Carlo simulation. Internal and external load shapes were from year 2002 (Summer) and 2004 (Winter) adjusted to match monthly and annual peak forecast values from the 2016 PJM load forecast. Data on individual unit performance is from the period 2011–2015. PJM was divided in five subareas interconnected using a transportation/pipeline approach. External areas were modeled using a detailed representation (NPCC) and at planned reserve margin (MISO, TVA, VACAR).

- **Modeling:** Load forecast uncertainty was modeled on a monthly basis using a normal distribution discretized in seven steps[108]. Demand side management (DSM) was modeled as an emergency operating procedure as most of the DSM in PJM is emergency DSM. Intermittent generators were modeled as a regular resource at their respective capacity values (average capacity value for wind is 13 percent while for solar is 38 percent). Firm exports/imports were explicitly modeled while the limits on the transportation/pipeline interfaces were calculated based on a First Contingency Total Transfer Capability (FCTTC) analysis.

- **Results trending:** The 2018 LOLH and EUE in the 2016 ProbA are smaller than the corresponding values reported in the 2014 ProbA:
  - 2018 LOLH in 2016 ProbA = 0.000 hrs/year vs. 2018 LOLH in 2014 ProbA = 0.009 hrs/year
  - 2018 EUE in 2016 ProbA = 0.003 MWh/year vs. 2018 EUE in 2014 ProbA = 9.300 MWh/year

  This difference can be explained by the larger planning and operable reserves for 2018 in the 2016 ProbA compared to those in the 2014 ProbA. The increase in 2018 reserves is due to a reduction in net internal demand and an increase in forecast capacity resources. In particular, the increase in forecast capacity resources is due to the fact that, by the time the 2014 ProbA was run, none of the 2018 capacity market auctions had been cleared. In contrast, the forecast capacity resources for 2018 considered in the 2016 ProbA include capacity secured via capacity market auctions.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For Summer 2018 and Summer 2020, the probabilistic reserve margin in slightly lower than the deterministic value due to 2,500 MW of on-peak capacity derates as a result of above average summer ambient conditions.

[108] PJM: Load Forecasting and Analysis; June 2016

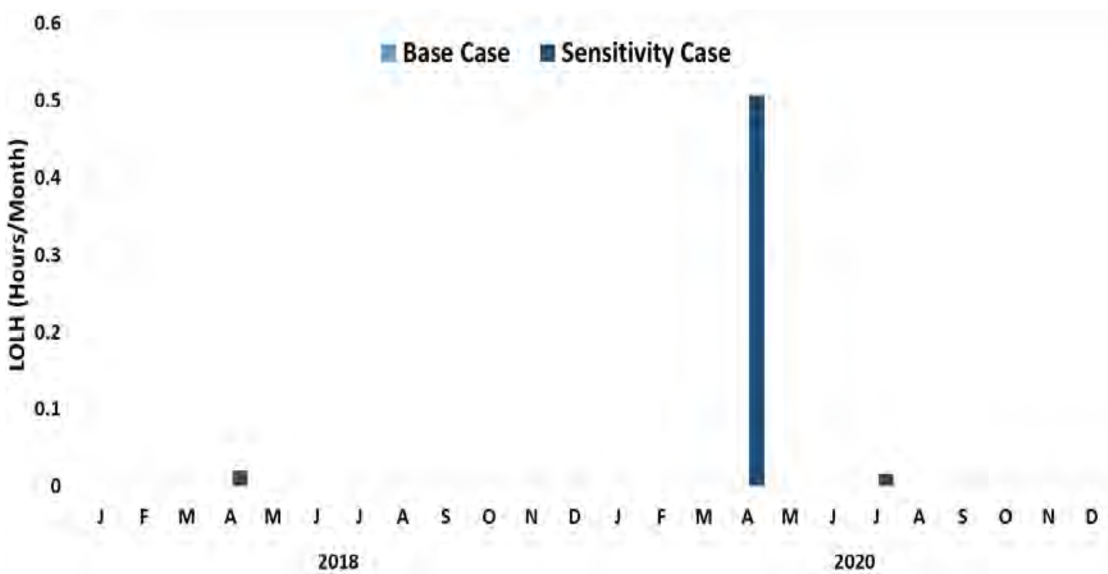
Base Case Study

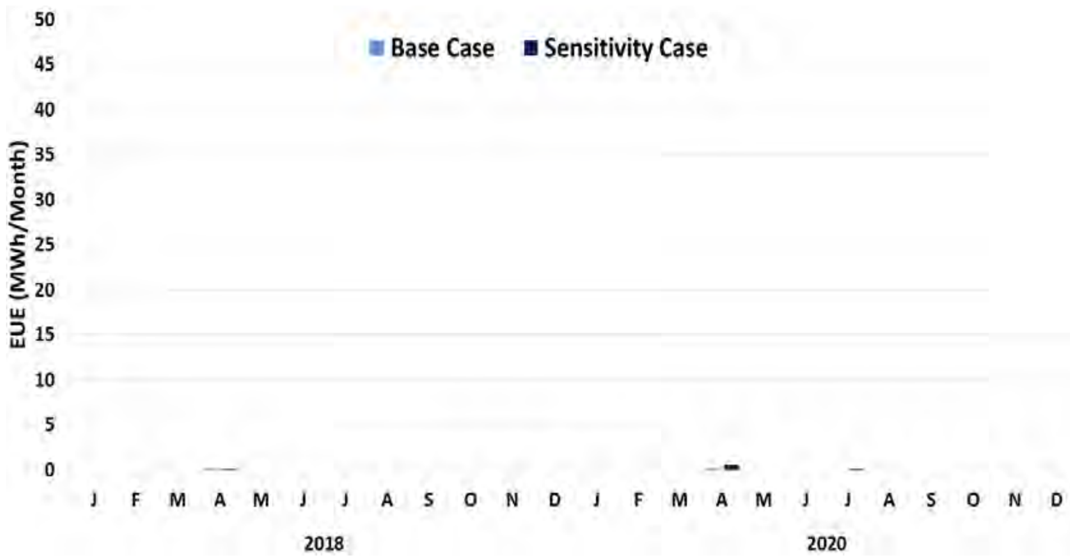
- LOLH is zero for both 2018 and 2020 due to large forecast planning reserve margins (significantly above the reference value of 16.5 percent).
- EUE is virtually zero (though technically nonzero) for both 2018 and 2020. The only month that contributes a discernible amount of EUE in both years is April due to planned maintenance and large load uncertainty for some of the areas within PJM.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	33.5	28.5	30.7	23.4
Prospective	37.9	50.4	35.0	44.5
Reference	16.5	16.5	16.5	16.5
ProbA Forecast Planning	31.8	26.8	29.1	21.9
ProbA Forecast Operable	20.8	16.1	18.3	11.6
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.003	0.001	0.020	0.523
EUE (ppm)	0.000	0.000	0.000	0.001
LOLH (hours/year)	0.000	0.000	0.000	0.001

Sensitivity Case Study

- LOLH is still zero for 2018. For year 2020, LOLH exhibits a very mild uptick (i.e., 0.001 hours per year) during April due to a large amount of planned maintenance and large load uncertainty for some of the areas within PJM.
- EUE is slightly higher than under the Base Case for both 2018 and 2020 but still very close to zero. Months that contribute to the EUE in the Sensitivity Case are April (due to the reasons mentioned above explaining the LOLH uptick in 2020) and July (where the PJM annual peak occurs).





Summary

The PJM RTO reserve requirement, as calculated by PJM, is 16.4 percent for the 2016/2017 planning period, which runs from June 1, 2016 through May 31, 2017. The PJM RTO reserve requirement is 0.8 percentage points higher this year compared to the 2015/2016. About three-eighths of this increase can be attributed to changes in the PJM load model: shorter historical time period, greater energy efficiency and distributed generation, and more granular weather monitoring. Another three-eighths can be attributed to worse performance by the generation units while the remaining quarter is due to reduced emergency imports from the world (i.e., outside the PJM area). Since the modeling of the PJM peak is nearer to the world peak, there is a lack of diversity with the world peak. A 16.5 percent PJM RTO reserve requirement is applicable for the rest of the assessment period. PJM RTO will have an adequate Anticipated Reserve Margin though the entire assessment period. The prospective margin is also adequate for the entire assessment period.

Since the 2015 report, PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response to weather across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency. Distributed solar generation is now reflected in the historical load data used to estimate the models with a separately-derived solar forecast used to adjust load forecasts.[109]

The winter load forecast has smaller changes compared to the summer load forecast. This is due to two impacts acting against one another to minimize changes to previous forecasts: 1) the result of shortening the historical period that PJM uses to produce weather scenarios and 2) this lowered the resulting winter forecast. The other impact is related to refinements to the weather specification that addressed the previous model's tendency to understate the elasticity of load to weather at peak conditions.

The PJM Capacity Performance initiative (a PJM program to incentivize better generator performance) starts to show up in future DR accounting since DR is considered capacity in PJM. This program actually decreases DR by more than half since performance is required the entire year and some DR programs that include air conditioning reductions cannot reduce air conditioning load that is not there. A PJM committee is investigating a seasonal aspect to capacity that may influence the amount of DR accepted by PJM in the future.

PJM has begun to track residential PV installations through the PJM Generation Attribute Tracking System (GATS) since there is an effect on the PJM load forecast. Estimates (of the effect) for 2016 are 574 MW, and this increases

[109] Detailed information on the development of the distributed solar generation forecast can be found on the PJM website.

to 1,523 MW in 2026. This is less than one percent of the PJM forecasted peak load, so these energy sources will have little effect on adequacy or reliability in PJM. PJM Environmental Information Services (EIS) operates the GATS. EIS is a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection. The functional design of the GATS has been developed through considerable deliberation of a stakeholder group that included representatives from various state agencies (public utility commissions, environmental protection offices, energy offices, and consumer advocates), market participants, environmental advocates, and PJM staff. The design of the GATS is an "unbundled" certificates-based tracking system. This means that the attributes or characteristics of the generation are separated from the megawatt hour (MWh) of Energy and recorded onto a certificate after the MWh of energy is produced.

Variable resources are only partially counted for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors: 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor. Biomass and hydro are counted at 100 percent of reported existing-certain resources because these resources are typically only fully utilized over the peak period of the day. Some run-of-the-river hydro capacity has always been reported as a lower value than total plant nameplate in PJM due to the full capability of the plant not typically being available.

PJM has 6,748 MW of firm imports and 1,395 MW of firm exports (resulting in a net firm import of 5,353 MW) scheduled for the 2016–2017 planning period (June 1, 2016 to May 31, 2017). Firm imports drop to 5,364 MW, 1,413 MW of firm exports with a net firm import of 3,951 MW in 2017–2018 planning period. PJM has 4,126 MW of firm imports, 1,395 MW of firm exports with a next firm import of 2,731 MW scheduled for the 2018–2019 planning period. The same imports and exports as the 2018–2019 planning period are expected for the remaining years of the assessment.

PJM has recently experienced below average winter temperatures. PJM's winter peak reliability analysis indicates that the transmission system is capable of delivering the system generating capacity at winter peak.

PJM has experienced some thermal overload problems during light load conditions with relatively high wind generator output. PJM's light load reliability analysis[110] ensures that the transmission system is capable of delivering the system generating capacity during light load conditions. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level like high wind output.

Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas that impact PJM facilities are based on statistical averages for previous off-peak periods. The flowgates ultimately used in the light-load reliability analysis are determined by running all contingencies maintained by PJM planning. These are also determined through monitoring all PJM market monitored facilities and BPS facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5, and P7. NERC TPL P0, normal system conditions will also be studied.

There has been a steady retirement of coal resources that are being replaced by combined cycle natural-gas-powered resources. No difference has been seen in net demand ramping variability related to this change in resource mix within PJM.

[110] PJM Analysis of Light Load Historical Data and Light Load Reliability Criterion; July 9, 2015

SERC

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 BAs: Alcoa Power Generating, Inc.—Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

Summary of Methods and Assumptions

Reference Margin Level
Entities within the SERC footprint adhere to state-set targets that vary throughout the footprint. For this assessment, NERC applies a 15 percent Reference Margin Level for all SERC subregions.

Load Forecast Method
Noncoincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
As reported by individual Generator Owners

Planning Considerations for Solar Resources
As reported by individual Generator Owners

Footprint Changes
None to report

SERC-East Assessment Area Footprint

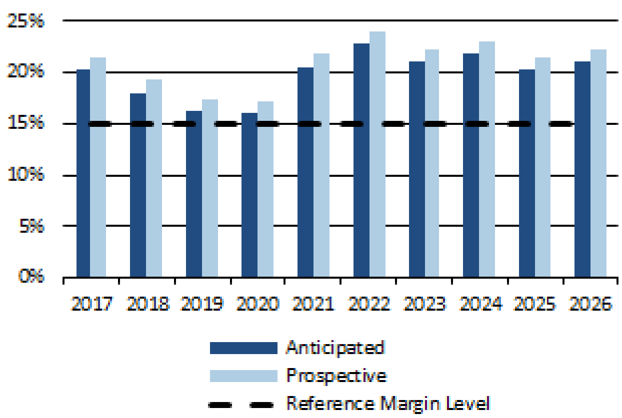
SERC-North Assessment Area Footprint

SERC-Southeast Assessment Area Footprint

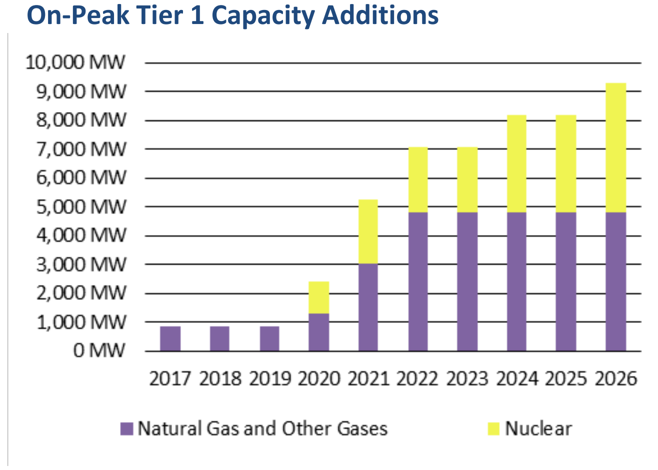
SERC-East

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	43,213	43,999	44,672	45,440	46,126	46,774	47,449	48,053	48,668	49,309
Demand Response	655	663	667	669	672	674	676	679	681	684
Net Internal Demand	42,558	43,336	44,005	44,771	45,454	46,100	46,773	47,374	47,987	48,625
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	51,175	51,139	51,149	51,958	54,798	56,629	56,629	57,746	57,746	58,863
Prospective	51,722	51,686	51,696	52,505	55,345	57,176	57,176	58,293	58,293	59,410
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.25%	18.01%	16.23%	16.05%	20.56%	22.84%	21.07%	21.89%	20.34%	21.06%
Prospective	21.53%	19.27%	17.48%	17.27%	21.76%	24.03%	22.24%	23.05%	21.48%	22.18%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SERC utilizes an 8,760 hourly load, generation, and transmission simulation model that consists of three internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and seven connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the LTRA are input for the model. Then further analysis determines uncertainty parameters such as load forecast uncertainty, generator forced outage rates, etc.

  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[111]

Lowering demand projections in SERC-E (five percent decrease from 2014 to 2016 in the study year 2018 forecast) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area. Although near zero, SERC-E LOLH and EUE for both the 2018 and 2020 Base Cases contribute nearly 100 percent of the totals for the SERC assessment area footprint (SERC-E, SERC-N, and SERC-SE). However, higher excess capacity exists in the other two SERC areas. Furthermore, at anticipated load growth and reserve levels, SERC-E meets an industry standard resource planning criteria of 1-day-in-10-years LOLE in 2020.

- **Results Trending:** From the *2014* to *2016 PRA*, the SERC-E LOLH decreased by approximately 97 percent (0.085 to 0.002) for the same study year 2018. This is primarily driven by the lower projected demand mentioned above as well as the 2016 modeling corrections. The SERC *PRA* model now includes expected firm capacity transfers and improvements to winter historical load profiles.[112] After accounting for lower demand and modeling corrections, SERC-E Base Case 2018 results remain static from 2014.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

[111] SERC Reliability and Performance Analysis (RAPA) homepage

[112] Approximations: 0.085 (2014 PRA- 2018 LOLH) minus 0.080 (decrease load forecasts from 2014 to 2016) minus 0.003 (modeling corrections) equals 0.002

Base Case Study

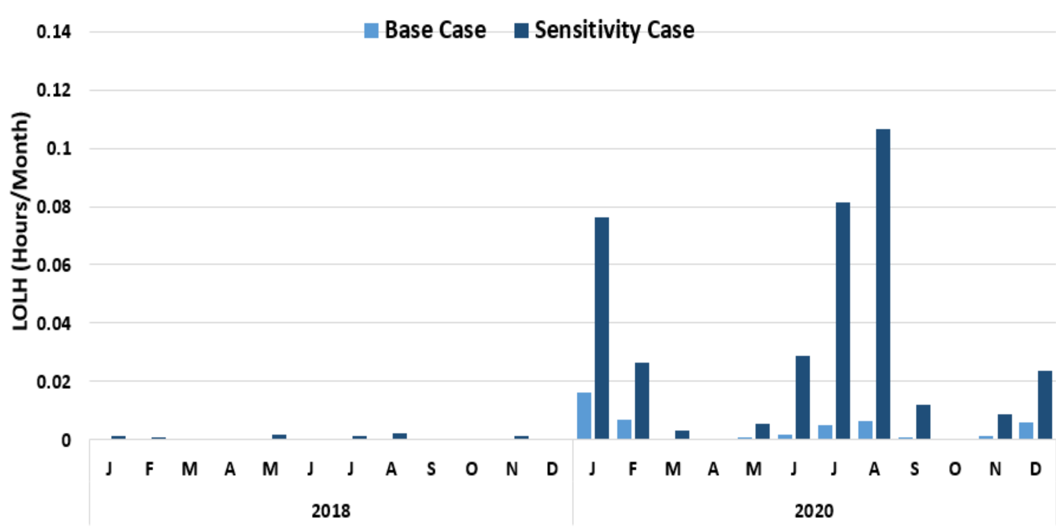
SERC-E LOLH increases to 0.002 hours per year in 2018 and 0.046 hours per year in 2020. EUE increases 1.4 MWh in 2018 and to 49.4 MWh in 2020. This is due to an approximate 3 percent increase in peak demand and minimal increase in anticipated resources. However, the rise of the metrics in 2020 is not concerning considering the MW size of SERC-E. Measures not modeled in the 2016 PRA such as, but not limited to, voluntary and noncontrollable DR, operating procedures to cut nonfirm schedules or maintenance, public appeals, and other mechanisms should mitigate 49.4 MWh of annual EUE within SERC-E.

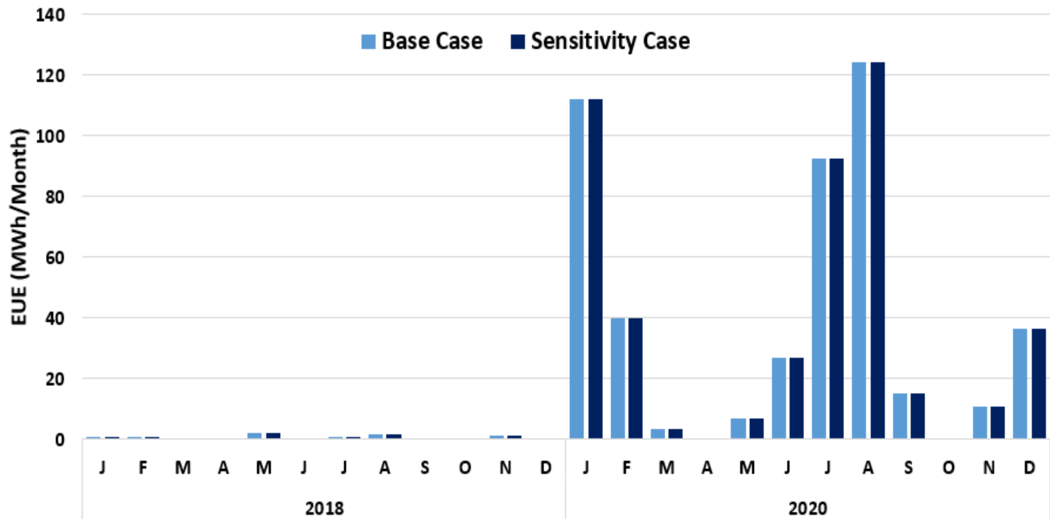
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	18.01	16.05	-	-
Prospective	19.27	17.27	-	-
Reference	15	15	15	15
ProbA Forecast Planning	19.3	19.1	16.9	14.4
ProbA Forecast Operable	11.3	11.2	9.1	6.8
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	1.415	49.394	7.615	457.709
EUE (ppm)	0.006	0.218	0.034	1.983
LOLH (hours/year)	0.002	0.046	0.009	0.373

LOLH and EUE accrue relatively evenly across all months of the year in 2018; however, with increases in demand by 2020, the majority of LOLH and EUE accrues during the peak seasons of summer and winter. Actually, between 60 and 70 percent occurs during the winter months. This is contributable to a high annual 50/50 demand per unit and higher winter load forecast uncertainty due to off-normal events. A recent off-normal event was the 2014 Polar Vortex when annual peaks occurred for many entities within SERC-E during winter months.

Sensitivity Case Study

- SERC-E entities expect a 1.44 percent compound annual growth rate (CAGR). The NERC Sensitivity Case doubles the SERC-E CAGR to 2.90 percent. In this load growth scenario, SERC-E LOLH increases to 0.009 hours per year in 2018 and 0.373 hours per year in 2020. EUE increases 7.6 MWh in 2018 and to 467.7 MWh in 2020.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

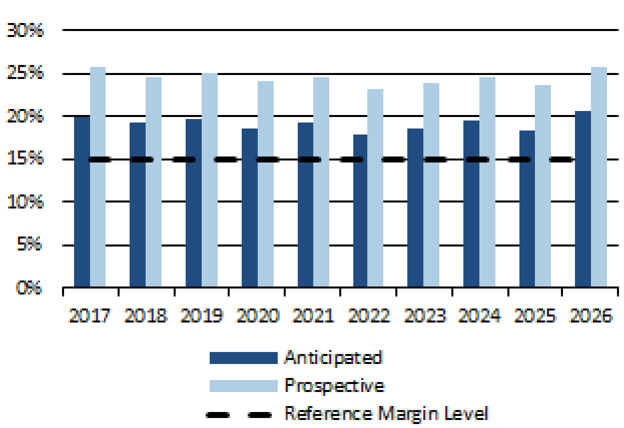




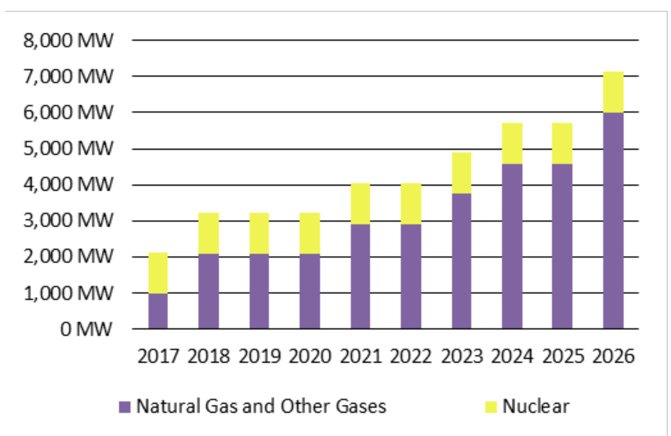
SERC-North

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	42,540	42,955	43,051	43,419	43,800	44,184	44,572	44,954	45,331	45,690
Demand Response	1,789	1,792	1,811	1,813	1,695	1,632	1,588	1,552	1,549	1,544
Net Internal Demand	40,751	41,163	41,240	41,606	42,105	42,552	42,984	43,402	43,782	44,146
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	48,910	49,068	49,337	49,337	50,177	50,177	51,017	51,857	51,857	53,247
Prospective	51,265	51,351	51,620	51,620	52,460	52,460	53,300	54,140	54,140	55,530
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.02%	19.20%	19.63%	18.58%	19.17%	17.92%	18.69%	19.48%	18.44%	20.62%
Prospective	25.80%	24.75%	25.17%	24.07%	24.59%	23.28%	24.00%	24.74%	23.66%	25.79%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SERC utilizes an 8,760 hourly load, generation, and transmission simulation model that consists of three internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and seven connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the LTRA are input for the model. Then further analysis determines uncertainty parameters such as load forecast uncertainty, generator forced outage rates, etc.

  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

  The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[113]

  The demand projections in SERC-N decrease 3 percent in 2018 from the 2014 to 2016 study year. This decrease in demand forecasts continues to increase reserve margin and decrease the resource adequacy measures in the assessment area. Due to a high forecasted reserve margin of 27 percent, SERC-N experiences zero LOLH and near zero EUE for 2018 and 2020 Cases.

- **Results Trending:** From the *2014 PRA* to the *2016 PRA*, the SERC-N LOLH decreased in similar fashion to SERC-E, which was from 0.023 to 0.000 for the same study year of 2018. Again this is largely driven by the decreasing load projections. See SERC-E section for a complete synopsis of changes.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

113 SERC Reliability and Performance Analysis (RAPA) homepage

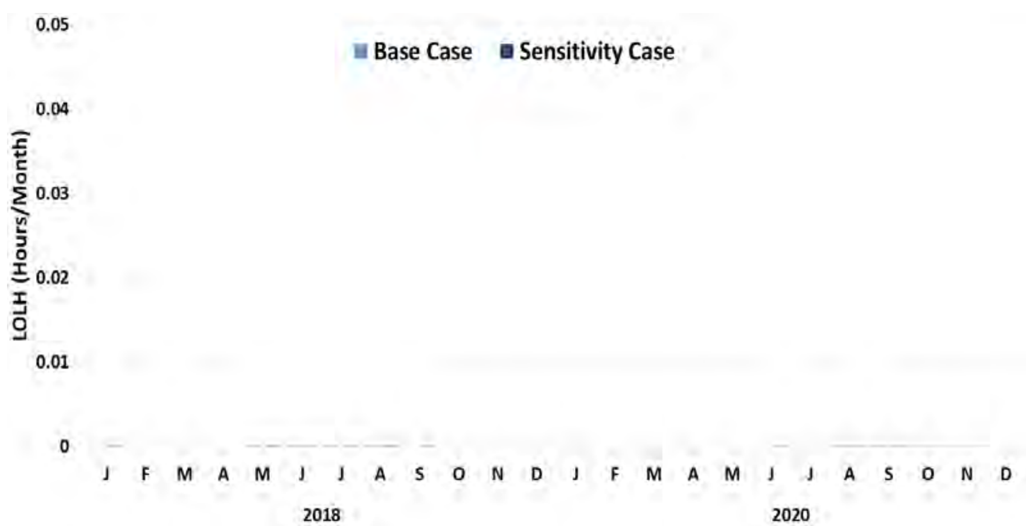
Base Case Study

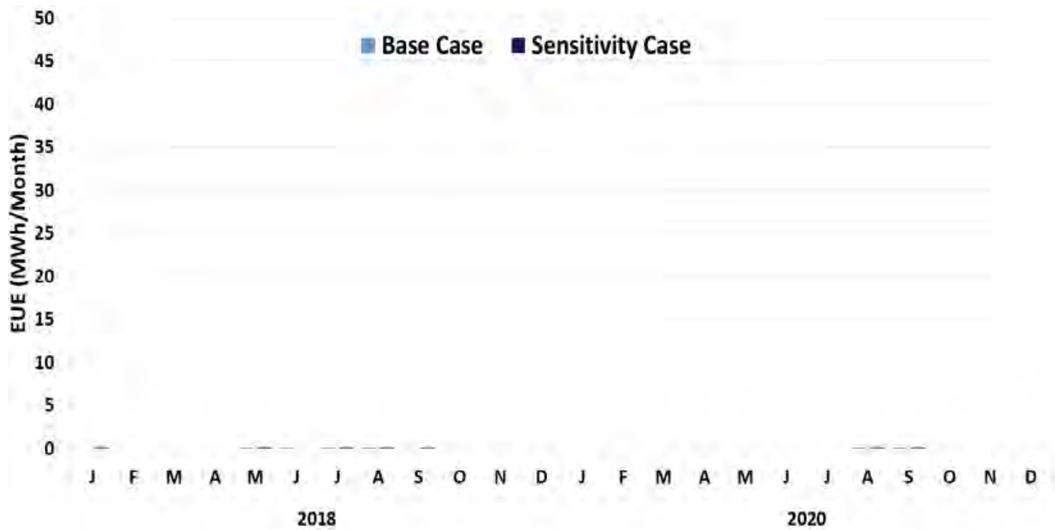
- Zero LOLH and EUE.
- SERC-N entities expect a 0.81 percent CAGR. However, the model results for 2020 base summer yielded near zero percent growth from 2018. However, since the expected growth is below 1 percent, the resulting impact on the indices is negligible.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	19.2	18.58	-	-
Prospective	24.75	24.07	-	-
Reference	15	15	15	15
ProbA Forecast Planning	27.1	27.1	24.4	21.9
ProbA Forecast Operable	18.0	18.0	15.6	13.2
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.173	0.131	1.781	0.780
EUE (ppm)	0.001	0.001	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.003	0.001

Sensitivity Case Study

- The NERC Sensitivity Case doubles the SERC-N CAGR to 1.74 percent. In this load growth scenario, SERC-N LOLH and EUE increase but of minimal consequence to resource adequacy. LOLH increases to 0.003 hours per year in 2018 and 0.001 hours per year in 2020. EUE increases to 1.8 MWh in 2018 and to 0.8 MWh in 2020. The resulting metrics for 2020 are lower than 2018 due to gas-fired generation additions to SERC-N mid-year 2018. Subsequently, the winter months in 2020 reflect lower accrual of LOLH and EUE than in 2018.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

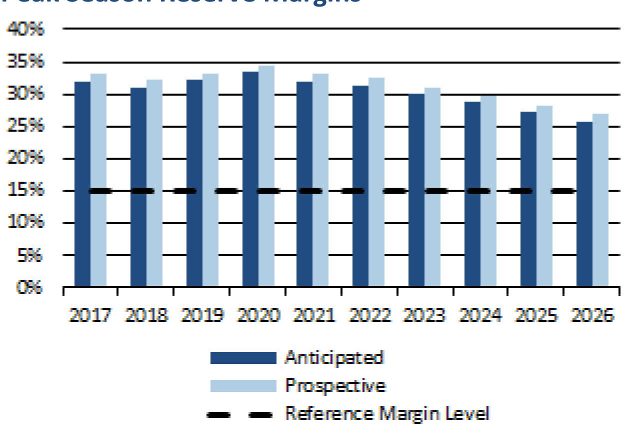




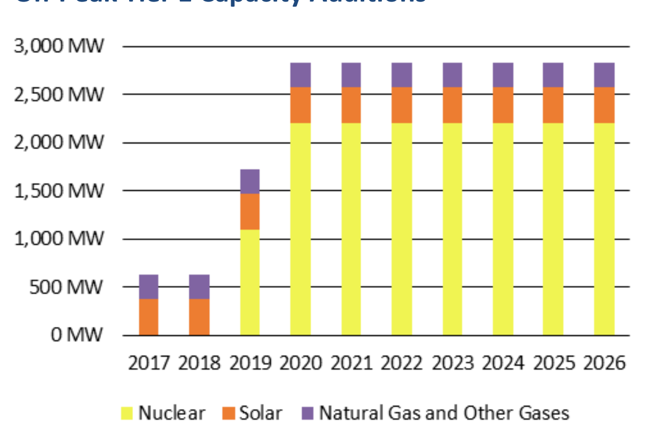
SERC-Southeast

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	47,762	48,124	48,507	48,903	49,325	49,756	50,281	50,859	51,461	52,083
Demand Response	2,228	2,238	2,247	2,256	2,260	2,262	2,265	2,267	2,270	2,273
Net Internal Demand	45,534	45,886	46,260	46,647	47,065	47,494	48,016	48,592	49,191	49,810
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	60,062	60,115	61,101	62,222	62,126	62,396	62,397	62,560	62,562	62,636
Prospective	60,596	60,659	61,645	62,765	62,669	62,939	62,940	63,103	63,105	63,179
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31.91%	31.01%	32.08%	33.39%	32.00%	31.38%	29.95%	28.75%	27.18%	25.75%
Prospective	33.08%	32.20%	33.26%	34.55%	33.16%	32.52%	31.08%	29.86%	28.29%	26.84%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SERC utilizes an 8,760 hourly load, generation, and transmission simulation model that consists of three internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and seven connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the LTRA are input for the model. Then further analysis determines uncertainty parameters such as load forecast uncertainty, generator forced outage rates, etc.

  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

  The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[114]

  Lowering demand projections in SERC-SE (four percent decrease from 2014 to 2016 in study year 2018 forecast) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area. Due to a high forecasted reserve margin of 35 percent, SERC-SE experiences zero LOLH and near zero EUE for 2018 and 2020 Base Cases.

- **Results Trending:** From the 2014 to 2016 *PRA*, the SERC-SE LOLH decreased in similar fashion to SERC-E and SERC-N, which was from 0.029 to 0.000 for the same study year of 2018. This is largely driven by the decreasing load projections. See the SERC-E section for a synopsis of corrected modeling errors from 2014.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

[114] SERC Reliability and Performance Analysis (RAPA) homepage

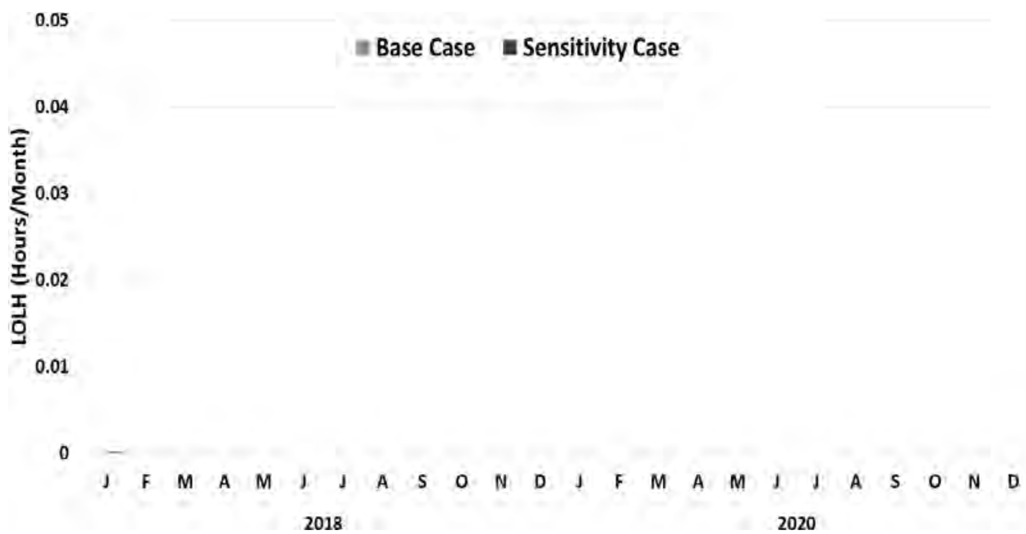
Base Case Study

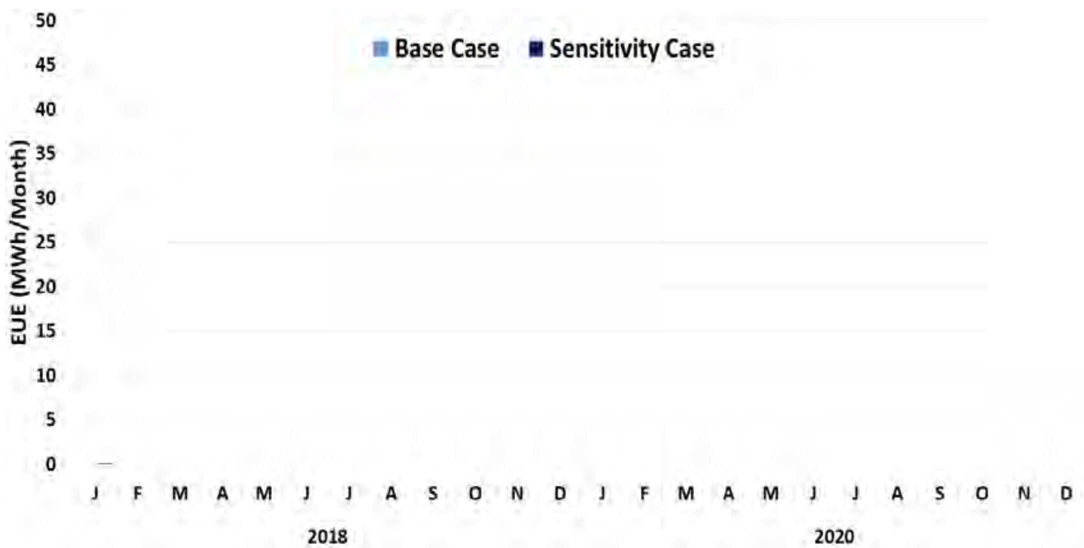
- Zero LOLH and EUE.

Sensitivity Case Study

- SERC-SE entities expect a 1.20 percent CAGR. The NERC Sensitivity Case doubles the SERC-SE CAGR to 2.52 percent. In this load growth scenario, SERC-SE LOLH and EUE still remain zero.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	31.01	33.39	-	-
Prospective	32.2	34.55	-	-
Reference	15	15	15	15
ProbA Forecast Planning	35.1	37.7	32.3	32.1
ProbA Forecast Operable	23.9	26.5	21.3	21.4
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.003	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





SERC Summary

Current projections for the SERC non-RTO assessment area show reserve margins in excess of 15 percent throughout the long-term planning horizon. In the near term (2016–2020), the Region's reserve margin will range from 21.7 to 24.6 percent. The reserve margin decreases that are projected throughout subsequent long-term years (2020–2025) are due to the uncertainty of resource additions. To maintain reserve margin levels, SERC non-RTO entities continuously plan for new capacity, acquire or request power purchase agreements, acquire additional assets, and implant new energy efficiency and DR programs. Uncommitted generating capacity in the SERC Region is not included in comparison with the NERC Reference Reserve Margin; because uncommitted capacity exists in the Region, there will continue to be additional generation above what is reported in the reserve margin. SERC expects this uncommitted capacity to continue to provide additional peaking resources for short-term utility purchases, but the impact on the Region's 2016 summer reserve margin is uncertain. Availability of uncertain capacity cannot be assured because portions of this capacity may be designated to serve load outside of the SERC Region.

Although there is no notable change in demand for the Region, some member entities report slightly decreased demand projections that they attribute to economic factors, DERs, and other energy efficiency programs. Throughout the Region, entities have various programs in place for energy efficiency and conservation: the entities incorporate the projected energy efficiency into the demand forecast, which is reflected back in their reserve margin projections, and entities can also utilize a variety of DR programs as load modifiers during high-load system conditions with implementation times that range from instantaneous to 60 minutes. Upcoming EPA policy changes related to emission standards may limit emergency stationary generator ability to operate without extensive emissions controls in response to a utility's request to reduce demand. This may have an undetermined effect for generators within the Region participating in DR programs.

SERC entities coordinate transmission expansion plans in the Region annually through joint model-building efforts that include the plans of all SERC entities. The coordination of transmission expansion plans with entities outside the Region is achieved through annual participation in joint modeling efforts with the ERAG Multi-regional Modeling Working Group (MMWG). Transmission expansion plans by most SERC entities are dependent on regulatory support at the federal, state, and local levels since the regulatory entities can influence the siting, permitting, and cost recovery of new transmission lines.

The regional long-term studies identified no reliability impacts due to announced retirements or significant generation outages during the assessment period. To better assess highlighted impacts in *NERC's CPP Phase II Assessment* from potential environmental regulations, SERC is coordinating a power-flow study utilizing the Aurora data and assumptions from the phase II assessment. In addition, several transmission upgrades are currently underway to maintain reliability within specific areas of the Region.

With respect to MISO, a settlement agreement was reached between MISO, SPP, and the Joint Parties (TVA, SOCO, LG&E/KU, AECI and PowerSouth). This agreement is now in place (this superseded the ORCA on February 1, 2016) to reliably manage the magnitude of power transfers between MISO South and Midwest. The settlement agreement limits transfers between MISO-South and MISO-Midwest to 2500 MW and MISO-Midwest to MISO-South to 3000 MW in order to limit reliability impacts on neighboring systems. The increase in flow from 1,000 to 2,500/3,000 MW represents a new operating condition that has been studied and experienced under certain historical operating conditions. However, this is a significant change that will be closely monitored in operations for adverse reliability impacts. Although a settlement agreement is in place, SERC is committed to ensuring reliability of the Region and the interconnection. The Region implemented a joint loop flow study initiative with market and nonmarket entities to recreate and study loop flows within the area. The purpose of these studies is to ensure there are not potential IROL conditions that can lead to cascading, separation, or blackout conditions. SERC also plans to track and trend DERs within the Region to assess what possible impacts large penetrations of DERs may have on future BPS reliability.

SPP

The Southwest Power Pool (SPP) Planning Coordinator footprint covers 575,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. The SPP Long-Term Assessment is reported based on the Planning Coordinator footprint, which touches parts of the Southwest Power Pool Regional Entity, Midwest Reliability Organization Regional Entity, and Western Electricity Coordinating Council. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of 18 million people.

Summary of Methods and Assumptions

Reference Margin Level
SPP established target of 12.0 percent

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

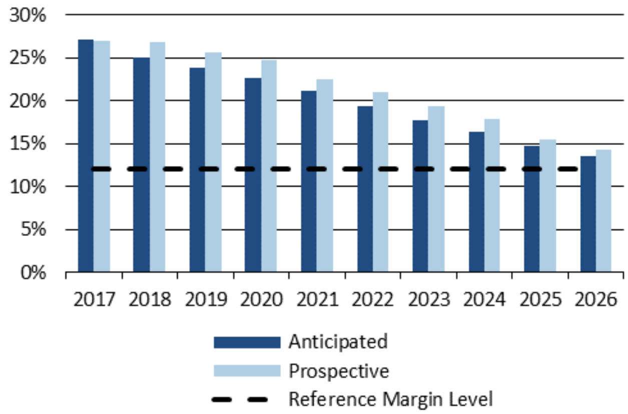
Planning Considerations for Wind Resources
On-peak contribution of 3 percent of nameplate capacity

Planning Considerations for Solar Resources
On-peak contribution of 10 percent of nameplate capacity

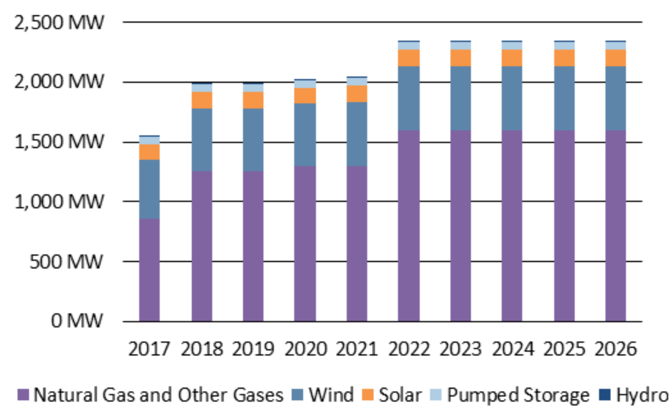
Footprint Changes
The Integrated System (IS), formally part of WAPA, is reporting under the SPP assessment area this year.

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	51,936	52,819	53,235	53,409	53,779	54,336	54,703	55,119	55,581	56,048
Demand Response	753	829	876	898	911	916	913	909	907	904
Net Internal Demand	51,184	51,989	52,359	52,511	52,868	53,420	53,790	54,210	54,674	55,144
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	65,083	65,025	64,868	64,427	64,046	63,735	63,282	63,075	62,681	62,592
Prospective	65,004	65,925	65,768	65,497	64,775	64,665	64,212	63,901	63,101	63,011
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.16%	25.07%	23.89%	22.69%	21.14%	19.31%	17.65%	16.35%	14.65%	13.51%
Prospective	27.00%	26.80%	25.61%	24.73%	22.52%	21.05%	19.37%	17.88%	15.41%	14.27%
Reference Margin Level	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SPP oversees the bulk electric grid and wholesale power market as one consolidated Balancing Authority area on behalf of a diverse group of utilities and transmission companies in 14 states. SPP utilized a nodal modeling technique for the probabilistic assessment. Firm imports and exports of capacity were modelled to reflect the firm transactions reported for the *2016 LTRA*. Assumptions and the accompanying methodology have been thoroughly vetted through the SPP stakeholder process. No events for loss of load occurred in the Base Case and Sensitivity Case studies for the probabilistic assessment.

- **Modeling**: A Monte-Carlo-based software was used in the probabilistic assessment by randomly selecting load forecast uncertainty errors derived from historical probability of occurrence while varying the availability of thermal, hydro, and DR resources. Unit specific ramp rates, outage durations, and equivalent forced outage rates were used when varying the availability of resources in the SPP assessment area. Four thousand iterations were performed for each simulation. The generating resources modelled in the probabilistic assessment reflect the supplied data for the *2016 LTRA*. Existing and Tier 1 resources were included in the probabilistic assessment along with reported confirmed retirements and projected in-service dates of new resources. Wind and solar resources were modelled at historical hourly output values.

  A nodal representation of transmission, load, and generation was modeled for the SPP assessment area, and transmission elements 100 kV and above were monitored to not exceed their normal rating limits. SPP flowgate and interface limitations with generation or load-related issues were considered when performing the simulations. Firm capacity transactions with firm transmission service from assessment areas external to SPP were reflected as to be continuously available during simulations, and nonfirm capacity assistance from neighboring assessment areas were not included. SPP depleted all operating reserves before shedding firm load in the probabilistic assessment.

- **Results Trending:** *The 2014 Probabilistic Assessment* results for SPP indicated 0.0 EUE and 0.0 hours per year LOLH for years 2016 and 2018. *The 2014 Probabilistic Assessment* Base Case results for 2018 were the same for the 2016 Base Case results. Also, the ProbA forecast planning reserve margin for the 2018 study year was 3 percent lower in 2014 compared to 2016.

- **Probabilistic vs. Deterministic Reserve Margin Results:** DR values reported in this report were modelled as generating resources available during daily on peak hours instead of reducing the total internal demand. Tier 1 wind resources with wind interconnection agreements that have not obtained firm transmission service were not included in the probabilistic assessment.

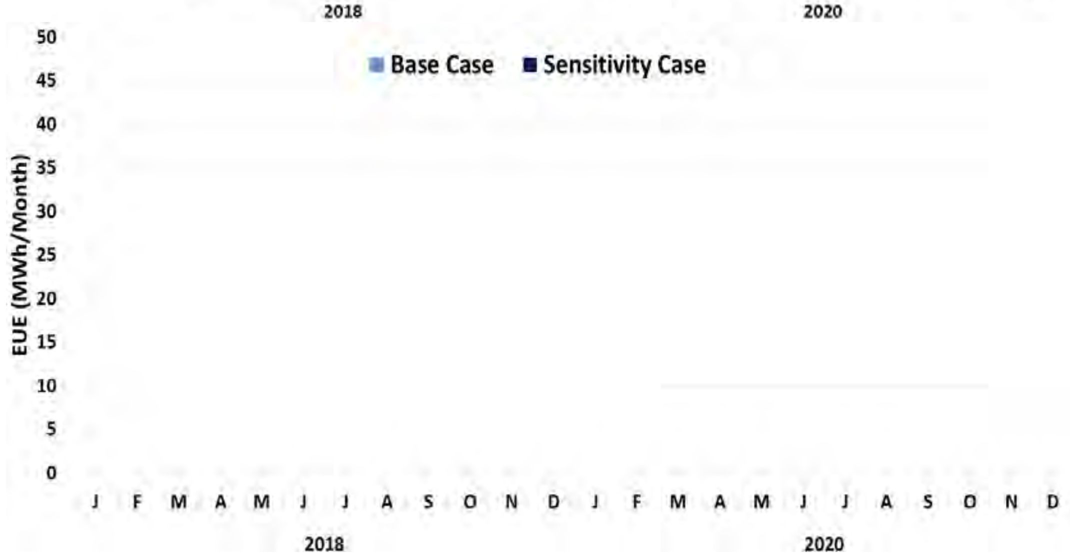
Base Case Study

No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20 percent in both study years and no major impacts were observed related to resource retirements.

Sensitivity Case Study

No loss of load events were indicated for the Sensitivity Case study due to a surplus of capacity in the SPP assessment area.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	25.1	22.7	22.6	18.0
Prospective	26.8	24.7	--	--
Reference	12.0	12.0	--	--
ProbA Forecast Planning	24.5	22.2	22.0	17.4
ProbA Forecast Operable	17.2	15.0	14.9	10.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.0	0.0	0.0	0.0
EUE (ppm)	0.0	0.0	0.0	0.0
LOLH (hours/year)	0.0	0.0	0.0	0.0



Summary

The SPP assessment area is forecasted to meet the 12 percent target reserve margin through the year 2026.

The SPP assessment area's energy efficiency and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability from energy efficiency and DR across the assessment area. The SPP assessment area forecasts the noncoincident summer peak growth at an average annual rate of one percent.

The SPP assessment area studies different scenarios in short-term and long-term planning to address the impacts of renewable portfolio standards, the integration of variable resources, and the changes in resource mix. Early in 2016, the SPP assessment area saw nearly 50 percent of SPP's load being served by wind generation at certain points, setting numerous wind penetration records. SPP has been able to reliably accommodate this kind of growth so far due to its ability to anticipate it in planning efforts. SPP continues to plan transmission to meet renewable portfolio standards within the SPP assessment area.

Since the previous LTRA, the SPP assessment area has not changed how on-peak capacity values for wind, solar, and hydro are calculated. The expected on-peak capacity values for variable generation are determined by guidelines established in SPP Planning Criteria section 7.1.5.3(g).[115]

The SPP assessment area's 2016 Board of Directors approved *SPP Transmission Expansion Plan* (STEP) provides details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. The *2016 STEP*[116] contains a comprehensive listing of all transmission projects in the SPP for the 20-year planning horizon, which consist of $6.1 billion in new transmission and upgrades.

The SPP assessment area is currently not anticipating unique emerging reliability issues over the assessment time frame. However, as renewable resources continue to expand, SPP will eventually be unable to reliably utilize this generation to address internal demand needs even with additional transmission infrastructure. This will increase the need for future renewables to be delivered to other regions. SPP will continue to monitor the uncertainty of potential policy changes concerning plant retirements over the assessment period.

Historically, similar to other regions, SPP has not been successful in regard to large-scale interregional transmission development. Developing the grid needed to reliably and cost-effectively accommodate expected future resource mixes will require Regions to more effectively work together to jointly plan and share costs of interregional transmission expansion.

[115] SPP Planning Criteria; January 2016
[116] 2016 SPP Transmission Expansion Plan Report; January 2016

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas, and it operates as a single BA. ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines and 566 generation units, and serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

Summary of Methods and Assumptions

Reference Margin Level
ERCOT-established Reference Margin of 13.75 percent

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

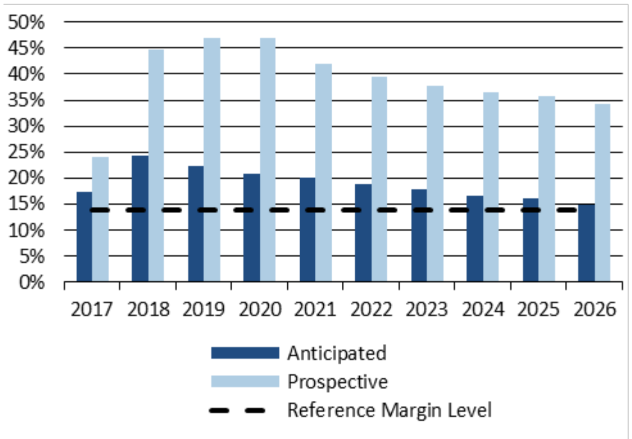
Planning Considerations for Wind Resources
Peak Capacity Contribution of 55 percent for Coastal units and 12 percent for Noncoastal

Planning Considerations for Solar Resources
ERCOT incorporates 80 percent capacity contribution

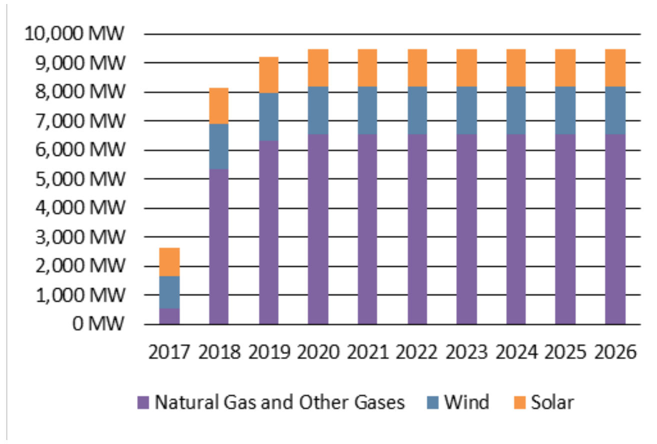
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	71,416	72,277	73,663	74,288	74,966	75,660	76,350	77,036	77,732	78,572
Demand Response	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868
Net Internal Demand	68,548	69,409	70,795	71,420	72,098	72,792	73,482	74,168	74,864	75,704
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	80,510	86,313	86,532	86,251	86,522	86,582	86,582	86,572	86,972	86,972
Prospective	85,050	100,361	104,007	104,930	102,281	102,106	101,739	101,729	102,129	102,129
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	17.45%	24.35%	22.23%	20.77%	20.01%	18.94%	17.83%	16.72%	16.17%	14.88%
Prospective	24.07%	44.59%	46.91%	46.92%	41.86%	40.27%	38.45%	37.16%	36.42%	34.91%
Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the ERCOT Region have increased since the 2014 probabilistic assessment to over 24 percent for 2018 and 20 percent in 2020, resulting in lower and insignificant levels of LOLH and EUE.

- **Modeling:** The 50/50 load forecast used for the study is based on 13 load shapes representing weather years for 2002-2014. ERCOT applied five load forecast uncertainty multipliers (ranging from -4 percent to +4 percent) to capture load forecast uncertainty in the sequential Monte Carlo simulation model. This year's study incorporated all new hourly values for the load, wind, and hydro shapes as well as updated generator outage data. Additionally, the probabilistic model topology was simplified from six to two zones. This was done to be consistent with the ERCOT Region along with an external zone, reflecting the historical peak-period availability of capacity across five dc ties connected to SPP and Mexico. This simplification was prompted by the 2014 study results that demonstrated that internal constraints between zones had an immaterial impact on the reliability metric results. ERCOT modeled DR resources with dispatch price thresholds, call priority rankings, and availability constraints (hours-per-season and hours-per-year).

- **Results Trending:** Compared to the 2018 results for the *2014 PRA Assessment*, LOLH decreased from 0.338 to 0.000004 while EUE decreased from 285.59 MWh to 0.005 MWh. These reductions are due to an increase in the Anticipated Reserve Margin from 13.6 percent to 24.4 percent for the 2018 forecast year. This reserve margin increase is attributable to both a lower peak load forecast as well as an increase in anticipated resources relative to those included in the *2014 LTRA*.

- **Probabilistic vs. Deterministic Reserve Margin Results:** No changes.

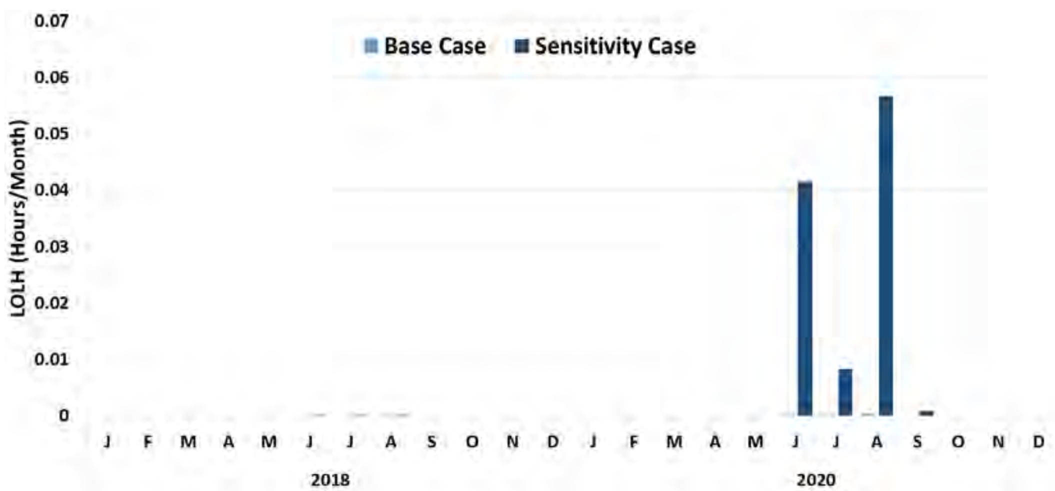
Base Case Study

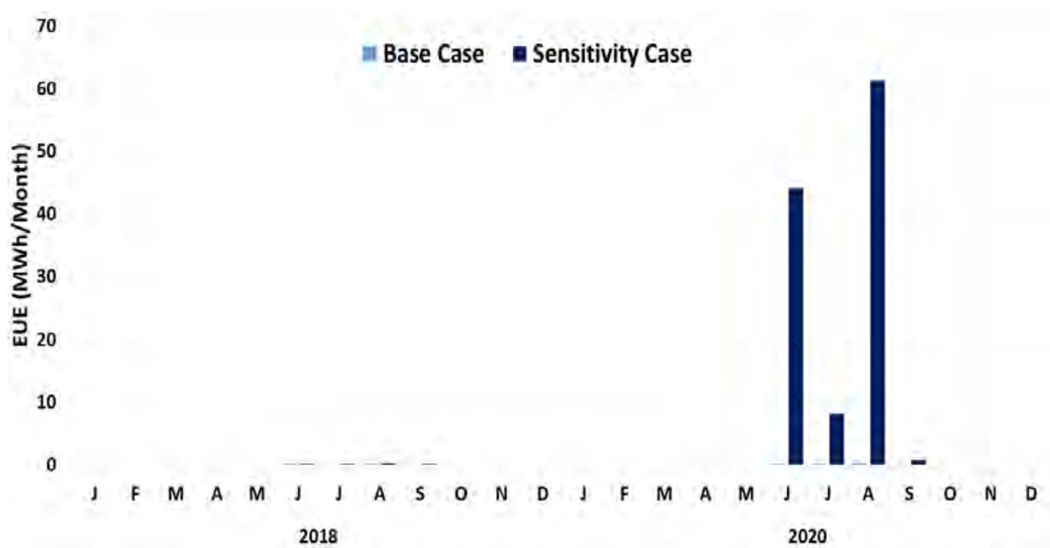
For the Base Case study, EUE and LOLH values were insignificant due to Planning Reserve Margins exceeding 20 percent for both forecast years. Loss of load occurred only during the summer season, with the majority in August. For example, in 2018, 78 percent of the EUE occurred in August. Relatively high values in June are driven by the 2012 weather year used to produce the load forecast. The second highest annual peak load from 2002 through 2014 occurred in June 2012.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	24.35	20.77	21.82	15.94
Prospective	44.59	46.92	41.64	41.05
Reference	13.75	13.75	13.75	13.75
ProbA Forecast Planning	24.35	20.77	21.82	15.94
ProbA Forecast Operable	14.83	11.42	12.49	6.97
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.005	0.395	0.243	114.19
EUE (ppm)	0.000	0.001	0.001	0.292
LOLH (hours/year)	0.000	0.001	0.000	0.107

Sensitivity Case Study

The results show that, as the reserve margin falls below 20 percent, the EUE remains low but begins to increase exponentially. This remains well above the target reserve margin used for the 2016 LTRA.





Summary

The Anticipated Reserve Margin is expected to remain above the Reference Margin Level (13.75 percent) for the duration of the assessment period. This is an improvement relative to the *2015 LTRA*, which indicated that planning reserves would drop below the Reference Margin Level beginning in 2022. This improvement is due to a relative increase of 2,800 MW in Tier 1 capacity additions starting in 2018, which increases to over 3,800 MW for 2020 and beyond. Note that project developers typically submit interconnection requests to ERCOT no more than three to four years before the facility is expected to enter commercial operations. As a result, the Texas RE-ERCOT Region will always show a flat level of capacity additions and typically declining reserve margins starting four to five years into the LTRA forecast period.

ERCOT's peak load forecast, updated in the fall of 2015, indicates system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.1 percent from 2016 to 2026. Historically, summer peak demand has grown at an AAGR of 1.3 percent from 2006 to 2015. The 2016 summer peak forecast is 70,588 MW, and grows to 78,572 MW for 2026. This new peak load forecast is within about 1 percent of the one used for the *2015 LTRA*, and assumes higher growth in the near- and medium-terms, but lower growth in the out years (2023 and onward). These changes in peak load growth are due to updated economic assumptions as well as an out-of-model adjustment that adds 655 MW of load to ERCOT's coastal zone to account for the expected 2019 completion of the Freeport Liquefied Natural Gas plant.

ERCOT continues to rely on a variety of DR programs administered by both ERCOT and several transmission and distribution service providers (TDSPs) to support resource adequacy under emergency conditions. For Summer 2017, ERCOT estimates that it will have about 1,153 MW of load resources providing ancillary services that are contractually committed to ERCOT during summer peak hours. ERCOT also has emergency response service, a 10- and 30-minute DR and distributed generation service, designed to be deployed in the late stages of a grid emergency prior to shedding involuntary firm load. For the Summer 2016 peak hours, there are 859 MW of emergency response service contracted from 1:00 to 4:00 p.m. and 824 MW from 4:00 to 7:00 p.m. This is a six percent decrease over the same time period for Summer 2015. The most significant factor contributing to the change in participation from previous years was the U.S. Environmental Protection Agency's rule changes; these rule changes pertain to reciprocating internal combustion engines and their ability to participate in emergency DR programs. Additionally, this assessment accounts for individual TDSP contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to attract approximately 208 MW of additional DR capacity, and are subject to concurrent deployment with existing ERCOT DR programs, pursuant to agreements between ERCOT and the TDSPs. In aggregate, these DR programs represent 3.5 percent of the Texas RE-ERCOT Region's total internal demand forecast.

Regarding new generation resources, the Texas RE-ERCOT Region saw almost 700 MW of summer-rated capacity added since the *2015 LTRA*. The resource additions were dominated by wind (425 MW) and natural gas (216 MW), followed by utility-scale solar photovoltaic (72 MW). Notable new installed plants include the gas-fired Ector Country Energy Center (294 MW summer rating) and the OCI Alamo 5 solar project (95 MW nameplate, 76 MW summer rating). Additionally, there were 24 wind facilities that entered commercial service with a nameplate capacity of 3,072 MW. Notable new Tier 1 plant additions include the Colorado Bend gas combined-cycle facility (1,148 MW summer rating), Halyard Wharton Energy Center (gas peaking, 419 MW summer rating), Pinecrest G gas combined-cycle facility (785 MW summer rating), Indeck Wharton Energy Center (gas peaking, 654 MW summer rating), and Red Gate internal combustion plant (225 MW summer rating). The most significant cancelled Tier 1 project is Pondera King, an 882-MW combined-cycle plant planned for the Houston area.

ERCOT does not expect that any of the six currently mothballed units will return to active status. ERCOT recently entered into a two-year Reliability Must Run (RMR) contract with an announced mothballed unit called Greens Bayou Unit 5. This 374 MW gas-steam unit is located in the Houston area, and was determined by ERCOT to be needed during the summer months for transmission reliability. This contract currently extends to June 30, 2018, subject to ERCOT Board of Director approval.

With respect to transmission projects, the recently updated projects list includes the additions or upgrades of 3,954 miles of 138-kV and 345-kV transmission circuits, 24,159 MVA of 345/138-kV autotransformer capacity, and 3,005 MVAR of reactive capability projects that are planned in the Texas RE-ERCOT Region between 2016 and 2024. A new Houston Import Project, 130-mile 345 kV double circuit line (each circuit rated at 5000 Amps) from Limestone to Gibbons Creek to Zenith, is planned to be in service before the summer peak of 2018. The Houston area demand is met by generation located within the area and by importing power via high-voltage lines into the area from the rest of the ERCOT system. This new line will support anticipated long-term load growth in the Houston region. Power imports into the Houston area are expected to be constrained until the new import line is constructed.

In July 2014, the owners of the Frontera generation plant, a 524 MW natural gas facility located on the west side of the Lower Rio Grande Valley (LRGV), announced that they were planning to switch part of the facility (170 MW) out of the ERCOT market in 2015, and the entire facility would no longer be available to ERCOT starting in the fall of 2016. In June, 2016, the ERCOT Board of Directors endorsed the reliability need for two 300 MVAr SVCs located inside the LRGV to be in service prior to Summer 2021 to meet ERCOT and NERC reliability criteria for the LRGV. ERCOT also completed under-voltage assessment and observed potential under-voltage load shedding and slow voltage recovery at 2021 summer peak load conditions in the LRGV area. Transmission upgrades were identified for this region to support the voltage recovery and meet the NERC and ERCOT planning criteria by year 2021. The upgrades include two 300 MVAR Static VAR Compensators (SVCs) in the LGRV area. In June 2016, the ERCOT Board of Directors endorsed the reliability need for these two 300 MVAr SVCs.

The Texas Panhandle region is currently experiencing significantly more interest from wind generation developers than what was initially planned for the area. The ERCOT Panhandle grid is remote from synchronous generators and requires long distance power transfer to the load centers in the Texas RE-ERCOT Region. All wind generation projects in the Panhandle are expected to be equipped with advanced power electronic devices that will further weaken the system due to limited short-circuit current contributions. Stability challenges and weak system strength are expected to be significant constraints for Panhandle export. The ERCOT Transmission Planning Department has been performing ongoing analysis to assess reliability when incorporating all wind generation in the Panhandle that satisfy the requirements of ERCOT’s transmission planning process. The stability and system strength are evaluated to ensure that reliable operations can be maintained through proper implementation of Panhandle export limits.

In terms of long-term resource adequacy and reliability risks, the retirement of multiple coal-fired generating units during the assessment period due to federal environmental regulations and market economics remains the greatest known risk. A number of coal units in the Texas RE-ERCOT Region are at risk for retirement due to requirements to upgrade existing flue gas desulfurization (FGD) equipment or install new equipment under the EPA’s Texas Federal Implementation Plan (FIP) for regional haze. Under the Texas FIP, 12 coal-fired units in ERCOT (totaling about 8,500 MW) will require FGD investments either by February 2019 (for units requiring upgrades) or February 2021 (for units requiring new equipment). In June 2016, the U.S. Court of Appeals for the 5th Circuit placed a judicial stay on implementation of the EPA's rule, thereby likely postponing the need for the unit owners to invest in new scrubbers or scrubber upgrades. As a result, there is large uncertainty regarding if and when coal units are retired. Nevertheless, ERCOT’s transmission reliability study, conducted in the fall of 2015 to analyze the impacts of multiple coal unit retirement scenarios, indicated that local or regional transmission impacts (transmission and transformer overloads) would be expected for all scenarios. To address transmission issues caused by specific retiring units, ERCOT and its stakeholders would pursue necessary transmission infrastructure upgrades or other alternatives (such as installation of voltage control devices or interruptible load procurement) through ERCOT’s transmission planning and project review process.

WECC

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BPS reliability in the Western Interconnection. WECC's 329 members, which include 38 BAs, represent a wide spectrum of organizations with an interest in the BPS. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is geographically the largest and most diverse of the NERC regional reliability organizations.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the BC, AB, and NWPP-US areas. These subregional divisions are used for this study as they are structured around Reserve Sharing groups that have similar annual demand patterns and similar operating practices.

Summary of Methods and Assumptions

Reference Margin Level
Determined by WECC's building block method for each subregion.

Load Forecast Method
Coincident for each subregion; normal weather (50/50)

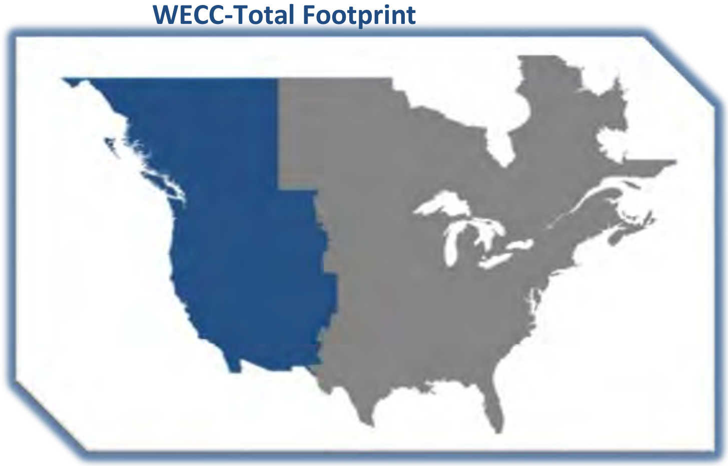
Peak Season
Summer: CA/MX, RMRG, SRSG, and NWPP-US
Winter: AB and BC

Planning Considerations for Wind Resources
Modeling, primarily based on up to five years of historic data

Planning Considerations for Solar Resources
Modeling, primarily based on up to five years of historic data

Footprint Changes
N/A

WECC-Total Footprint



WECC-AB Assessment Area Footprint

WECC-BC Assessment Area Footprint

WECC-CA/MX Assessment Area Footprint

WECC-NWPP-US Assessment Area Footprint

WECC-RMRG Assessment Area Footprint

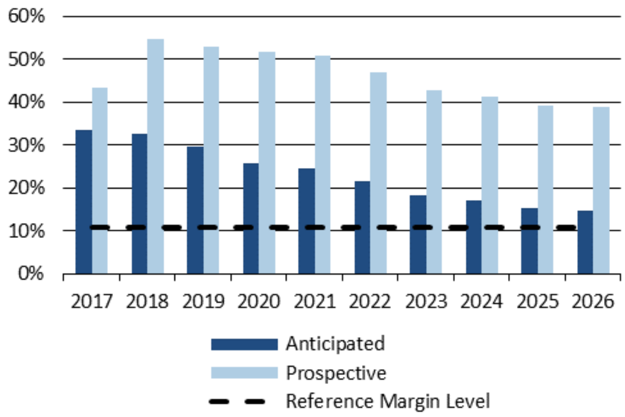
WECC-SRSG Assessment Area Footprint

WECC-AB

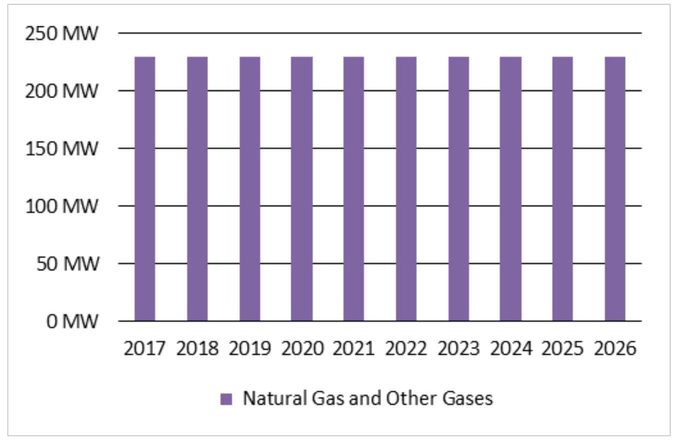
Peak Season Demand, Resources, Reserve Margins, and Shortfall [117]										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	-	-	-	12,942	13,198	13,460	13,705	13,910	14,114	14,304
Demand Response	-	-	-	0	0	0	0	0	0	0
Net Internal Demand	-	-	-	12,942	13,198	13,460	13,705	13,910	14,114	14,304
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	16,287	16,439	16,366	16,235	16,282	16,287	16,424
Prospective	-	-	-	19,648	19,902	19,788	19,565	19,643	19,648	19,878
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	33.56%	32.80%	29.62%	25.84%	24.56%	21.59%	18.46%	17.05%	15.39%	14.82%
Prospective	43.44%	54.86%	53.04%	51.81%	50.80%	47.01%	42.76%	41.22%	39.21%	38.97%
Reference Margin Level	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

[117] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-AB is a winter-peaking system that covers the province of Alberta Canada. For the probabilistic assessment, WECC utilized the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling**: Each Balancing Authority was modeled with import and export limits, consistent with the LTRA, based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's Generation Availability Data System (GADS). Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE; however, the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of near zero.
- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions whereas the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

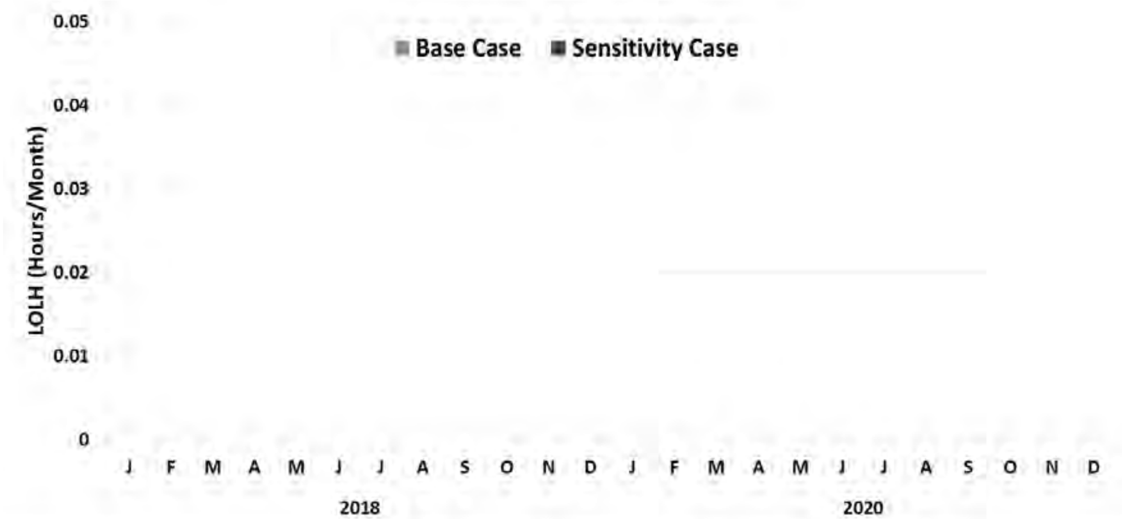
Base Case Study

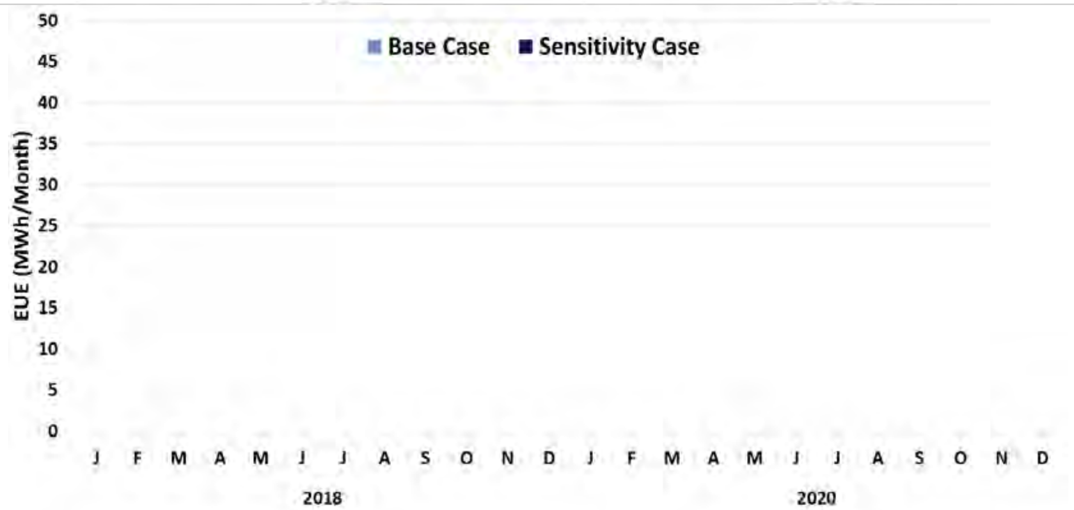
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 33 percent and 29 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
Anticipated	33.6	29.6	-	-
Prospective	43.4	53.0	-	-
Reference	11.0	11.0	-	-
ProbA Forecast Planning	33.6	29.6	30.9	24.6
ProbA Forecast Operable	30.7	26.8	28.1	21.9
Annual Probabilistic Indices				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



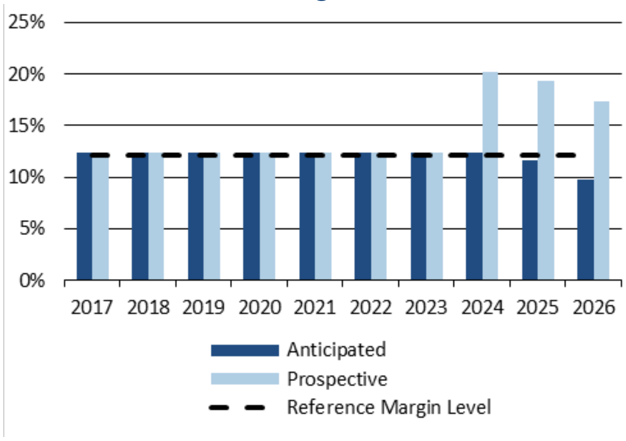


WECC-BC

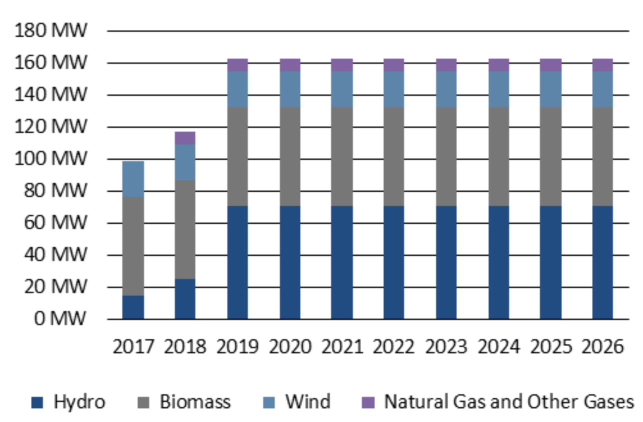
Peak Season Demand, Resources, Reserve Margins, and Shortfall [118]										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	-	-	-	12,140	12,242	12,401	12,524	12,690	12,853	13,040
Demand Response	-	-	-	0	0	0	0	0	0	0
Net Internal Demand	-	-	-	12,140	12,242	12,401	12,524	12,690	12,853	13,040
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	13,642	13,757	13,935	14,073	14,260	14,344	14,316
Prospective	-	-	-	13,642	13,757	13,935	14,073	15,250	15,334	15,306
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	12.39%	12.39%	12.38%	12.37%	12.38%	12.37%	12.37%	12.37%	11.60%	9.79%
Prospective	12.39%	12.39%	12.38%	12.37%	12.38%	12.37%	12.37%	20.17%	19.31%	17.38%
Reference Margin Level	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	64	302
Prospective	-	-	-	-	-	-	-	-	-	-

[118] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-BC is a winter-peaking system that covers the province of British Columbia Canada. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling**: Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as demand distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.
- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 23% and 20% for 2018 and 2020 respectively.

Sensitivity Case Study

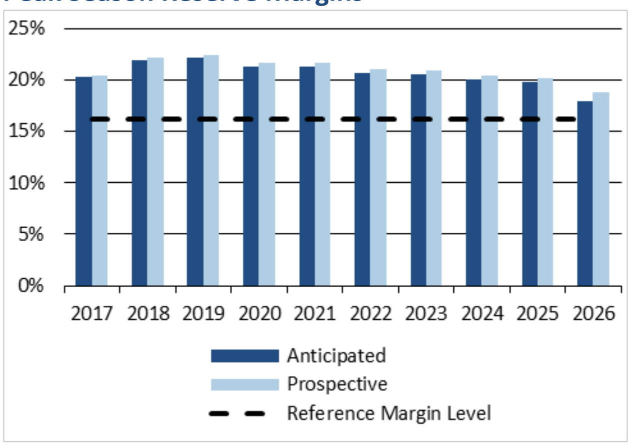
The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
Anticipated	12.4	12.4		
Prospective	12.4	12.4		
Reference	12.1	12.1		
ProbA Forecast Planning	23.5	20.0	21.1	15.4
ProbA Forecast Operable	20.7	17.3	18.4	12.8
Annual Probabilistic Indices				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

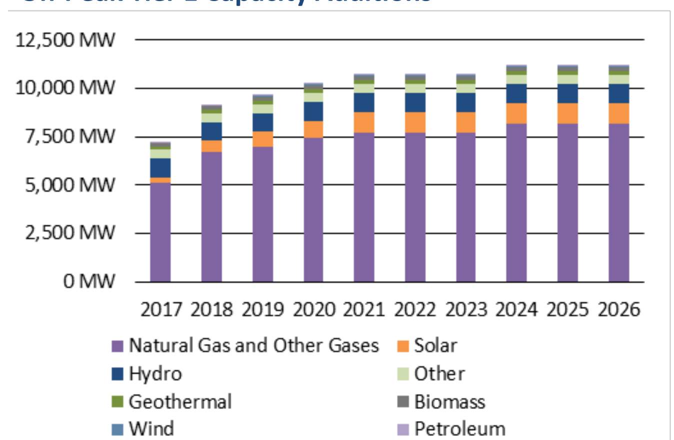
WECC-CA/MX

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	54,774	54,554	54,335	54,221	54,162	54,287	54,301	54,260	54,129	54,005
Demand Response	1,747	1,706	1,707	1,707	1,707	1,707	1,707	1,707	1,707	1,707
Net Internal Demand	53,027	52,848	52,628	52,514	52,455	52,580	52,594	52,553	52,422	52,298
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	63,765	64,428	64,261	63,711	63,626	63,441	63,364	63,068	62,796	61,639
Prospective	63,859	64,522	64,427	63,912	63,827	63,642	63,565	62,139	60,736	59,898
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.25%	21.91%	22.10%	21.32%	21.30%	20.66%	20.48%	20.01%	19.79%	17.86%
Prospective	20.43%	22.09%	22.42%	21.70%	21.68%	21.04%	20.86%	18.24%	15.86%	14.53%
Reference Margin Level	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	157	851

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-CAMX is a summer-peaking system that covers the state of California and portions of Baja Mexico. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

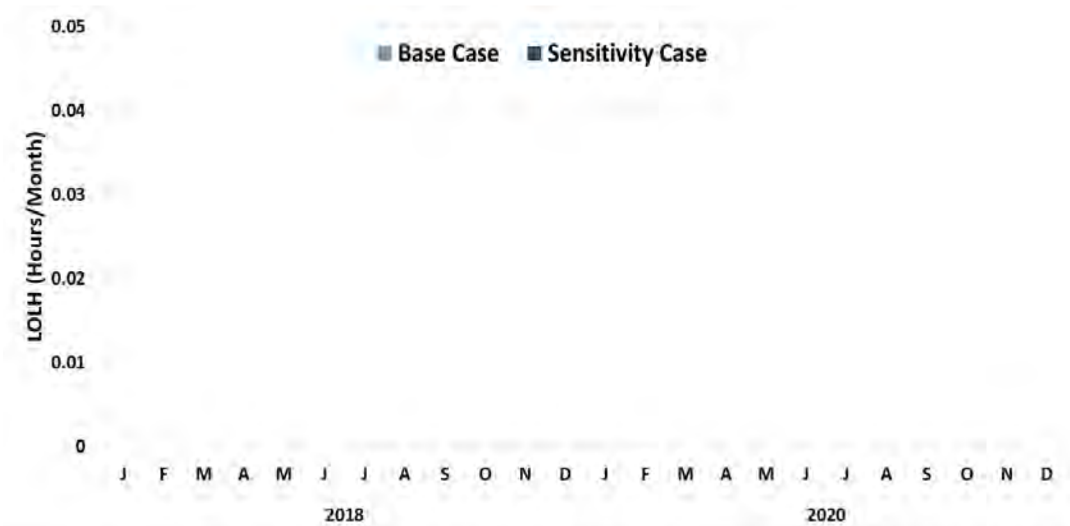
Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 32 percent and 36 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

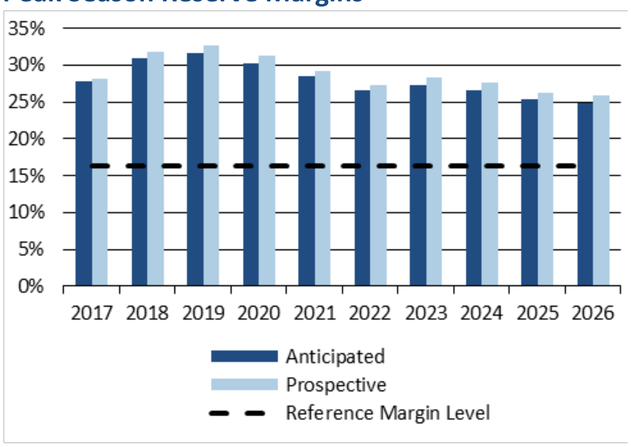
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	21.9	21.3	-	-
Prospective	22.1	21.7	-	-
Reference	16.2	16.2	-	-
ProbA Forecast Planning	32.4	36.1	29.7	30.7
ProbA Forecast Operable	21.9	25.4	19.4	20.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



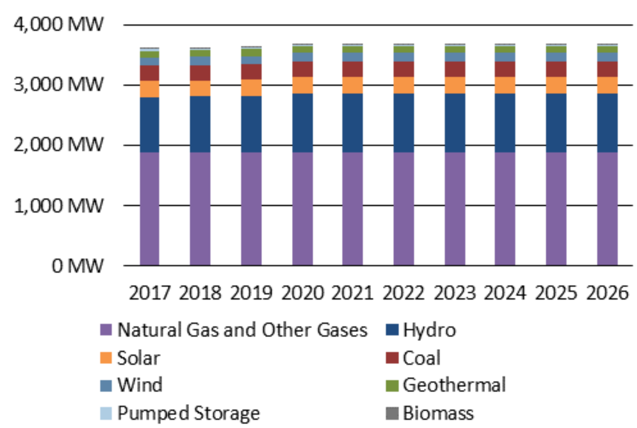
WECC-NWPP-US

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	50,013	50,438	50,851	51,319	51,693	52,119	52,479	52,869	53,439	53,294
Demand Response	1,219	1,186	1,196	1,195	1,195	1,193	1,213	1,189	1,187	1,193
Net Internal Demand	48,794	49,252	49,655	50,124	50,498	50,926	51,266	51,680	52,252	52,101
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	62,374	64,519	65,385	65,313	64,879	64,453	65,266	65,446	65,505	65,079
Prospective	62,568	64,913	65,927	65,811	65,288	64,819	65,792	65,987	66,003	65,562
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.83%	31.00%	31.68%	30.30%	28.48%	26.56%	27.31%	26.64%	25.36%	24.91%
Prospective	28.23%	31.80%	32.77%	31.30%	29.29%	27.28%	28.34%	27.68%	26.32%	25.84%
Reference Margin Level	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-NWUS is a summer-peaking system that covers a triangle of states from Washington to Montana and down through Nevada. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

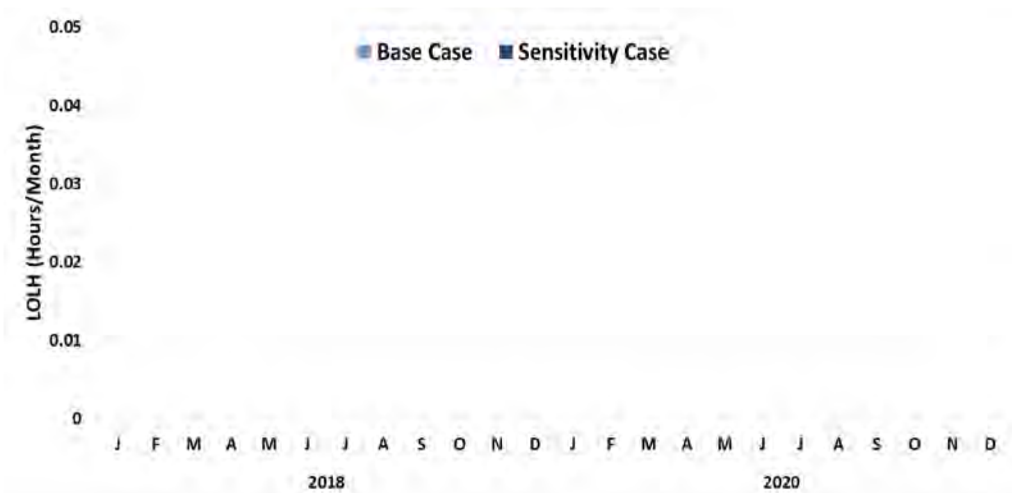
Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 41 percent and 37 percent for 2018 and 2020 respectively

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

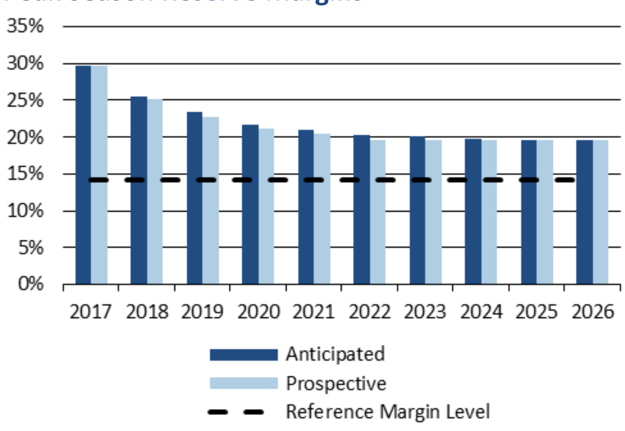
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	31.0	30.3	-	-
Prospective	31.8	31.3	-	-
Reference	16.3	16.3	-	-
ProbA Forecast Planning	41.7	37.9	38.9	32.5
ProbA Forecast Operable	30.3	28.1	27.7	23.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



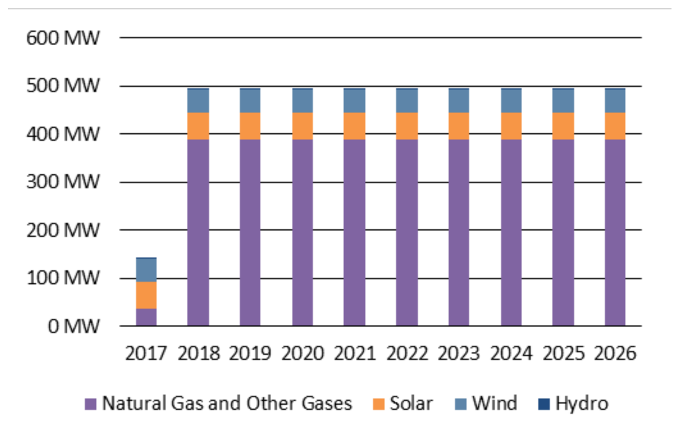
WECC-RMRG

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	12,392	12,530	12,759	12,947	13,194	13,375	13,552	13,739	13,910	14,094
Demand Response	545	562	581	603	609	615	620	626	631	635
Net Internal Demand	11,847	11,968	12,178	12,344	12,585	12,760	12,932	13,113	13,279	13,459
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	15,364	15,018	15,026	15,022	15,230	15,338	15,539	15,711	15,879	16,088
Prospective	15,364	14,975	14,945	14,951	15,159	15,270	15,472	15,685	15,879	16,088
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	29.68%	25.49%	23.39%	21.69%	21.02%	20.20%	20.16%	19.81%	19.58%	19.53%
Prospective	29.68%	25.13%	22.72%	21.12%	20.45%	19.67%	19.64%	19.61%	19.58%	19.53%
Reference Margin Level	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-RMRG is a summer peaking system that covers the states of Wyoming and Colorado. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

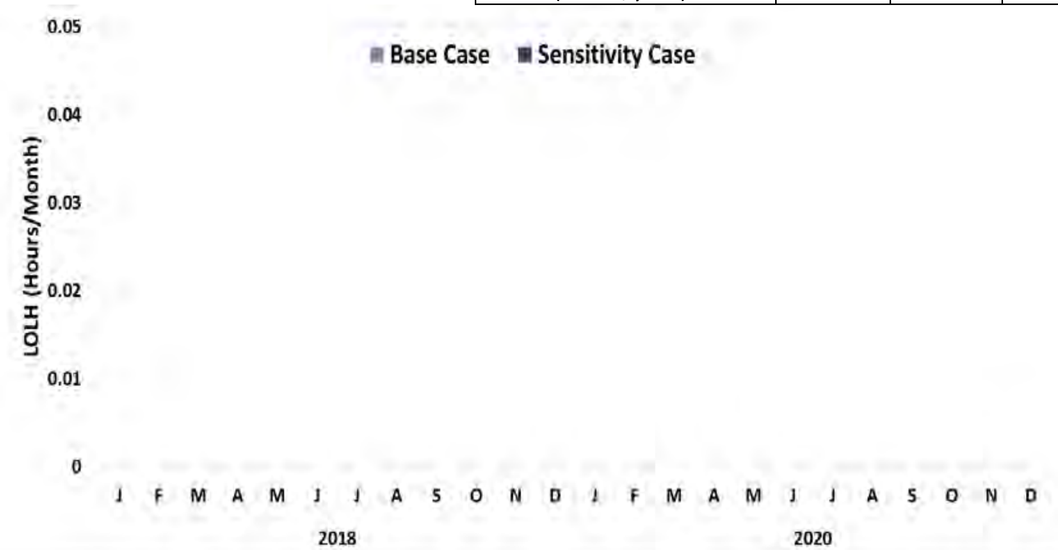
Base Case Study

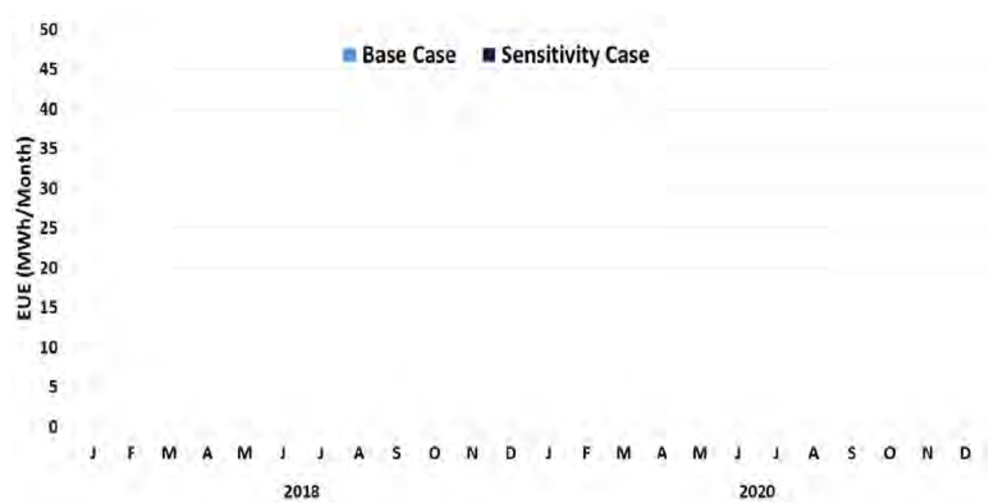
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 39 percent and 34 percent for 2018 and 2020.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	25.5	21.7	-	-
Prospective	25.1	21.1	-	-
Reference	14.1	14.1	-	-
ProbA Forecast Planning	39.1	34.9	36.3	29.5
ProbA Forecast Operable	28.4	24.6	25.8	19.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

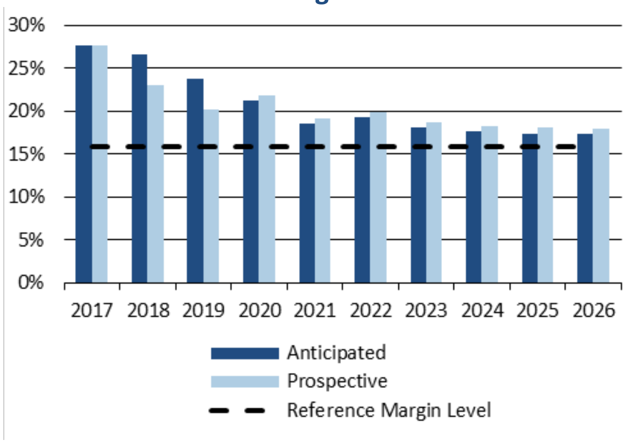




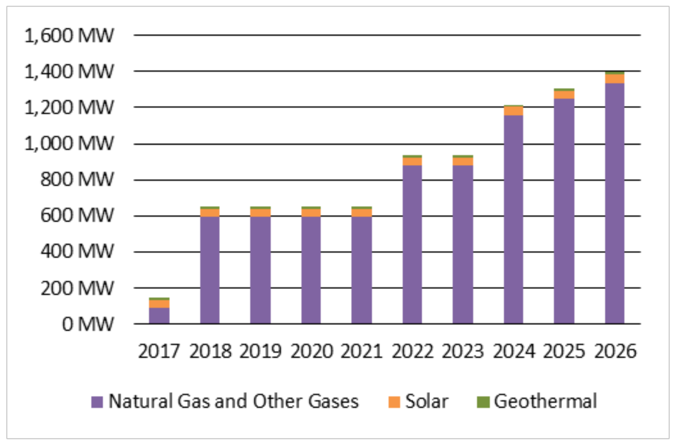
WECC-SRSG

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	23,207	23,534	24,023	24,479	24,978	25,319	25,766	26,211	26,871	27,424
Demand Response	420	359	363	355	355	355	355	355	355	355
Net Internal Demand	22,787	23,175	23,660	24,124	24,623	24,964	25,411	25,856	26,516	27,069
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	29,094	29,339	29,289	29,231	29,182	29,771	29,995	30,422	31,136	31,763
Prospective	29,095	28,504	28,454	29,395	29,346	29,936	30,160	30,586	31,300	31,927
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.68%	26.60%	23.79%	21.17%	18.52%	19.26%	18.04%	17.66%	17.42%	17.34%
Prospective	27.68%	22.99%	20.26%	21.85%	19.18%	19.92%	18.69%	18.29%	18.04%	17.95%
Reference Margin Level	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-SRSG is a summer peaking system that covers the states of New Mexico and Arizona and a portion of California. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.

- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.

- **Unit Modeling:** For base-load resources (nuclear, thermal, geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.

- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

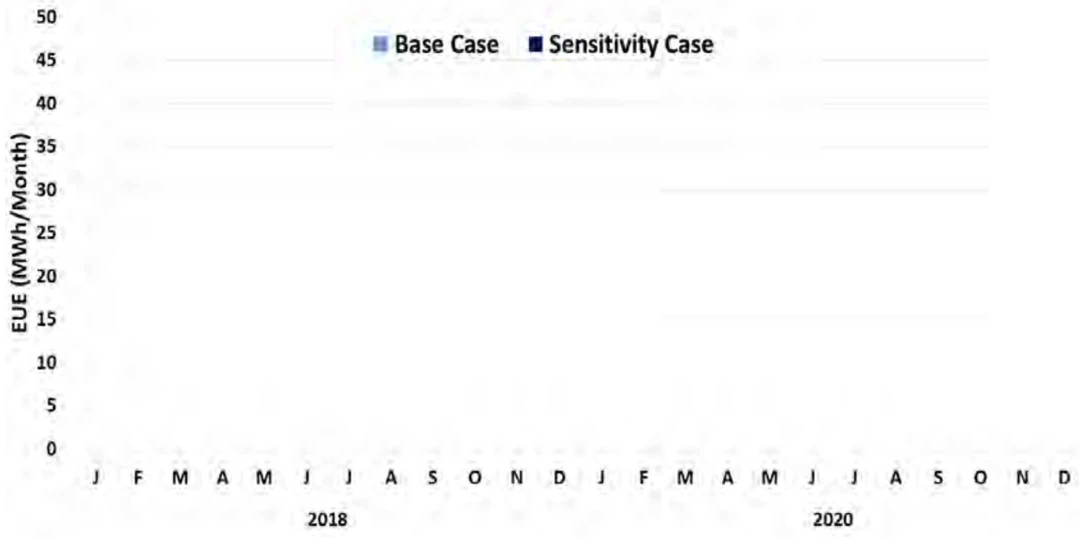
Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 40 percent and 34 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	26.6	21.2	-	-
Prospective	23.0	21.9	-	-
Reference	15.8	15.8	-	-
ProbA Forecast Planning	40.3	34.2	37.5	29.0
ProbA Forecast Operable	37.5	29.0	26.3	18.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



Planning Reserve Margins

Throughout the ten-year assessment period, the NERC Reference Margins range between 11 and 17 percent for the subregions. The NERC Reference Margin Levels have not changed significantly compared to those reported in last year's assessment. The NERC Reference Margin Levels are calculated using a WECC building block methodology[119] created by WECC's Reliability Assessment Work Group (RAWG), for its annual Power Supply Assessment (PSA).[120] The elements of the building block margin calculation are consistent from year to year but the calculations can, and do, have slight annual variances by region and subregion.

By the summer of 2026, the difference between WECC's prospective resources (196,392 MW) and WECC's net internal demand (162,578 MW) is anticipated to be 33,814 MW (20.80 percent margin). As the expected resources in excess of net internal demand significantly exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

The planning reserve margins for the WECC subregions remain above NERC Reference Margin Level throughout the assessment period. Beginning in 2025, one area within the NW-Canada subregion indicates a margin dropping 66 MW below its Reference Margin due to scheduled maintenance and WECC's conservative reporting of hydro energy. The nominal deficit is of no particular concern as there are ample (over 600 MW) prospective resources planned to be installed and operating by that period.

In the resource adequacy process, each BA is responsible for complying with the requirements of the state or provincial areas in which they operate. Some BAs perform resource adequacy studies as part of their Integrated Resource Plans, which usually provide a 20-year outlook. Other BAs perform resource adequacy studies that focus on the very short term (i.e., one to two years), but most projections provide at least a 10-year outlook. WECC's PSA uses a study period of 10 years and the same zonal reserve target margins throughout the entire period.

Similar to WECC's PSA, resources that are energy-only or energy-limited (e.g., the portion of wind resources that is not projected to provide generation at the time of peak) are not counted toward meeting resource adequacy in this assessment. Also, resources such as distributed or behind-the-meter generators that are not monitored by the BA's energy management systems are excluded from the resource adequacy calculation.

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119 Elements of the Building Block Target are detailed in the NERC: Long-Term Assessment – Methods and Assumptions report.
120 WECC's Power Supply Assessments.

Demand

Total internal demand for the summer, the peak season for the entire WECC Region, increased by 2.5 percent from 147,466 MW in 2014 to 150,830 MW in 2015, mostly due to high temperatures early in the summer season. Peak demand is forecast to increase at less than 1.0 percent per year from 2017 through 2026; this is lower than last year's 10-year compound load growth forecast of 1.1 percent. The annual energy load is projected to increase by less than 1.0 percent per year for the 2017–2026 time period, which is lower than the 1.2 percent projected last year for the 2016–2025 period.

Of interest is the negative demand growth forecasted for the CA/MX subregion due to anticipated increases in rooftop solar installations and a continued focus on energy conservation. Also of note is the more than 2,000 MW reduction in demand forecast for 2026 (2016 compared to 2015) in the NW-Canada subregion, associated with the expected decrease in oil extraction in the tar-sands region of Alberta.

Demand-Side Management

The WECC total internal demand forecast includes summer DR that varies from 4,102 MW in 2017 to 3,993 MW in 2026. The direct control DSM capability is located mostly in the California/Mexico subregion, totaling 1,772 MW in 2017 and decreasing to 1,731 MW in 2026. The most prevalent DR programs in WECC involve air-conditioner cycling as well as interruptible load programs that focus on the demand of large water pumping operations and large industrial operations (e.g., irrigation and mining). Currently, the most significant DR development activity within WECC is taking place in California; the California ISO (CAISO) is actively engaged with stakeholders in developing viable wholesale DR products with direct market participation capability. Also of note is CAISO's DR product implementation that facilitates the participation of existing retail demand programs in the CAISO market. Further information regarding these initiatives is available on CAISO's website.[121]

Overall DR program growth has been rather static and is expected to remain fairly constant over the 10-year planning horizon. The various DSM programs within WECC are treated as load modifiers that reduce total internal demand when calculating planning margins. In some situations, these programs may be activated by load-serving entities during high-power cost periods, but in general are only activated during periods in which local power supply issues arise. Generally, DR programs in WECC have limitations, such as having a limited number of times they can be activated.[122]

Generation

All of the balancing authorities within the Western Interconnection provided the generation data for this assessment, and WECC staff processed the data. The reported generation additions generally reflect extractions from generation queues.

DERs, including rooftop solar and behind-the-meter generation, currently represent a very small portion of existing resources. As the load served by these resources is not included in the actual or forecast peak demands and energy loads, these resources are excluded from the resource adequacy calculation. Unseen generation could begin to have impacts on the reliably operation of the interconnection as the amount of rooftop solar and other behind-the-meter generation increases. For example, rooftop solar installations in the CA/MX subregion are projected to grow substantially during the assessment period. It is projected that by 2026 there could be well over 11,000 MW of rooftop solar installed in that subregion alone, up from the current total of nearly 4,000 MW.

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[121] California ISO Demand Response Initiatives.

[122] NERC's assessment process assumes that demand response may be shared among load serving entities, balancing authorities, and subregions. However, DSM sharing is not a contractual arrangement. Consequently, reserve margins may be overstated as they do not reflect demand response that could potentially be unavailable to respond to external energy emergencies. Energy efficiency and conservation programs vary by location and are generally offered by the load serving entities. The reduction to demand associated with these programs is reflected in the load forecasts supplied by the balancing authorities.

A few utilities attributed planned and actual coal-fired plant retirements and fuel conversions to existing air emissions regulations. Based on news media accounts and information related to western coal-fired plant environmental regulation cost exposure, it is expected that future LTRA information will report additional retirements and fuel conversions as more plant owners establish their preferred approaches for addressing emission regulations. California regulations essentially specify that existing long-term contracts with coal-fired plants will be allowed to run to expiration though not renewed.[123] This regulation may result in the sale, retirement, or repowering of some power plants during the assessment period. Due to the somewhat fluid situation in California regarding retirements associated with once-through cooling (OTC) regulations, potential associated capacity reductions have not necessarily been reported for this year's LTRA for all potentially affected plants. Current information regarding the California OTC is available on the California Energy Commission's website.[124] It is expected that any future capacity reductions will be offset by new plants that may or may not be reflected in the current generation queue data.

The existing-certain and anticipated resources projected for the 2017 summer peak period total 202,567 MW and reflect the monthly shaping of variable generation and the seasonal ratings of conventional resources. The expected capacity modeling for wind and solar resources are based on curves created using at least five years of actual generation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capabilities are based on nominal plant ratings.

Greater wind and solar generation has resulted in an increased fluctuation in intermittent generation and a need for increased operating reserves to compensate for the wind-induced fluctuations. Improved wind forecasting procedures and reduced scheduling intervals have only partially addressed the wind variability issue. Increased wind generation has also exacerbated high generation issues in the Bonneville Power Administration (BPA) area during light load and high hydroelectric generation conditions; BPA provides current information regarding the issue on its website.[125]

A short-term concern that could affect generation in the Los Angeles basin in southern California is the outage of the Aliso Canyon natural gas storage facility. This facility helps to supply fuel to approximately 10,000 MW of generation in and around the Los Angeles basin. The Los Angeles Department of Water and Power, the California ISO, and SoCal Gas are developing short-term procedures to mitigate impacts to the power grid that could be caused by the Aliso Canyon outage. More information can be found in the Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin.[126]

Capacity Transfers

WECC does not rely on imports from outside the Region when calculating peak demand reliability margins. The Region also does not model exports to areas outside of WECC. However, imports may be scheduled across three back-to-back dc ties with SPP and five back-to-back dc ties with the MRO.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC.[127] The WECC resource allocation model places conservative transmission limits on paths between 19 load groupings (zones) when calculating the transfers between these areas. These load zones were developed for WECC's PSA studies. The aggregation of PSA load zones into WECC subregions may obscure differences in adequacy or deliverability between zones within the subregion.

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[123] CEC Emission Performance Standards.
[124] CEC Once-Through Cooling, and February 2016 Status.
[125] BPA Oversupply Management Protocol.
[126] CAISO: Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin
[127] WECC reports feasible transfers, not contracted transfers. This is done to eliminate double counting of resources. This treatment is different from the other NERC Assessment Areas.

The resource data for the individual subregions includes transfers between subregions that either are plant-contingent transfers or reflect projected transfers with a high probability of occurrence. Plant-contingent transfers represent both joint plant ownership and plant-specific transfers from one subregion to another. Projected transfers reflect the potential use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest as well as other economy and short-term purchases that may occur between subregions. Transfers that are supplied by existing and Tier 1 resources are classified as firm transfers while transfers from Tier 2 and Tier 3 resources are classified as expected transfers.

While these transactions may not be contracted, they reflect a reasonable modeling expectation given the history and extensive activity of the western markets as well as the otherwise underused transmission from the Northwest to the other subregions. When examining all Adjusted-Potential Resources, all subregions maintain adequate reserves (above respective targets) throughout the assessment period.

Transmission and System Enhancements

WECC is spread over a wide geographic area with significant distances between generation and load centers. In addition, the northern portion of the assessment area is winter-peaking while the southern portion of the assessment area is summer-peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full utilization of numerous transmission lines that does not adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify any adverse impact from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's Project Coordination and Path Rating Processes.[128] These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

The power transfer capabilities of most major subregion transmission interconnections within WECC are limited by system stability constraints rather than by thermal limitations. These stability constraints are sensitive to system conditions and may often be increased significantly at nominal cost by applying special protection systems (SPSs) or Remedial Action Schemes (RASs). In addition, transmission operators may install SPSs or RASs to address localized transmission overloads related to single- and multiple-contingency transmission outages. The future use of such relatively inexpensive schemes in lieu of costly transmission facility additions—whether they will be permanent or temporary additions—will depend on not yet determined system conditions.

Load-serving entities within WECC are rapidly expanding the use of smart meters and the associated interface equipment. The impacts of such facilities relative to power system reliability have not yet been quantified. Area entities are also taking steps to install and interface with equipment that may morph into full-fledged smart grid installations. The pace and extent of such changes is presently unknown. CAISO's website presents its smart grid initiatives; these are typical of activities within the assessment area.[129]

Long-Term Reliability Issues

WECC continues to track and study the impacts on reliability and other issues associated with the retirement of large thermal generating units in response to higher air emission and water quality standards. Associated with the retirement of large coal generating units is the increased demand on natural gas supply and transportation;

[128] WECC's Project Coordination, Path Rating, and Progress Report Processes.
[129] CAISO Smart Grid Roadmap

natural gas has become the primary fuel for new thermal generation. WECC is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

The CA/MX subregion is seeing a large increase in distributed resources. There is currently about 4,300 MW of rooftop solar installed in the Western Interconnection, with about 4,000 MW of that total installed in the CA/MX subregion. By 2026 that total is expected to increase to over 12,000 MW in the interconnection with over 11,000 MW installed in the CA/MX subregion. Although current operations indicate rooftop solar has not been a reliability issue, it is an issue that WECC and the CAISO are tracking was rooftop solar becomes a larger component of electric demand.

A joint NERC/CAISO study addresses some potential operational impacts from higher levels of variable resources (e.g., ancillary services for ramp rates). WECC studies to date have not identified significant issues relative to inertia and frequency response, but at some as yet unidentified penetration level, inertia and frequency response may become an issue. WECC continues to work with entities within the Interconnection to identify and study reliability concerns associated with the increasing levels of variable generation, including behind-the-meter rooftop solar facilities.

Retirement of Diablo Canyon Nuclear Generating Station

In June 2016, Pacific Gas and Electric (PG&E) announced plans to retire the 2,300 MW Diablo Canyon Nuclear facility, located in northern California. The first reactor is set to be retired by November of 2024, and the second reactor by August of 2025. PG&E indicates it will use the 9-year transition period to replace the generation with new greenhouse gas-free energy. The new energy supply options include energy efficiency, renewable power, and electric storage.

Western Reliability Summit

WECC, as the Regional Entity responsible for assuring the electric reliability in the Western Interconnection, hosted the first Western Reliability Summit. The two day summit, held on May 17–18, focused primarily on three reliability based topics: high reliability organizations, changing resources, and keeping pace with change. The summit was a unique opportunity to discuss thoughts and concerns about electric reliability challenges the Western Interconnection may face in coming years. WECC intends to hold similar summits that are focused on evolving reliability topics in the future.

Appendix I: Reliability Assessment Glossary

Term	Definition
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice (Source: NERC Glossary of Terms)
Anticipated Resources	Includes Existing-Certain Capacity, Net Firm Transfers (Imports – Exports), and Tier 1 Capacity Additions.
Anticipated Reserve Margin	Anticipated Resources minus Net Internal Demand, divided by Net Internal Demand, shown as a percentile.
Assessment Area	Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. (Source: NERC Glossary of Terms)
Bulk Electric System	See NERC Glossary of Terms
Bulk-Power System	A) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
Capacity Transfers (Transactions)	There are three types of capacity transfers (transactions): Firm: "Firm" transfers that require the execution of a contract that is in effect during the projected peak. The net of all Firm transfers (imports minus exports) are applied towards Anticipated Resources. Modeled: transfers that are applicable for assessment areas that model potential feasible transfers (imports/exports). While these transfers do not have Firm contracts, modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak season. The net of all Modeled transfers (imports minus exports) are applied towards Anticipated Resources. Expected: transfers without the execution of a Firm contract, but with a high expectation that a Firm contract will be executed in the future and will be in effect during the projected peak. The net of all Modeled transfers (imports minus exports) are applied towards prospective resources.
Conservation (Energy Conservation)	A reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, using occupancy sensors that turn off lights or appliances, and car-pooling. (Source: DOE-EIA)
Critical Peak-Pricing (CPP) with Load Control	Price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. Critical Peak Pricing (CPP) with Direct Load Control combines Direct Load Control with a pre-specified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices. Subset of Controllable and Dispatchable Demand Response.
	Dispatchable and Controllable Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.
Curtailment	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction. (Source: NERC Glossary of Terms)
Demand	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

	2. The rate at which energy is being used by the customer.
Demand Response	Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when required to maintain system reliability. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource. Controllable and Dispatchable Demand Response requires the System Operator to have physical command of the resources (Controllable) or be able to activate it based on instruction from a control center. Controllable and Dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; Direct Control Load Management (dcLM); Load as a Capacity Resource (LCR); and Interruptible Load (IL).
Demand-Side Management	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand. (Source: NERC Glossary of Terms)
Derate	The amount of capacity that is expected to be unavailable during the seasonal peak.
Designated Network Resource	Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program.
Distributed Energy Resources (DERs)	Distributed energy resources (DERs) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DERs such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. (Source: EPRI)
Distributed Generation	See *Distributed Energy Resources*
Energy Efficiency	Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVac) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. Results in permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions. (Source: DOE-EIA)
Estimated Diversity	The electric utility system's load is made up of many individual loads that make demands on the system, with peaks occurring at different times throughout the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.
Existing-Certain Capacity	Included in this category are existing generator units (expressed in MW), or portions of existing generator units, that are physically located within the assessment area that meet at least one of the following requirements when examining the projected peak for the summer and winter of each year: (1) unit must have a Firm capability (defined as the commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption (applies to generation and transmission), a Power Purchase Agreement (PPA), and Firm transmission; (2) unit must be classified as a Designated Network Resource; (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
Disturbance	An unplanned event that produces an abnormal system condition; any perturbation to the electric system, or the unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. (Source: NERC Glossary of Terms)
Existing-Other Capacity	Included in this category are existing generator units, or portions of existing generator units, that are physically located within the assessment area that do not qualify as Existing-Certain when examining the projected peak for the summer and winter of each year. Accordingly, these are the units, or portions of units, may not be available to serve peak demand for each season/year.

Energy-Only	Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area. Designated energy –only resources do not have capacity rights.
Expected Unserved Energy (EUE)	This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an assessment area (i.e., total of peak demand, Net Energy for Load, etc.). Normalizing the EUE provides a measure relative to the size of a given assessment area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.
Firm (Transmission Service)	The highest quality (priority) service offered to customers under a fixed rate schedule that anticipates no planned interruption. (Source: NERC Glossary of Terms)
Forced Outage	The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. Also, the condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)
Frequency Regulation	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control. (NERC Glossary of Terms)
Frequency Response	Equipment: The ability of a system or elements of the system to react or respond to a change in system frequency. System: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). (Source: NERC Glossary of Terms)
Expected (Provisional) Capacity Transfers	Future transfers that do not currently have a Firm contract, but there is a reasonable expectation that a Firm contract will be signed. These transfers are included in the Prospective Resources.
Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. (NERC Glossary of Terms)
Generator Owner	Entity that owns and maintains generating units. (NERC Glossary of Terms)
Independent Power Producer	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity. (NERC Glossary of Terms)
Interconnection	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Québec. (NERC Glossary of Terms)
Interruptible Load or Interruptible Demand	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (NERC Glossary of Terms)
Load	An end-use device or customer that receives power from the electric system. (NERC Glossary of Terms)
Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. (NERC Glossary of Terms)
Loss of Load Probability (LOLP)	This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.
Loss of Load Expectation (LOLE)	This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original classic metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day.
Loss of Load Hour (LOLH)	This is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE

	calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.
Net Energy for Load (NEL)	The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution. (Source: FERC-714)
	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities. (NERC Glossary of Terms)
Net Load	The difference between actual or forecasted load and actual or expected electricity production from variable generation resources.
Net Internal Demand	Total Internal Demand reduced by dispatchable and controllable Demand Response. (NERC Glossary of Terms)
Nonfirm Transmission Service	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption. (NERC Glossary of Terms)
Nonspinning Reserves	The portion of Operating Reserve consisting of (1) generating reserve not connected to the system but capable of serving demand within a specified time; or (2) interruptible load that can be removed from the system in a specified time.(NERC Glossary of Terms)
Off-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (NERC Glossary of Terms)
On-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. (NERC Glossary of Terms)
Open Access Same Time Information Service	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously. (NERC Glossary of Terms)
Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with nondiscriminating service comparable to that provided by Transmission Owners to themselves. (NERC Glossary of Terms)
Operating Reserves	The capability above Firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and nonspinning reserve.
Planning Coordinator (Planning Authority)	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. (NERC Glossary of Terms)
Planning Reserve Margins	Anticipated Reserve Margin: Anticipated Resources, less Net Internal Demand, divided by Net Internal Demand. Prospective Reserve Margin: prospective resources, less Net Internal Demand, divided by Net Internal Demand. Adjusted-Potential Reserve Margin: Adjusted-Potential Resources, less Net Internal Demand, divided by Net Internal Demand.
Peak Demand	The highest hourly integrated Net Energy For Load (or highest instantaneous demand) within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). (NERC Glossary of Terms)
Power Purchase Agreement	Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.
Prospective Capacity Resources	Anticipated resources plus existing-other capacity plus Tier 2 Capacity plus net Expected transfers.
Prospective Capacity Reserve Margin	Prospective capacity resources minus net internal demand shown divided by net internal demand, shown as a percentile.

Ramp Rate (Ramp)	Schedule: the rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. Generator: the rate, expressed in megawatts per minute, that a generator changes its output. (NERC Glossary of Terms)
Rating	The operational limits of a transmission system element under a set of specified conditions. (NERC Glossary of Terms)
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (Kvar) or megavars (MVar). (NERC Glossary of Terms)
Real Power	The portion of electricity that supplies energy to the load. (NERC Glossary of Terms)
Reference Margin Level	This metric is typically based on the load, generation, and transmission characteristics for each assessment area. In some cases, it is a requirement implemented by the respective state(s), provincial authority, ISO/RTO, or other regulatory body. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level may fluctuate for each season of the assessment period. If a Reference Margin Level is not provided by an assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. (NERC Glossary of Terms)
Renewable Energy (Renewables	Energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource. (Source: DOE-EIA)
Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group. (Source: NERC Glossary of Terms)
Stand-by Load under Contract	Demand which is normally served by behind-the-meter generation, which has a contract to provide power if the generator becomes unavailable.
Spinning Reserves	Unloaded generation that is synchronized and ready to serve additional demand.(NERC Glossary of Terms)
Time-of-Use (TOU)	Rate and/or price structures with different unit prices for use during different blocks of time. Time-Sensitive Pricing (Nondispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.
Total Internal Demand	Projected sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand should be reduced by indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all nondispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Adjustments for controllable Demand Response should not be included in this value.

	The demand of a metered system, which includes the Firm demand, plus any Controllable and Dispatchable DSM load and the load due to the energy losses incurred within the boundary of the metered system. (Source: NERC Glossary of Terms)
Transmission-Limited Resources	The amount of transmission-limited generation resources that have deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates takes precedence.
Uncertainty	The magnitude and timing of variable generation output is less predictable than for conventional generation.
Variable Energy Resources	Resources with output that are highly variable subject to weather fluctuations such as wind speed and cloud cover.
Variability	The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

Appendix II: Assessment Preparation, Design, and Data Concepts

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Assessment Data Questions
Direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2016 LTRA*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

NERC Reliability Assessment Staff

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NERC Reliability Assessment Subcommittee Members

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Tim Fryfogle	ReliabilityFirst	Matt Hart	Southern Company
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Assessment Preparation and Design

The *2016 Long-Term Reliability Assessment* (*2016 LTRA*) is based on resource adequacy[130] information collected from the eight Regional Entities (Regions) that is used to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks. The LTRA is developed annually by NERC in accordance with the ERO's Rules of Procedure,[131] as well as Title 18, § 39.11[132] of the Code of Federal Regulations,[133] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[134]

This assessment is based on data and information collected by NERC from the Regions on an assessment area basis as of September 2016. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the LTRA development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS in open meetings. The review process ensures the accuracy and completeness of the data and information provided by each Region. This assessment has been reviewed and accepted by the PC. The NERC Board of Trustees also reviewed and approved this report.

The *2016 LTRA* reference case does not reflect impacts that may result from the D.C. Circuit Court's mandate to vacate FERC Order No. 745,[135] nor the impacts that may arise from the EPA's CPP (Clean Air Act–Section 111(d)). While NERC provides a summary of the EPA's CPP, quantitative impacts from these developments will be considered for inclusion in future NERC assessments.

Data Concepts and Assumptions Guide

This section explains data concepts and important assumptions used throughout this assessment.

General Assumptions
The Reserve Margin calculation is an important industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak demand (load) and projected availability of resources to serve the forecast peak demand for the summer and winter of the 10-year outlook (2017–26).
All data in this assessment are based on existing federal, state, and provincial laws and regulations.
Demand Assumptions
Electricity demand projections, or load forecasts, are provided by each assessment area.
Load forecasts include peak hourly load,[136] or total internal demand, for the summer and winter of each year.[137]

130 Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency virtually all of the time. Resources are a combination of electricity-generating and transmission facilities that produce and deliver electricity, and demand response programs that reduce customer demand for electricity. Adequacy requires System Operators and planners to account for scheduled and reasonably expected unscheduled outages of equipment while maintaining a constant balance between supply and demand.

131 NERC Rules of Procedure - Section 803.

132 Section 39.11(b) of FERC's regulations provide: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

133 Title 18, § 39.11 of the Code of Federal Regulations.

134 BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that systems use to account for 80% of all electricity supply interruptions to end-use customers.

135 United States Court of Appeals for the District of Columbia Circuit - No.11-1486.

136 Glossary of Terms Used in NERC Reliability Standards.

137 The summer season represents June–September and the winter season represents December–February.

Total internal demand projections are based on normal weather (50/50 distribution)[138] and are provided on a coincident basis for most assessment areas.[139]

Total internal demand includes considerations for reduction in electricity use due to projected impacts of energy efficiency and conservation programs.

Net Internal Demand, used in all Reserve Margin calculations, is equal to total internal demand, reduced by the amount of Controllable and Dispatchable demand response (DR) projected to be available during the peak hour.

Resource Assumptions

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources:

- **Existing-certain generating capacity:** Includes operable capacity expected to be available to serve load during the peak hour with firm transmission.
- Tier 1 capacity additions: Includes capacity that has completed construction, is under construction, has a signed or approved ISA/PPA/CSA/WMPA, is included in an integrated resource plan, or is under a regulatory environment that mandates a resource adequacy requirement.
- **Firm Capacity Transfers (Imports minus Exports):** Transfers with firm contracts.

Prospective Resources: Includes all Anticipated Resources, plus:

- **Existing-other capacity:** Includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable for a number of reasons.
- **Tier 2 capacity additions:** Includes capacity that has been requested, but not received approval for planning requirements. Tier 2 capacity is counted toward the prospective resources category.
- **Expected (nonfirm) Capacity Transfers (Imports minus Exports): Transfers** without firm contracts, but a high probability of future implementation.

Reserve Margins

Reserve Margins:

The primary metric used to measure resource adequacy, defined as the difference in resources (anticipated, or prospective) and net internal demand, divided by net internal demand, shown as a percentile.

$$\textbf{Anticipated Reserve Margin} = \frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

$$\textbf{Prospective Reserve Margin} = \frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

Reference Margin Level: The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.

Fuel Types

[138] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[139] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

NERC collects and presents data on the generation mix based on the general fuel type identified for each unit. The fuel type is based on the prime movers and primary fuel type codes identified in the Form EIA-860 and provided below:[140]

- ***Coal***: Anthracite (ANT), Bituminous (BIT), Lignite (LIG), Subbituminous (SUB), Waste/Other (WC), Refined (RC)
- ***Petroleum***: Distillate Fuel Oil (DFO), Jet Fuel (JF), Kerosene (KER), Petroleum Coke (PC), Residual Fuel Oil (RFO), Waste/Other Oil (WO)
- ***Natural Gas***: Blast Furnace (BFG), Natural (NG), Other (OG), Propane (PG), Synthesis from Petroleum Coke Gas (SGP), Coal-Derived Synthesis Gas (SGC)
- ***Biomass***: Agricultural By-Products (AB) Municipal Solid Waste (MSW) Other Biomass Solids (OBS), Wood/Wood Waste Solids (WDS), Other Biomass Liquids (OBL), Sludge Waste (SLW), Black Liquor (BLQ), Wood Waste Liquids (WDL), Landfill Gas (LFG), Other Biomass Gas (OBG)
- ***Renewables***: Solar (SUN), Wind (WND), Geothermal (GEO), Hydroelectric (fuel type: WAT; primary mover: HY)
- ***Pumped Storage***: Pumped Storage (fuel type: WAT; primary mover: PS)
- ***Nuclear***: Nuclear (NUC)

[140] Additional information on fuel codes and prime movers are available in the Form EIA-860.

Table 9. 2016 net incremental electricity savings by state

State	2016 net incremental savings (MWh)	% of 2016 retail sales	Score (6 pts.)
Massachusetts	1,569,661	3.00%	7
Rhode Island	214,329	2.85%	7
Vermont	138,318	2.52%	7
Washington†	1,358,095	1.54%	5
California†	3,909,215	1.54%	5
Connecticut	442,250	1.53%	5
Arizona	1,108,273	1.42%	4.5
Maine†	157,921	1.38%	4.5
Hawaii*†	124,399	1.32%	4.5
Minnesota†	847,830	1.31%	4.5
Illinois	1,716,876	1.23%	4
Michigan	1,209,981	1.17%	4
Oregon†	537,331	1.16%	4
Idaho†	258,598	1.13%	3.5
New York	1,599,900	1.09%	3.5
Iowa†[1]	482,316	1.01%	3
Maryland	560,617	0.91%	3
Colorado	487,396	0.89%	3
Ohio	1,284,472	0.87%	2.5
Utah	232,299	0.78%	2.5
Pennsylvania	1,058,768	0.73%	2
Arkansas	310,815	0.68%	2
District of Columbia	73,811	0.65%	2
Nevada†	227,348	0.63%	2
Wisconsin	424,177	0.61%	2
New Mexico	135,000	0.59%	1.5
New Hampshire†	63,338	0.58%	1.5
North Carolina†	759,029	0.57%	1.5
Kentucky†	344,151	0.47%	1.5
New Jersey†	332,659	0.44%	1
Indiana†	424,127	0.42%	1
Oklahoma	236,027	0.39%	1
Missouri	301,909	0.39%	1
South Carolina*†	304,919	0.38%	1
Montana†	52,593	0.38%	1
South Dakota†	35,708	0.30%	0.5
Wyoming	47,057	0.28%	0.5
Georgia†	379,294	0.27%	0.5
Mississippi	126,027	0.26%	0.5
Tennessee†	189,930	0.19%	0.5
Nebraska†	56,275	0.19%	0.5
Texas[2]†	740,430	0.19%	0.5
West Virginia	57,925	0.18%	0.5
Florida†	263,116	0.11%	0
Louisiana†	87,023	0.10%	0
Virginia*†	99,557	0.09%	0
Alabama*†	49,988	0.06%	0
Delaware†	1,367	0.01%	0
North Dakota†[3]	1,761	0.01%	0
Alaska*†	346	0.01%	0
Kansas*†	440	0.00%	0
Guam	–	0.00%	0
Puerto Rico	–	0.00%	0
Virgin Islands	–	0.00%	0
US total	**25,417,008**	**0.68%**	
Median	**247,313**	**0.59%**	

Savings data are from public service commission staff as listed in Appendix A, unless noted otherwise. Sales data are from EIA Form 861M (2017b). * For these states, we did not have 2016 savings data, so we scored them on 2015 savings as reported in EIA Form 861 (2017a), unless otherwise noted. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.866 to make it comparable to net savings figures reported by other states. [1] 2016 savings reported for MidAmerican Energy and Interstate Power & Light; 2015 savings reported for municipal utilities and rural electric cooperatives. [2] Texas savings are from 2016, except for 2015 savings reported for CPS Energy and Energy Austin. [3] 2015 savings as reported in North Dakota data request.

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JUN 2, 2017 @ 01:59 PM 3,902

Why The U.S. Residential Solar Market Has Slowed Down

Great Speculations
Buys, holds, and hopes **FULL BIO**

Trefis Team, Contributor

Demand growth in the once-booming rooftop solar market in the United States appears to be leveling off, despite a reasonably healthy real estate market and strong consumer sentiment. During 2016, year-over-year installation growth slowed down to just 16%, compared to an average year-over-year growth of 63% over the three preceding years. Installations in the residential market could slow to as little as 9% this year. SunPower, the second largest U.S. solar player, which produces high-efficiency panels suited for rooftops, saw its Q1 2017 residential sales decline by 28% sequentially and by roughly 16% year-over-year. Below we take a look at some of the potential reasons for the slowdown in the residential solar market.

Regulatory Headwinds In Several States, Lower Electricity Prices

Utility companies have been pushing back against residential solar in multiple states, citing the higher effective costs of catering to customers with residential installations. In states such as Nevada, residential and small-scale commercial solar users face higher electricity rates, along with reductions in the credits they receive for sending their unused solar generated electricity back to the grid. California has also tweaked its regulations, with its "Net Metering 2.0" regulation, which brings about time-of-use rates which could effectively reduce the net value of solar power systems to homeowners. Under the TOU, solar electricity generated by customers in the afternoon – when supply from installations is abundant – is credited at lower rates than during the evening.

Average residential electricity rates in the U.S. have also softened on account of cheaper fossil fuels (particularly natural gas). In 2016, residential prices saw a slight decline, compared the average 2.2% annual increase over the previous decade. This has reduced the economic incentive for customers to go solar. Separately, community solar programs have also been gaining some traction, with the market expected to almost double this year. Under these schemes, homeowners pool their resources to build and share a larger community solar system, allowing people who cannot or prefer not to install solar panels on their rooftops to derive the benefits of solar power.

Why The Outlook May Still Be Bright

Solar panel prices have been declining rapidly, and the overall cost of systems is also coming down, due to higher panel efficiencies and lower balance of systems costs. Easy to install pre-engineered systems are also helping to bring down the time of installation and labor costs. Moreover, the dependence of residential solar customers on the grid and policies such as net metering could come down going forward, as behind-the-meter storage becomes more affordable and efficient with improving battery technology. For instance, GTM research estimated that storage in residential and non-residential solar installations stood at just 15% of installed capacity in megawatt terms. By 2021, however, the behind-the-meter segment will account for about half the U.S. market.

View Interactive Institutional Research (Powered by Trefis):

Global Large Cap | U.S. Mid & Small Cap | European Large & Mid Cap

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**))))))**	**DOCKET NO. UD-16-02**

REBUTTAL TESTIMONY

OF

CHARLES W. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

NOVEMBER 2017

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS?

A. My name is Charles W. Long. I am employed by Entergy Services, Inc. ("ESI") as Director, Transmission Planning. My business address is 6540 Watkins Drive, Jackson, Mississippi 39213.

Q2. ARE YOU THE SAME CHARLES W. LONG THAT FILED DIRECT AND SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY IN THE ABOVE CAPTIONED DOCKET?

A. Yes.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony supports the Supplemental and Amending Application in this proceeding, which seeks, among other things, approval to proceed with a project to construct New Orleans Power Station ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker"), totaling a summer capacity of approximately 128 MW. My Rebuttal Testimony addresses the arguments set forth in the Direct Testimony of Patrick W. Luckow, Robert M. Fagan, Elizabeth A. Stanton, and Peter J. Lanzalotta, filed on behalf of the Sierra Club, Alliance for Affordable Energy, 350 Louisiana-New Orleans, and Deep South Center for Environmental Justice. My Rebuttal Testimony also points out that I agree with many of the key points raised by Council Advisor witness Philip J. Movish, and I address the observations made by Mr. Movish concerning the magnitude of Demand-side Management ("DSM") levels contained in some of the transmission cases that contained the 2% DSM goal presented in my Supplemental and Amending Direct Testimony.

II. TESTIMONY

Q5. PLEASE PROVIDE AN OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A. My Rebuttal Testimony primarily responds to arguments raised in the Direct Testimonies of Patrick W. Luckow, Robert M. Fagan, Elizabeth A. Stanton, and Peter J. Lanzalotta (collectively the "Joint Intervenor Witnesses"). As a preliminary matter, it should be noted that none of the Joint Intervenor Witnesses have submitted any independent analysis to support their positions. Instead, they make unsupported contentions and speculations that, if accepted, would expose customers to a risky gamble from a reliability perspective.

Q6. PLEASE BRIEFLY SUMMARIZE THE MAIN OPINIONS EXPRESSED IN YOUR REBUTTAL TESTIMONY AND EXPLAIN YOUR QUALIFICATIONS FOR OFFERING SUCH OPINIONS.

A. First, unlike any of the Joint Intervenor Witnesses, I am a registered professional engineer in the state of Louisiana and I have over 25 years of experience in transmission system planning, operations and maintenance in the Amite South and Downstream of Gypsy ("DSG") Load Pockets, which are described more fully in my Direct Testimony at pages 3 and 4. It is also noteworthy that I have been involved in numerous hurricane restoration efforts in Southeast Louisiana, including the hurricane that has been discussed at length in this docket, Hurricane Gustav.

At the outset, it should be noted that all parties in this docket agree with the Company that the City of New Orleans currently faces reliability risks since the deactivation of the Michoud units in 2016, with one such risk involving the possibility of cascading outages in the New Orleans area if certain events were to occur on the transmission system. The parties disagree, however, over the best way to address these reliability concerns. For some time now, the Company has planned to construct a new generator because doing so would address the full suite of reliability concerns facing the New Orleans area, which the Company has an obligation to pursue for its customers. It should be noted that Council Advisor witness Philip Movish agrees that the construction of the RICE alternative is in the public interest and would address multiple reliability issues in New Orleans.

On the other hand, the Joint Intervenor Witnesses uniformly argue that instead of building local generation to replace a portion of that deactivated Michoud capacity to solve the reliability issues with a local resource in New Orleans, which would be intuitive to any reasonable transmission planner familiar with ENO's system, they argue that the Company should instead construct upgrades of five existing transmission lines. The Joint Intervenor Witnesses, however, ignore an important fact about their suggested approach—constructing transmission in the DSG area is extremely challenging and costly for multiple reasons and thus attempting to do so would expose the City to the risk of cascading outages beginning immediately and lasting until such a time when all upgrades are completed. I cannot stress enough that taking these transmission facilities out of service to upgrade them will be extraordinarily difficult and while each and every line is out for upgrade, the risk of cascading outages and/or the impact of an unplanned outage will increase dramatically.

Moreover, even assuming that the Company would be able to construct the upgrades at some point in the future given enough time and money, it is undisputed that ENO's customers would bear the current and persisting risk of cascading outages in the meantime; and even if constructed, these upgrades would not provide storm support or expedite storm restoration, would not afford any reliability margins in the transmission network to add new customers or to accommodate unexpected changes to the transmission system, would not significantly reduce line loading in the DSG area, would not contribute to any incremental dynamic reactive power in New Orleans, and would leave customers exposed to many of the operational reliability issues currently faced today. Simply put, the transmission upgrades are not an adequate solution to the suite of current reliability issues facing New Orleans based on my experience as a transmission planner.

The Joint Intervenor Witnesses also suggest that ENO can take the outages necessary to construct the transmission upgrades, or even solve the cascading outage issue, by implementing incremental behind-the-meter solar and/or DSM programs that will reduce peak demand over time. The Joint Intervenor Witnesses, however, do not offer any analysis regarding the feasibility or timing for these alleged solutions. As I have stated in my Supplemental and Amending Direct Testimony, future increased levels of behind-the-meter solar photovoltaic ("PV") and DSM are speculative and cannot reasonably be counted on to address a current and persisting reliability need. In other words, if the Joint Intervenors' suggested approach were to be adopted, these unquantified assumed savings that the Intervenors have speculated will result from additional behind-the-meter solar and DSM may never come to fruition, leaving ENO's customers exposed to the risk of cascading outages indefinitely. This risk is unacceptable; and I recommend that the Council take the responsible course of action by adding local generation to ENO's service territory at the Michoud site.

After reviewing the Direct Testimony of Robert Fagan, Elizabeth Stanton, and Peter Lanzalotta regarding transmission issues, I do not believe that they have presented any arguments or analyses that refute the fact that local generation is needed in the New Orleans area for reliability purposes and that transmission upgrades are not a suitable alternative.

In my Rebuttal Testimony, I also highlight the fact that Council Advisor witness Philip Movish and I agree on many points, including the risks inherent in following the Joint Intervenors' recommendations and the benefits of adding local generation in the City of New Orleans. I also respond to his observation that ENO used incorrect levels of DSM in certain cases within its reliability analysis that involved the Council's 2% goal. The Company has followed Mr. Movish's recommendation to rerun the cases that were affected by this error, and has concluded that the error had no material effect on any results contained in my Supplemental and Amending Direct Testimony. The Company reiterates, however, that the inclusion of the 2% DSM goal in reliability analyses is not appropriate because it could expose customers to serious reliability risks if the assumed reductions in peak load are not achieved.

Q7. DO THE JOINT INTERVENORS CONCEDE THAT ENO HAS A LONG-TERM RELIABILITY ISSUE THAT NEEDS TO BE ADDRESSED?

A. Yes. On page 5 of his Direct Testimony, Peter Lanzalotta admits that the deactivation of the Michoud resources resulted in the removal of 781 MW and that ENO is in an area that "depends on local generation to serve a portion of its load at various times under certain system conditions because of capacity limitations of the transmission lines connecting the load pocket with the rest of the system."[1] Additionally, although Mr. Lanzalotta argues (without any supporting analysis) that New Orleans' reliability

[1] *See* Direct Testimony of Peter Lanzalotta, at p. 5.

issues can be addressed by multiple different resources, he admits that "because of these generating unit retirements, this part of the Company's system requires additional resources to meet NERC-defined levels of reliability while serving its load as forecasted for the future."[2] In summary, Mr. Lanzalotta does not dispute that the Company and its customers face serious reliability risks, including the current and persisting risk of cascading outages through 2019 and beyond.

Q8. HAS MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO") ALSO CONFIRMED ENO'S RELIABILITY ISSUES AND THE POTENTIAL FOR CASCADING OUTAGES?

A. Yes. MISO's recent preliminary MTEP17[3] report identifies the critical category P6 contingency contained in my Supplemental and Amending Direct Testimony. The Appendix D3 of MISO's draft MTEP17 report also details the severe overload on the same limiting element observed in the Company's reliability assessment in support of NOPS and states that the severe overloads result in cascading outages.

Q9. IN YOUR OPINION, WHAT ACTIONS SHOULD THE COUNCIL TAKE TO ADDRESS THE RELIABILITY ISSUES FACING ENO'S SERVICE TERRITORY?

A. Based on my experience in planning and operating transmission in the New Orleans region, I believe that the construction of incremental dispatchable local generation is

[2] *See* Direct Testimony of Peter Lanzalotta, at p. 5.
[3] MISO Transmission Expansion Plan ("MTEP").

the only viable option to address the reliability problems facing the New Orleans area. First, it makes practical sense: 781 MW of local generation was deactivated, so a portion of that generation needs to be replaced locally. This approach not only addresses the current risk of cascading in the most expeditious manner, but the Company would also not need to schedule any crippling transmission outages to construct the unit, making it likely that the units will enter into commercial operation as expected. Moreover, the Joint Intervenor Witnesses do not seriously contest that either NOPS alternative would have reliability benefits that constructing more transmission (ENO is currently 100% reliant on transmission) simply will not bring – *i.e.,* NOPS will increase operational flexibility, decrease transmission line loading the most, create reliability headroom to add new customers, aid in storm restoration (including an option for black-start capability for one of the options), increase reactive power capability, add MWs to an area dependent on local generation but that contains an aging generator fleet, and run as a Voltage and Local Reliability ("VLR") unit in the DSG load pocket. Simply put, transmission upgrades will offer none of these benefits.

Q10. HAS MISO ALSO EXPRESSED A SIMILAR OPINION THAT GENERATION IS NEEDED IN ENO'S SERVICE TERRITORY FOR RELIABILITY PURPOSES?

A. Consistent with its role as a Regional Transmission Organization, MISO cannot require or mandate the construction of a generation resource. But, as a practical matter, MISO has identified reliability issues in New Orleans that its grid operators deal with on a daily basis. Also, as I have pointed out above, MISO has identified reliability constraints including the risk of cascading transmission outages in New Orleans in their latest draft MTEP17 report. It should be noted that MISO is an independent organization with no stake in the outcome of this matter. MISO works alongside area transmission owners to ensure reliable operations within its footprint, and the fact that MISO, in the exercise of its independent judgment, has identified a reliability issue in the New Orleans area should, along with the Intervenor witnesses' own admissions as noted above, underscore the seriousness and legitimacy of the reliability need at issue.

Moreover, at the September 13, 2017 New Orleans City Council Utility, Cable, Telecommunications and Technology Committee meeting, MISO, in its oral comments, detailed the ongoing operational challenges of operating the grid in the DSG load pocket, which has a high level of transmission imports. These comments emphasized the importance of having a good generation-and-transmission balance for operational flexibility and being able to respond to changes on the electric grid in the New Orleans area. MISO emphasized the importance of having local generation in the City of New Orleans and stated that Michoud is a good location for that generation.

Per its recent comments, MISO's system operators believe that local generation is needed to operate the grid in a manner that avoids unreasonable reliability risks and ensures that the grid is well equipped to deal with operational challenges and unforeseeable circumstances.

Q11. JOINT INTERVENOR WITNESSES MR. LANZALOTTA, MR. FAGAN, AND DR. STANTON PREFER TO CONSTRUCT TRANSMISSION UPGRADES IN LIEU OF LOCAL GENERATION. HOW DO YOU RESPOND?

A. It is clear that these witnesses do not fully understand the reliability implications of their recommendation. The transmission upgrades recommended by these witnesses are akin to placing a Band-Aid on a wound that needs serious medical attention. Over the course of the last 10 years, the City of New Orleans went from having three generating units within its borders to zero. The transmission topology in the area, however, which is a part of a load pocket called DSG (more fully described in my original Direct Testimony), has largely not changed. The DSG load pocket was designed to be supported by strategically placed generation in its center, and at its western and eastern edges. Following the retirement of the Michoud units, however, the leg supporting the eastern side of DSG has disappeared, meaning that at present, and figuratively speaking, all of the City's eggs are truly in one basket, as it is 100% dependent on transmission and remote generation resources.

To be clear, the Company has proposed the NOPS alternatives in order to address the underlying problem—the lack of any local dispatchable generation in New Orleans (the eastern side of DSG). In my opinion, constructing NOPS will restore the grid to how it was planned to be operated. Counsel Advisor Philip Movish agrees with this assessment, indicating in his Direct Testimony that "ENO's system is located at the extreme eastern end of the DSG load pocket" and that "considering ENO's transmission system topology, the proposed location of local generation at ENO's former Michoud site would be beneficial from a transmission reliability perspective…" In contrast, the Joint Intervenor Witnesses, none of whom have ever operated the electric grid in DSG or planned a single transmission project in a load pocket, advocate for upgrading five transmission lines in the electric network, which would exacerbate the City's dependency on transmission, incur additional reliability and economic risks, and would forgo the substantial additional benefits that only NOPS can provide.

What's more, these Joint Intervenor Witnesses ignore the challenges the Company would face if it were to attempt to construct these identified transmission upgrades. I have stated many times that the Company would face serious obstacles in attempting to construct transmission upgrades, including the inability to obtain necessary outages in the near-term because of the current real-world stressed operating conditions in DSG. As I have stated in my Supplemental and Amending Direct Testimony, since the retirement of the Michoud units, operating conditions in the DSG load pocket have been extremely difficult, with nine transmission outages being denied this year alone.

If the Company cannot receive the necessary outages to construct the upgrades, which is likely to be the case in the absence of a local resource that can provide counter-flow on the transmission network, the Company would need to build the upgrades along new transmission paths, adding significant costs and time to the projects at issue. Moreover, if the construction outage requests needed to develop these new transmission facilities were granted, which is not likely, ENO would be forced to operate at significantly higher risk of cascading outages during those construction outages, which should also be considered.

The Joint Intervenor Witnesses have not, and cannot, offer any analysis that supports the feasibility of constructing all the upgrades in an accelerated manner, and their dangerous recommendation will leave customers unnecessarily and unreasonably exposed to reliability risks for a longer period than is necessary. It is uncontested that either NOPS alternative can be constructed without lengthy outages and the Council can have a high degree of confidence that by deploying either NOPS alternative, the current threat of cascading outages will be mitigated as quickly as possible.

Furthermore, it is astonishing that even though the Joint Intervenor Witnesses all concede that ENO faces a **current** and **persisting** reliability challenge, they seem to have no sense of urgency with respect to mitigating these issues. Simply put, if the Company were to attempt to construct transmission upgrades in lieu of building NOPS, then customers will be exposed to serious reliability concerns for a much longer period than is necessary. None of the Joint Intervenor Witnesses, and none of the Intervenors themselves are load serving entities that have a responsibility to customers to serve load reliably. Simply put, ENO and the Joint Intervenors are not similarly situated when it comes to their expertise and responsibilities for maintaining reliability, and the Council should consider that discrepancy carefully in weighing the facts and opinions that have been offered in this proceeding.

Council Advisor witness Philip Movish agrees with the Company on this point, explicitly stating in his Direct Testimony that the "Transmission Alternative, either with or without the inclusion of the 2 percent DSM and solar photovoltaic PV capacity, presents significant reliability risks to New Orleans customers"[4] and that he would expect ENO to face "difficulties in taking its transmission lines out of service for the accomplishment of the needed upgrades…especially considering the duration of outages that would be required to replace transmission structures in support of re-conductoring, and the time required to accomplish re-conductoring work."[5]

Q12. HAVE THE INTERVENORS ACKNOWLEDGED THE CONSTRUCTABILITY ISSUES AND HAVE THEY SUGGESTED EFFECTIVE WAYS TO ADDRESS THESE CONCERNS?

A. The Joint Intervenor Witnesses recognize that constructability and outage scheduling will be a problem, but they suggest solutions that frankly have no basis in reality. When asked in his Direct Testimony about the Company's contention that "transmission line rights of way are scarce and transmission line construction conditions are difficult in and around ENO's service area," Mr. Lanzalotta conceded that "these are characteristics that could increase the cost of new or rebuilt transmission facilities," but went on to state that the Company should not rule out transmission as an alternative to new generation at NOPS prior to a more thorough analysis.[6]

While it is unclear what analysis Mr. Lanzalotta is suggesting the Company perform, it is clear that outage scheduling depends on real-world system conditions,

4 *See* Direct Testimony of Philip J. Movish, at p. 4.

5 *See* Direct Testimony of Philip J. Movish, at p. 27.

6 *See* Lanzalotta Direct Testimony, at 11-12.

which the Company cannot reasonably predict due to the many unknown variables involved. If the Company were to build new transmission paths, the Company agrees with Mr. Lanzalotta that this will indeed increase costs dramatically, but it will also take a significant amount of time and lead to substantial disruptions of the day-to-day activities in several communities as the Company attempts to acquire the servitudes and clear the rights of way necessary to construct the transmission lines and subsequently, engages in the construction work involving heavy machinery necessary to construct transmission structures. The Company would need to plan a path, determine which businesses, homes, churches, and other community resources would need to interrupted, then set about obtaining rights of ways, and the possible commencement of condemnation proceedings. If the Company is unable to secure the rights of ways for the new transmission lines for any number of reasons, it would need to select alternative paths and start the process of negotiating easements all over again.

For his part, Mr. Fagan suggests that the Company can gamble the reliability of the transmission system by adopting a strategy to reduce its load over time in order to help facilitate construction and scheduling of outages, stating that "ENO can effectively buy itself more time to ease any outage scheduling difficulties by taking steps to further reduce system peak demands."[7] Mr. Fagan offers no analysis to support his assertions, which I will discuss below, but more importantly, Mr. Fagan seems to overlook the fact that time is not a luxury that ENO, its customers, or the

[7] *See* Direct Testimony of Robert Fagan, at 35.

Council have, as there is a current and persisting risk for cascading outages that needs to be mitigated as quickly as possible.

Moreover, as stated above, Mr. Fagan has offered no analysis regarding the quantities, location, likelihood, and expected timing of the load reductions that would need to be implemented through a DSM program in order to reduce flows on the transmission system, thereby easing construction and outage difficulties. To be clear, ENO has performed a reliability sensitivity implementing the Council's 2% goal, and cascading outages still occur on ENO's system, which would indicate that DSM would not reduce loading on the system in a manner that will solve ENO's reliability needs, or ease concerns over the ability to take outages even if the goal is met.[8]

In addition, neither Mr. Fagan, nor any of the Joint Intervenors Witnesses, can guarantee that any projected amount of load reductions through incremental DSM or net load reductions realized through increased solar PV installations will actually be achieved. In fact, as Company witness Seth E. Cureington discusses in his Rebuttal Testimony, average monthly distributed solar interconnections in New Orleans have fallen by ~86% in 2017 compared to their peak in 2013. Through August 2017, ENO has averaged ~26 interconnections per month. This statistic indicates a declining rate of behind-the-meter solar installations at the same time Mr. Fagan would like the Company to depend on such installations to significantly reduce peak demands and "ease outage scheduling difficulties."

[8] *See* corrected transmission case 2% DSM-only, attached hereto as Exhibit CWL-8.

Thus, if Mr. Fagan's advice is followed, the Company could end up waiting to see if load reductions are achieved "over time" to facilitate outage scheduling, but no such load reductions may ultimately materialize, leaving ENO customers exposed to the reliability constraints, including the risks associated with cascading transmission outages for an indefinite period. In summary, these recommendations would not be a responsible course of action for ENO because it is tasked with ensuring a reliable electric grid for customers.

Additionally, even if these load reductions could be achieved and were enough to take the needed outages, which Mr. Fagan has not proven, the risks to load associated with taking transmission lines out for extended periods of time to perform the upgrades would dwarf the reliability margins on the transmission system gained by any such load reductions.

Mr. Fagan also discusses the "use of existing within-DSG generation…"[9] as a means of easing outage scheduling challenges, which is a suggestion that is particularly puzzling. Mr. Fagan seems to think that such resources are not being utilized currently for outage scheduling. In fact, MISO makes full use of any available resources, including dispatching such resources optimally, in order to allow the scheduling of outages to the extent that such existing resources within DSG can assist in the scheduling of the transmission outages. However, the existing DSG resources, which are located in the central and western portions of DSG, have a lesser impact on the critical transmission constraints in New Orleans that are located in the

[9] *See* Direct Testimony of Robert Fagan, at 35.

eastern portion of DSG. For these constraints, as mentioned earlier, no DSG units other than the proposed NOPS can effectively provide counter-flow to the transmission system in order to ease the loading on the network and help with the scheduling of outages, without increasing operational risks.

Finally, Mr. Fagan suggests "appropriate sequencing of any required outages"[10] as a means of enabling the scheduling of outages. Taking any outages, regardless of sequence, will be extraordinarily difficult and will expose the City to risk while the outage is occurring. Additionally, this is not a new concept, and MISO already uses all available transmission and generation elements, as well as sequencing, in order to schedule outages. This assertion, however, also supports the Company's position in this case, which is that it would have to sequence the necessary construction outages and therefore it could not work on all needed projects at one time. Thus, the time necessary to complete all five of these upgrades could extend significantly beyond the in-service date for either NOPS alternative because the Company would be required to complete single projects in a sequence instead of beginning them all at once.

[10] *See* Direct Testimony of Robert Fagan, at 35.

Q13. ON PAGE 37 OF HIS DIRECT TESTIMONY, MR. FAGAN ASSERTS THAT THERE ARE NINE TRANSMISSION REINFORCEMENT ACTIVITIES CURRENTLY UNDERWAY IN THE DSG AND AMITE SOUTH LOAD POCKETS. PLEASE RESPOND.

A. Not one of the transmission lines projects listed in Mr. Fagan's testimony would eliminate ENO's reliability issues, including the risk for cascading outages. The Company agrees that these projects are currently underway, but this fact only makes it all the more unreasonable to expect that the Company would be able to obtain five additional outages and undertake the other necessary steps to develop five additional transmission projects in a timely manner, as discussed above. Moreover, the referenced nine transmission projects were included in all of the Company's reliability analysis and any mitigating impact of these nine projects on the current and persistent reliability constraints in the absence of a local generator have already been taken into consideration in the reliability analyses that I have detailed in my Supplemental and Amending Direct Testimony.

Q14. YOU HAVE STATED THAT CONSTRUCTING TRANSMISSION WILL NOT PROVIDE OPERATIONAL FLEXIBILITY, EASE TRANSMISSION LINE-LOADING, CREATE OPPORTUNITIES TO GROW, OR PROVIDE STORM RESTORATION BENEFITS OR BLACK-START CAPABILITY. HAVE THE JOINT INTERVENORS ARTICULATED ANY SUBSTANTIVE REBUTTAL TO ANY OF THESE POINTS?

A. No. The Joint Intervenors, as discussed more fully below, are very narrowly focused on merely achieving North American Electric Reliability Corporation ("NERC") compliance. This is likely because none of them has ever planned or operated the electric grid and they do not realize that New Orleans has unique locational concerns that drive needs that the transmission upgrades, and mere NERC compliance for that matter, simply do not address.

As I discuss more fully below in response to each of the Joint Intervenors' contentions, increasing operational flexibility by easing the loading on the transmission grid in the area is an extremely important consideration, as this will then give grid operators the ability to respond to unexpected conditions, receive approvals to conduct maintenance outages, and will result in less load at risk alerts in the DSG area. Similarly, having the headroom to undertake necessary maintenance and add new customers without exposing the area to reliability risks is also important in an area like New Orleans, which is primed for growth. Conversely, failing to consider these important needs or undertaking a "band-aid" approach, as advocated by the Joint Intervenor Witnesses, risks creating an impediment or obstacle to such growth.

Regarding storm benefits, it should be obvious that having local generation in a storm prone area is imperative to assist restoration crews in returning service to customers as quickly as possible, which the Company is obligated to do. The Joint Intervenors Witnesses do not seriously contest these points.

On the other hand, the Council's Advisors acknowledge that these are significant benefits that constructing local generation can bring to New Orleans, but that constructing more transmission cannot, stating that the "RICE Alternative also would provide other significant benefits to New Orleans, including operational flexibility, dynamic system support for voltage regulation, on-site black start capacity to support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage. Further, the RICE Alternative, subject to further study, could potentially provide a source of power for the Sewerage & Water Board's ("S&WB") Carrolton facility in the event that generation was impaired or inoperable."[11]

Q15. IN RESPONSE TO ENO'S ARGUMENTS ABOUT THE BENEFITS OF OPERATIONAL FLEXIBILITY, MR. LANZALOTTA, ON PAGE 6 OF HIS DIRECT TESTIMONY, STATES THAT THE TRANSMISSION UPGRADES AT ISSUE "WOULD ALSO ADD TRANSMISSION CAPACITY AVAILABLE FOR THE SCHEDULING OF PLANNED MAINTENANCE ON THE TRANSMISSION SYSTEM." HOW DO YOU RESPOND?

A. Operational flexibility refers to the concept of affording the system operators the ability to respond to changes in the system. Such changes to the system may involve unplanned transmission and generation outages, weather events which result in outages or damage to the electric infrastructure, and requests for maintenance and construction outages. Operational flexibility is typically enhanced when the system is operated in a manner that ensures there is headroom or margin in both generation resources (*i.e.*, generators can respond by either raising or lowering their operating

[11] *See* Direct Testimony of Philip J. Movish, at pg. 4.

points) and on the transmission system (*i.e.*, the transmission system has the ability to accept incremental power flow without resulting in a reliability or economic constraint) such that the transmission grid is capable of reacting to an unforeseen event that changes the operating state of the transmission network.

While the five transmission upgrades listed in Table 1 of my Supplemental and Amending Direct Testimony, if constructed, may help reduce loading on those specific 5 transmission lines, the loading on the rest of the transmission system will remain substantially the same. Put differently, save for those five lines upgraded, the rest of the transmission system will remain largely stressed to the same degree as it is today. Therefore, if ENO were to construct the transmission upgrades, the transmission system can be expected to exhibit the same operational challenges as we see today (*i.e.*, outage scheduling denials, operational constraints such as load-at-risk-alerts, *etc*.). Furthermore, as stated above, it should also be noted that taking the outages necessary to perform the upgrades will dramatically increase reliability risk during each outage since the system will be in a weakened state during each and every planned outage.

Table 1 below lists the impact on the degree to which transmission branch flows reduce as a result of the following three scenarios: (a) the construction of the transmission upgrades listed in Table 1 of my Supplemental and Amending Direct Testimony, (b) the 128 MW RICE resources, and (c) the 226 MW CT. As can be expected, the CT produces the biggest reduction in flows on the transmission system; hence, the CT can be expected to increase operational flexibility and reduce stresses the most. Conversely, the transmission-only option produces the smallest magnitude of transmission line flow reductions, and therefore, is expected to result in a transmission grid with the least amount of operational flexibility.

Table 1

Number of Transmission Lines with Significant (more than 10%) Flow Reductions in 2022		
Transmission Only	128 MW RICE	226 MW CT
4	24	33

Additionally, the residual loading on transmission lines, tabulated below in Table 2, also show a similar trend. Reduction in residual loading is highest with the introduction of the 226 MW CT and lowest with the implementation of the transmission-only option.

Table 2

Reduction in Number of Transmission Lines Loaded Above 75% in 2022		
Transmission Only	128 MW RICE	226 MW CT
2	6	7 (no lines above 75% remain)

These two tables definitively demonstrate that the transmission-only option results in the lowest reduction in transmission system loading, and consequently, will result in the least amount (almost negligible) of flexibility in the system, contrary to Mr. Lanzarotta's assertion.

Q16. DOES THE ABILITY TO REDUCE LOADING ON THE SYSTEM ALSO GIVE ENO THE ABILITY TO ADD NEW CUSTOMERS?

A. Very likely so. As I have stated in my Direct Testimony, the presence of a local generator located at the Michoud site would create counter-flow and result in a system that is less dependent on transmission to meet customer demand, resulting in reduced loading on the transmission grid. From the perspective of customer growth, it is best to maintain a system with at least some headroom/reliability margins necessary to serve new load without being vulnerable to reliability issues. For example, the same Joint Intervenors that are opposing the construction of the NOPS alternatives are also likely to favor of the increased use of electric vehicles. While the Company does not necessarily endorse his statements, it should be noted that Tesla's CEO, Elon Musk, has predicted that electric demand will substantially increase by 200% as cars and heating transition to electricity as a source of fuel, which will increase dependency on traditional utility resources by a factor of two.[12]

In another more immediate example, the Company is in discussions with a potential customer that presently has over 50 MW of load that has not been included in ENO's load forecast. While this customer is a little more certain to interconnect because the load currently exists in the system but is currently served by self-generation, the Company also is in constant discussions with potential new developmental customers, none of whom will locate their businesses in New Orleans without assurances that reliable electric service will be available. The point here is this: it is best to have a system that can handle a change, like the addition of incremental electric demand, without putting customers at risk; and it is undisputed that the upgrades at issue in this proceeding will not create reliability margins on the transmission system sufficient to handle any new growth.

[12] *See* attached link: https://www.cnbc.com/2016/10/28/elon-musk-says-solar-power-doesnt-threaten-utilities.html.

Q17. JOINT INTERVENOR WITNESSES MESSRS. LANZALOTTA AND FAGAN DISCUSS HURRICANE RESPONSE, BUT NEITHER WITNESS STATES THAT HE HAS PARTICIPATED IN A HURRICANE RESPONSE EFFORT IN SOUTH LOUISIANA, OR ANYWHERE ELSE. CAN YOU PLEASE ELABORATE ON YOUR ROLES AND EXPERIENCE WITH ASSISTING THE ENTERGY OPERATING COMPANIES WITH HURRICANE RESPONSES?

A. I have been involved in a variety of roles during the restoration of various storms in the Company's history. I have played an active role in leading construction crews in storm-affected area to rebuild transmission infrastructure following storms. For instance, I was instrumental in re-constructing the transmission system in the New Orleans area following Hurricane Katrina, in addition to working in challenging conditions to restore transmission lines lost to wind damage and substations lost to flooding. I have also been involved in leading storm restoration planning efforts at the System Command Center in several storms, which has included the development of complex plans to restore multiple damaged facilities in a coordinated fashion while maximizing customers restored and minimizing system risk, prioritizing and developing restoration plans for critical facilities such as oil refineries, city services, medical facilities, *etc*. I also monitored the Gustav island situation from the System Command Center and directed the activities to re-synchronize the Gustav island to the remainder of the Eastern Interconnection.

Q18. MR. LANZALOTTA SEEMS TO SUGGEST, ON PAGES 7 AND 8 OF HIS DIRECT TESTIMONY, THAT GENERATION IS NOT NEEDED AFTER A STORM BECAUSE ELECTRIC LOADS CAN BE REDUCED DUE TO DISTRIBUTION AND TRANSMISSION DAMAGE. PLEASE RESPOND.

A. Local generation is very helpful in expediting restoration following a storm. It is true that total load is reduced after a storm. However, NOPS is not designed to carry the entire load in the area. In the absence of local generation, the power system is completely dependent on the transmission system to feed the distribution system, from which most of the residential and commercial loads are served. Thus, under a scenario with no local generation, damage to the transmission system would render restoration efforts fruitless until the transmission system is able to transport power from remote resources to the City's loads. On the other hand, a local resource would provide an alternative source of power to the distribution system over shorter distances of transmission. Therefore, a local resource will restore power following a storm faster and give a system operator the flexibility to restore loads quicker than if the City were 100% dependent on transmission. Depending solely on long distance transmission for restoration would be akin to relying upon the fire department in the City of Kenner to fight fires in New Orleans East, rather than having local fire stations to provide this timely and essential service. It is obvious that relying upon the Kenner Fire department will expose New Orleans East residents to significant risks considering the distance and traffic conditions at issue. Having local fire stations in New Orleans East would provide the fastest possible means of fighting fires in that area, just as a local generator would be the best tool to address storm recovery in the eastern part of DSG.

The other obvious benefit of local generation is that it can provide service to customers in the event that the City or the region is either completely islanded, or a significant portion of the transmission lines that import power are forced out of service during a storm. In my Direct Testimony, I explained that in Hurricane Gustav, fourteen transmission lines were forced out of service, disconnecting the region that included the City of New Orleans from the remainder of the U.S. electric grid. During that time, as discussed more fully below, the region was totally dependent on electric service generated within the island for any load that was served. In that situation, transmission could not have powered a single additional home, business, hospital, or pumping station inside the Gustav island.

Q19. MR. LANZALOTTA CLAIMS, ON PAGE 8 OF HIS DIRECT TESTIMONY, THAT WIDESPREAD OUTAGES WERE NOT SIGNIFICANTLY MITIGATED BY THE PRESENCE OF GENERATION FOLLOWING HURRICANE GUSTAV, STATING THAT 80% OF THE COMPANY'S CUSTOMERS WERE INTERRUPTED DURING THAT STORM. PLEASE RESPOND.

A. To begin, the Company has never claimed that local generation will prevent interruptions of electric service resulting from all storm damage. Damage to transmission and distribution infrastructure from debris, wind and lightning during storms cannot be avoided by a local generator. However, in an island situation, as is what occurred after Hurricane Gustav, the absence of local generation would have led to 100% loss of service to all customers from New Orleans to Baton Rouge. Thus, Mr. Lanzalotta's example actually further illustrates the Company's point, which is that without local generation, the 20%[13] of customers that were able to continue accept electric service (which could have included critical infrastructure such as hospitals, police stations, *etc*.) would have been in the dark.

Moreover, it should also be noted that after Hurricane Gustav, which will be discussed more fully below, the New Orleans area was dependent on local generation for quite some time after the island was reconnected to the larger electric grid, as only 6 of the 14 transmission lines were restored more than five days after the storm. Without local generation, including contributions from Michoud Units 2 and 3, customers would have been forced to wait on transmission repairs for the restoration of electric service.

Q20. ON PAGE 8 OF HIS DIRECT TESTIMONY, MR. LANZALOTTA ALSO CLAIMS THAT THERE ARE NO REPORTS THAT THE MICHOUD UNITS OPERATED DURING HURRICANE GUSTAV TO PROVIDE RELIABILITY. PLEASE RESPOND.

A. Hurricane Gustav, which made landfall on September 1, 2008 as a Category 2 hurricane, resulted in extensive damage to the transmission system of the Entergy Operating Companies.

[13] The Company notes that peak customer outages during Gustav was approximately 76%.

Prior to landfall, Michoud Units 2 and 3 were taken offline because of the risk of the storm surge that the area experienced after Hurricane Katrina. As noted above, 14 transmission lines serving the Baton Rouge and the metropolitan New Orleans areas were lost as the storm moved inland, forming an electrical island. The area between the metropolitan New Orleans area and a corridor along the Mississippi River between New Orleans and Baton Rouge were completely disconnected from the rest of the grid. Three generators, with a combined capacity of nearly 1,570 MW, were able to sustain and serve this electric island.

One day after the storm, September 2, 2008, a little over 60,000 customers were still without power, with over 58% of customers having their service restored or never having lost service. These customers were heavily dependent on local generation, with only 1 of the 14 lines being placed into service just before midnight of that day. On the second day after the storm, September 3, 2008, Michoud Unit 2, which had a long start-up time, was placed back into service when just 3 of the 14 lines had been restored to service. At that time, restoration efforts were clearly not complete and the City of New Orleans was heavily dependent on local generation, including Michoud Unit 2.

On September 5, 2008, four days after the storm made landfall, Michoud Unit 3 was also placed into service and all electric loads that could accept service were restored without any transmission or generation supply constraints. Five days after the landfall, September 6, 2008, almost all of ENO's customers had been restored, though only 6 of the 14 transmission lines had been restored. This demonstrates the crucial role that local generation, including Michoud Units 2 and 3, played in the restoration of electric load in the greater New Orleans area during Hurricane Gustav. Further, it also illustrates the importance of having local generation within New Orleans for future restoration efforts.

Q21. IN HURRICANE GUSTAV, NEW ORLEANS WAS FORTUNATE IN THAT IT WAS ABLE TO RECEIVE POWER FROM OTHER UNITS IN THE AREA. COULD A SITUATION ARISE THAT WOULD DISCONNECT THE CITY FROM ALL OTHER GENERATING UNITS?

A. Yes. If transmission lines to the east (and electric downstream direction) of the Ninemile generating station in Westwego, LA were to be rendered out of service and if the transmission line that connects the Michoud substation to Slidell, LA were also inoperative, the City of New Orleans will be disconnected from all generating resources in the MISO transmission grid. In this situation, given the lack of generation in the New Orleans area, all electric loads would be lost. This scenario actually involves the outages of fewer transmission lines than the 14 implicated in the Gustav island.

Q22. PLEASE RESPOND TO MR. LANZALOTTA'S POINT, ON PAGE 8 OF HIS TESTIMONY, THAT THE MICHOUD SITE WAS DAMAGED DURING HURRICANE KATRINA AND THAT, THEREFORE, THE COMPANY SHOULD NOT BUILD THE PLANT AT THAT LOCATION.

A. The Company had some concerns following the Hurricane Katrina storm surge, but Mr. Lanzalotta fails to recognize the various concrete steps that the United States

Army Corp of Engineers has taken to reduce the risk of flooding due to storm surge in the New Orleans East area. The Supplemental Testimony of Company witness Jonathan E. Long, on pages 16-22, details these efforts, which include constructing the world's largest flood barrier, closing the Mississippi River Gulf Outlet, and improving the flood protection system in New Orleans East.

These efforts, coupled with the fact that these improvements were tested by Hurricane Isaac, and the fact that the elevation of the proposed unit is 3.5 ft. higher than sea level (2.5 ft. higher than FEMA's recommended elevation), creates a much lower risk profile for operating a unit located at the Michoud site during a storm. As is also discussed by Mr. Jonathan E. Long, this much lower risk profile was also concurred with by the group of insurance companies that evaluated the site when deciding whether they would provide insurance to a new unit at the Michoud location.

Q23. ON PAGES 9-10 OF HIS DIRECT TESTIMONY, MR. LANZALOTTA SUGGESTS THAT ENO COULD UNDERGROUND ITS TRANSMISSION SYSTEM IN LIEU OF BUILDING LOCAL GENERATION TO RECEIVE STORM HARDENING BENEFITS. PLEASE RESPOND.

A. Mr. Lanzalotta fails to recognize that if his strategy were to be implemented, then any transmission line that is not buried underground quickly becomes the weakest link in the electric grid and the most vulnerable element of the electric grid that is susceptible to storm damage. This means that even if every single line in the Company's transmission grid were to be buried underground (even though the costs would be astronomical), all transmission lines that lie upstream of the City of New Orleans would still be overhead and would remain vulnerable to storm damage. To substantially improve risk profiles in the geographically unique area, many hundreds of miles of transmission lines (much of which ENO does not own) would need to be buried. Accordingly, even putting aside the costs of implementing Mr. Lanzarotta's proposed strategy of undergrounding the City's transmission lines, which would prohibitive, the City would remain vulnerable to storm damage because of all the transmission lines that feed the City from other jurisdictions would remain overhead.

Q24. ON PAGE 10 OF HIS TESTIMONY, MR. LANZALOTTA SUGGESTS THAT THE CITY OF NEW ORLEANS DOES NOT NEED BLACKSTART CAPABILITY, AND THAT IT SHOULD SIMPLY REINFORCE TRANSMISSION LINES DESIGNED TO IMPORT POWER IN A BLACKSTART SITUATION.

A. Mr. Lanzalotta does not dispute that additional black-start capability with the City would provide benefits. As explained in the response to Q22. of my Supplemental and Amending Direct testimony, the Company currently relies upon a transmission cranking route originating at the Waterford substation for the provision of black-start capability to New Orleans. Presently, a majority of this cranking path lies outside of the Company's electric grid. Thus, the transmission reinforcements recommended by Mr. Lanzalotta are far upstream of New Orleans, outside of ENO's control.

Again, ENO can harden its system, but it would still be dependent on lines that are beyond its control for reliability. In short, having the ability to self-start a unit rather than relying on long stretches of transmission lines to provide that ability can have significant benefits and reinforcing transmission lines outside of ENO's service territory cannot replace such benefits. It should also be noted that Mr. Movish agrees that having blackstart capability in New Orleans can be a significant benefit, "considering that ENO's identified cranking path for Waterford Nuclear to Michoud is approximately forty miles long."[14]

Q25. DR. STANTON, AT PAGE 25 OF HER TESTIMONY, ARGUES THAT THE SOUTHERN CROSS PROJECT WILL ALLOW ENO TO ENTER INTO INEXPENSIVE PURCHASED POWER AGREEMENTS FOR WIND RESOURCES. CAN YOU PLEASE RESPOND?

A. The Southern Cross Transmission Project ("SCTP"), as is currently contemplated, involves a High Voltage Direct Current ("HVDC") line from the Louisiana – Texas border to the Mississippi – Alabama border. This means that the inexpensive energy referenced by Dr. Stanton will be available at the terminal of the HVDC line at the Mississippi – Alabama border, not anywhere in proximity to the City of New Orleans. Not only is this HVDC terminal not in the MISO market, but this terminal, as currently shown on the SCTP website, is at least 250 miles away from the nearest ENO substation.

Not only will a Purchased Power Agreement ("PPA") with SCTP involve transmission service, including possible external Network Resource Integration Service from far outside the MISO footprint into the MISO market, but it would likely require costly transmission upgrades in the Southern Company, Cooperative

[14] *See* Direct Testimony of Philip J. Movish, at pg. 38.

Energy, or TVA transmission systems to be able to facilitate such a PPA on a firm basis. Moreover, once the power from the terminal is transported into the MISO market, additional reliability upgrades will likely be needed within MISO, both in and outside the ENO transmission grid, in order to mitigate any reliability constraints that might result from the power sourced from the HVDC line into the City of New Orleans. Lastly, the SCTP is bidirectional in nature and, when market conditions dictate,[15] the power in the SCTP is as likely to flow towards the ERCOT market at times. This may impose an additional demand on the ENO system, depending on how closely the ENO system and the HVDC terminal have to be linked in order to implement the PPA contemplated by Dr. Stanton. In short, the Southern Cross project provides no benefits of any sort to New Orleans.

Q26. PLEASE RESPOND TO DR. STANTON'S CONTENTION, AT PAGES 44-48 OF HER TESTIMONY, THAT DISTRIBUTION UPGRADES ARE NEEDED IN LIEU OF NOPS TO ADDRESS OUTAGES.

A. While Ms. Stanton is not an engineer and has done no analysis regarding ENO's distribution system, it is worth pointing out that there is a difference between distribution outages, which are relatively localized, and transmission grid issues, which can lead to high impact, large scale outages. By way of analogy, outages stemming from transmission issues are akin to the interstate system being closed,

[15] For instance, it is likely that during hot summer days, with low wind generation in Electric Reliability Council of Texas ("ERCOT"), market conditions in ERCOT might make it attractive for the SCTP to transport power from the eastern terminal of the HVDC line into ERCOT, creating additional demand for power at the eastern terminal. This is also precisely when the ENO system could be least expected to be able to handle additional electricity demand.

which would cause traffic problems throughout the City. Distribution outages, on the other hand, are akin to a neighborhood street being closed, which will cause traffic problems for one neighborhood. Moreover, it should be noted that based on my understanding, as explained by Company witness Charles Rice, the Company has a capital budget aimed at improving the performance of its distribution system; but to be clear, distribution outage mitigation is a separate issue from the need for NOPS that has been discussed in my testimony.

Q27. ON PAGE 23 OF HIS DIRECT TESTIMONY, MR. LUCKOW STATES THAT THE SOUTHEAST LOUISIANA TRANSMISSION PROJECT WILL PROVIDE 650 MW OF ADDITIONAL IMPORT CAPABILITY AND GIVE ENO'S SERVICE AREA ACCESS TO ADDITIONAL RESOURCES IN MISO SOUTH. DO YOU AGREE?

A. This project is expected to eliminate constraints in western DSG and allow for more power to be imported into DSG, as Mr. Luckow has suggested, but it will not solve reliability issues in the eastern end of DSG, including the risk of cascading outages, which will be mitigated by NOPS. By way of analogy, adding additional traffic lanes between LaPlace and Kenner will not ease traffic concerns in New Orleans East.

Q28. AT PAGE 24 OF HIS DIRECT TESTIMONY, MR. LUCKOW ALSO SUGGESTS CAPACITY INTO THE LOAD POCKET STILL EXCEEDS PEAK DEMAND, EVEN WITH TWO TRANSMISSION OUTAGES. PLEASE RESPOND.

A. It appears that Mr. Luckow simply added the DSG tie line ratings then subtracted the two largest lines. Planning a transmission system in the DSG load pocket, however, is not nearly that simple. The reliability of the DSG load pocket involves more than simply adding up the thermal capabilities of the transmission tie-lines to determine whether the sum of the transmission line ratings is higher than the load to be served. Just because the total transmission lines ratings add up to 2,800 mega-volt amperes ("MVA") even with two tie-lines out does not necessarily mean that the transmission system upstream of the tie-lines is capable of transferring 2,800 MVA under contingency conditions without reliability issues.

Secondly, having a hypothetical transmission line with a 100 MVA rating does not mean that 100 MVA will flow on the line. Power flows through the interconnected transmission grid, according to the laws of physics, follow the path of least resistance from generation to load. Across a simple two-bus transmission system the real component of power transfer is proportional to the difference between the phase angles of the voltage phasors[16] on the two buses and inversely proportionate to the impedance of the line. So, the collective ratings or capacities of tie-lines does not equate to a transfer capability of the same amount. Some of the tie-lines will

[16] The voltage phasor is a complex number representing the sinusoidal voltage wave, described by the amplitude, the angular frequency and the initial phase of the voltage wave function. The voltage phasors are influenced by the generation and load in the system.

carry more power than others based on the relative impedance differences between the various tie lines and the relative differences in voltage phasors. The transfer capability of the interface of the load pocket will depend on the amount of power that can be transferred between generation outside of the load pocket and load inside the load pocket prior to a contingency in the transmission system resulting in either a voltage or a thermal violation in the grid.

Finally, simply looking at the tie rating or the transfer capability into the load pocket ignores the reliability constraints that might exist *within* the load pocket (*i.e.*, there is not an infinite transmission capability within the load pocket). These reliability constraints within the DSG load pocket, such as those resulting from the category P6 double contingency and that are alleviated by the NOPS, cannot be ascertained by simply summing the tie rating or even the transfer capability into the DSG load pocket. Therefore, the algebraic addition of the tie ratings does not constitute a reliability analysis and a detailed reliability assessment using a loadflow model of the transmission system, which has not been performed by any of the Joint Intervenor Witnesses, and which must be performed in order to determine the amount of load that can be served in the transmission grid reliably.

The Company has performed the necessary analysis and shared the results which indicate that the best and most effective option to provide reliable electric service to the City of New Orleans is to construct one of the NOPS options. From a transmission reliability perspective, the preferred option is the 226 MW CT as it unloads the transmission system more than any other option.

Q29. AT PAGES 30-31 OF HIS DIRECT TESTIMONY, MR. FAGAN SUGGESTS POTENTIAL INCREASES IN WIND CAPACITY IN MISO ZONE 1 CAN BE UTILIZED BY ENO TO MEET ITS RESOURCE NEEDS "ESPECIALLY WHEN TRANSMISSION LIMITATIONS ARE MINIMIZED." PLEASE RESPOND.

A. First, it cannot be seriously argued that resources in MISO Zone 1, which borders Canada, can be used to satisfy local reliability considerations in the City of New Orleans. Secondly, Mr. Fagan's theory, like everything else in his Direct Testimony, depends on speculation about many factors. He does not acknowledge the fact that Zone 1 is not currently export constrained, as the Capacity Export Limit ("CEL") was not binding in the 2017/18 capacity auction.[17] Moreover, assuming that there is an increase in capacity available for export in Zone 1 due to wind resources or for any other reason, there is a 3000 MW limit from MISO-Midwest to MISO-South that is imposed in the Planning Resource Auction[18] and operationally in the Day Ahead and Real Time energy markets on a non-firm basis.[19]

Thus, capacity exports to the whole of MISO South (not just ENO) are limited to 3000 MW should there be an economic driver to flow into MISO-South. None of the Multi Value Projects ("MVP") projects discussed by Mr. Fagan address the limited amount of capacity transfer capability between MISO-Midwest and MISO-South or the limited transfer capability into DSG, so when Mr. Fagan talks about the

[17] *See* Slide 5 of the following link: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20170510/20170510%20RASC%20Item%2002a%202017-18%20PRA%20Summary.pdf.

[18] *See Id.*, at Slide 7.

[19] *See Id.*, at Slide 7.

manner in which MVPs will "knit together the MISO region and allow broader access to resources into the rest of MISO to entities such as ENO and other MISO South load serving entities," Mr. Fagan is not painting the entire and correct picture.

Q30. AT PAGES 30 AND 31 OF HIS DIRECT TESTIMONY, MR. FAGAN SUGGESTS RELIABILITY IN NEW ORLEANS CAN BE MAINTAINED BY MEETING MISO ZONE 9 CAPACITY OBLIGATIONS, WHICH DO NOT INCLUDE A REQUIREMENT FOR NEW ORLEANS GENERATION. PLEASE RESPOND.

A. Mr. Fagan, because he has never planned transmission in this area, seems unfamiliar with the nature of a load pocket. Zone 9 of MISO is essentially the state of Louisiana and Texas, and Mr. Fagan seems unable to appreciate that the grid in Amite South and DSG are different than the areas in MISO with which he may be familiar. In Amite South and DSG, reliability is heavily dependent on local generation because transmission import capability into these load pockets is limited. This is widely recognized by MISO, the Council's Advisors, and even Mr. Lanzalotta at page 5 of his Direct Testimony (stating that DSG is an area of concentrated load which depends on local generation to serve a portion of its load at various times under certain system conditions because of capacity limitations of the transmission lines connecting the load pocket with the rest of the system).

Thus, even if enough capacity in Zone 9 exists, which is uncertain given that MISO is projecting equilibrium starting in 2023 as discussed by Company witness Seth Cureington, there may not be enough capacity in the Amite South and DSG load pockets to ensure reliability in those areas because of transmission limitations into the load pockets. For instance, a resource in the western or northern parts of Zone 9, such near the cities of The Woodlands, Texas or Monroe, Louisiana, respectively, will not be helpful in serving customers in the City of New Orleans.

Mr. Fagan then states that "reliability associated with transmission system security can be ensured by reinforcement of existing transmission system elements." Adopting Mr. Fagan's strategy would require that deliverability from these resources into New Orleans be greatly improved. Such a strategy would require either building or upgrading numerous miles of the transmission grid, far more than the five transmission line upgrades that I have listed in Table 1 of my Supplemental and Amending Direct Testimony. Such a strategy would be cost prohibitive and involve operational challenges that would render such a plan to be practically unworkable.

Q31. MESSRS. FAGAN AND LANZALOTTA BOTH FOCUS EXCLUSIVELY ON NERC REQUIREMENTS, INSISTING THAT NERC DOES NOT REQUIRE LOCAL GENERATION AND THAT ENO SHOULD ACCORDINGLY JUST FOCUS ON CONSTRUCTING TRANSMISSION UPGRADES TO MEET NERC REQUIREMENTS. PLEASE RESPOND.

A. It should first be noted that Mr. Fagan and Mr. Lanzalotta have no answers to the current and persisting reliability risks, including the risk of cascading outages, and constructing these transmission facilities would likely expose customers to these risks for many years longer than needed if a NOPS alternative were to be constructed. Accordingly, even if ENO's goal were simply to achieve the bare minimum level of reliability compliance to avoid being fined by the U.S. Electric Reliability

Organization, which it is not, constructability issues would prevent the Company from achieving that minimum level until long after a NOPS alternative could be put in place, exposing customers in the meantime.

Secondly, even assuming that ENO could eventually overcome the constructability issues, which is doubtful, it is well settled that the NERC TPL 001-4 standard sets a minimum level of reliability—a level necessary to prevent reliability issues that affect the larger electric grid. But there are local reliability considerations, especially for a relatively small utility like ENO, that justify obtaining reliability margins that exceed NERC compliance.

For example, MISO operates the transmission system in the southern load pockets in a manner that exceeds the NERC operational reliability standard. For instance, because the simultaneous loss of a generation resource and a transmission element in the DSG region was often observed to result in voltage and thermal constraints, which cannot be mitigated without the commitment of another local unit in DSG (all of the legacy generators in DSG have long start-up times), MISO has implemented commitment guides in DSG to ensure reliable electric service during the simultaneous outage of a transmission branch and a generation resource. These commitment rules, known as Voltage and Local Reliability ("VLR") operating guides, are based on the mitigation of constraints resulting from the simultaneous outage of a transmission branch and a generation resource, are more stringent than that required by the NERC operational reliability standard. These commitment guides ensure that enough committed capacity exists in the DSG region to maintain reliability despite the fact that another unit inside or outside the region may be more economic. It should also be noted that, as stated in my Direct Testimony, the Michoud units were designated VLR units, and the NOPS unit, if constructed, will very likely be designated a VLR unit as well.

Moreover, Mr. Lanzalotta provides another example that illustrates the Company's point when he attempts to address storm risks in his testimony by recommending that the Council pursue the undergrounding of transmission lines, which as described above, is not a practical or cost effective approach for ENO. In making this recommendation, however, Mr. Lanzalotta demonstrates that it is sometimes important to go beyond the plain vanilla NERC requirements to address local considerations, as none of the NERC standards require the undergrounding of lines to address the threat of storms. Accordingly, the Joint Intervenors Witnesses would seemingly support going beyond the NERC requirements to mitigate practical, real-world local concerns – as long the mitigation measure does not involve the construction of a gas-fired generator.

Q32. MR. MOVISH, ON PAGE 5 OF HIS DIRECT TESTIMONY, OBSERVES SOME INCONSISTENCIES IN THE ASSUMPTIONS USED IN ENO'S TRANSMISSION AND ECONOMIC ANALYSES, AND STATES THAT THE IMPACT OF THESE INCONSISTENCIES IS UNKNOWN. PLEASE RESPOND.

A. A review of Mr. Movish's Direct Testimony, coupled with various discovery requests sent to the Company by the Council's Advisors, revealed an error in the amount of DSM contained in load forecast that incorporated the Council's 2% goal for purposes of the transmission analysis. It is important to note that rather than affecting all of the cases analyzed by the Company in its reliability analysis, this error only affected those cases that contained the 2% goal. First, as aforementioned, it should be reiterated that reliance on DSM to address reliability needs is very risky and should be done with extreme caution because the savings assumed may not be actually realized, which could lead to serious reliably issues if the Company depended on those savings for reliability purposes.

Moreover, the Company has corrected the DSM assumptions in the transmission cases affected and there were no material changes. To begin with, only two cases could have been materially affected by this change, the first of which involved Case B2, which contained 200 MW of solar at the Michoud site, plus 2% incremental DSM. This was the only case contained in my Supplemental and Amending Direct Testimony that contained the 2% DSM goal, and that also required transmission investment. In that case, with the corrected DSM assumptions that properly account for the 2% DSM goal, the same transmission investment would be required.[20]

The second case that could have potentially been affected is a scenario that was requested by the Joint Intervenors, which modeled the 2% goal without any other resource additions. In that case, the corrected DSM assumptions still lead to cascading outages in the system through 2024, with less significant transmission issues occurring thereafter. Given the sustained exposure to the risk of cascading

[20] *See* corrected transmission case B2, attached hereto as Exhibit CWL-7.

outages for ENO customers through 2024 in this scenario, the Company would make the same transmission investment if this scenario came to fruition as well.[21]

Q33. ON PAGE 5 OF HIS DIRECT TESTIMONY, MR. MOVISH ALSO POINTS OUT THAT THE COMPANY USED DIFFERENT CAPACITY ASSUMPTIONS FOR SOLAR IN ITS ECONOMIC AND TRANSMISSION ANALYSES. PLEASE EXPLAIN.

A. The economic analysis uses the assumption MISO uses solar resources in its capacity auction, which is 50%. In other words, MISO gives solar resources a 50% capacity credit in their first year of operation, but that amount changes to the actual capacity factor of the resource in the second year of operation. From a long-term transmission planning perspective, the Company used a 35% on peak capacity factor for the solar PV resources that it assumed at the Michoud facility, but it should also be noted that there are times at the summer peak hour (for which reliability analyses are typically performed) when a solar resource will have a capacity factor that is substantially below 35%, so it is extremely difficult to judge what value to give these resources in reliability analyses. The Company also states that there are legitimate reasons to be more conservative with this value in its transmission reliability assessments than the capacity factor assumption in resource adequacy assessments because if the capacity factor associated with solar resources assumed in the economic analysis turns out to be overstated, the consequence is financial cost to customers in the form of exposure

[21] *See* corrected transmission case 2% DSM-only, attached hereto as Exhibit CWL-8.

to the spot energy market prices to replace the output from the solar resources. With respect to transmission reliability analyses, however, the consequences of using the wrong assumptions could lead to customer outages because there is no back-up market for reliability and no means of obtaining additional transmission capacity in the electricity market.

Additionally, it is also extremely unlikely that 200 MW of solar PV, or 100 MW for that matter, can be located in or around the Michoud area, where it is needed for reliability purposes. Thus, the Company states that the entire scenario that involves solar at the Michoud facility, plus 2% DSM, rests on so many unrealistic assumptions that the case is hardly useful.

Q34. MR. MOVISH ALSO ASSERTS THAT HE HAS PERFORMED A REVIEW THAT LEADS HIM TO CONCLUDE THAT THE NOPS FACILITY MAY BE ABLE TO PROVIDE POWER TO THE SEWAGE AND WATER BOARD'S PUMPS IN THE EVENT THE CITY AND THE SEWAGE AND WATER BOARD'S INTERNAL ELECTRICAL INFRASTRUCTURE HAVE LOST POWER. DO YOU CONCUR?

A. Yes. The Company performed a preliminary assessment of a scenario involving a complete loss of power in the City and within the S&WB's facilities, incapacitating the storm pumps in the City. ENO's analysis involved exploring the possibility of black-starting the RICE NOPS resource, followed by energizing a cranking path from the Michoud substation to ENO's Joliet substation and supplying start-up power to the S&WB's facility in order to start the pumps located within the S&WB facility. ENO's analysis consisted of two different reliability assessments:

- A steady-state reliability analysis to determine whether the cranking path from the RICE units at Michoud to Joliet and the process of starting the S&WB motors results in an unacceptable over-voltage condition due to the lightly loaded transmission lines along the cranking path from Michoud to Joliet. The results of this analysis indicated that there were no over-voltages observed in the study scenario. Notably, the proposed RICE resource would have more than sufficient generation capacity to be able to generate enough power to serve the entire S&WB load that is served out of Joliet substation.
- A dynamic time-domain stability analysis to analyze the process of starting the S&WB motor at Joliet substation through the cranking patch from the RICE units at Michoud in order to determine whether the motors will be able to start successfully and whether the voltages recover satisfactorily following the motor start. This analysis indicated that even the largest motor at the S&WB Station was able to start successfully and that the voltage at the Joliet substation recovered satisfactorily following the motor start.

Should the Council approve the NOPS resource, the Company would then conduct more detailed analysis in order to ensure that no additional steps may be needed to implement such a plan.

Q35. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF MISSISSIPPI

COUNTY OF Hinds

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES W. LONG**, who after being duly sworn by me, did depose and say:

That the above and 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.

Charles W. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 16th DAY OF NOVEMBER, 2017

Aletta B Walker
NOTARY PUBLIC

My commission expires: 6/22/20

ALETTA B WALKER
NOTARY PUBLIC
ID No. 116794
Commission Expires
Jun 22, 2020
STATE OF MISSISSIPPI
MADISON COUNTY

Exhibit CWL-7
CNO Docket No. UD-16-02
Page 1 of 8

Contents

The following slides contain the thermal and voltage reliability violations that were observed in the transmission system for the following scenario in the 2019, 2024, and 2027 study years:

- Requested Case B2 which includes a 100 MW solar facility with the requested 2% DSM goal, the updated load forecast and another 100 MW solar facility (assumed to have been selected in the IRP as the most optimal resource).
  - The 100 MW solar resources are each dispatched at 35% of the maximum capacity of the resources for the purpose of this reliability assessment which was performed for an hour of the study year representing the forecasted summer peak demand.
  - The solar resources are assumed to be interconnected at Michoud.
- All MTEP16 A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.
- The 2024 and 2027 analyses years assume a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center at the Bogalusa substation.

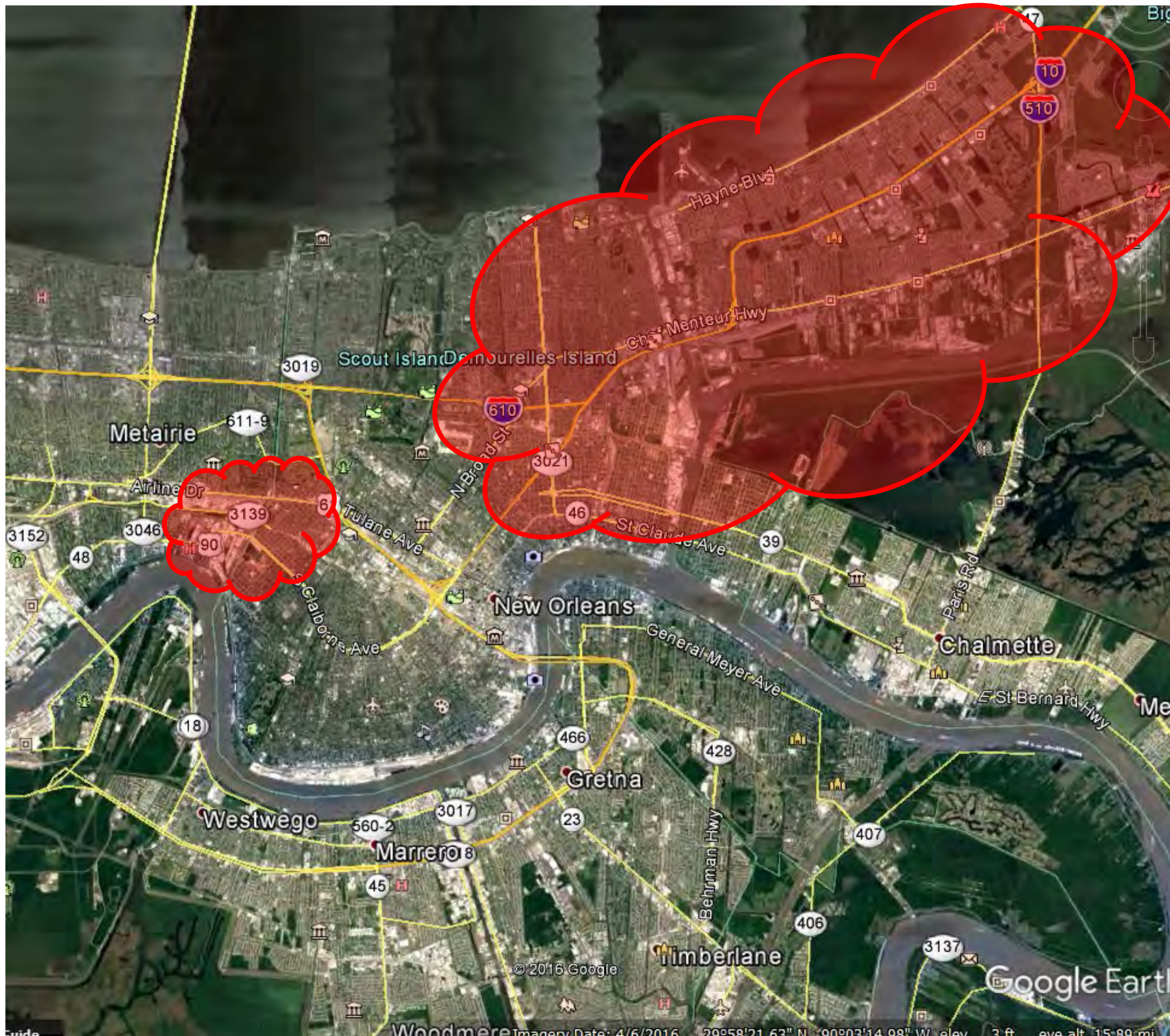
Results of reliability analysis

2019 Requested Case B2

The following reliability constraints are observed in this scenario:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from approx. 107% to 117% on four different transmission lines.



Legend:

Geographical extent of reliability constraints resulting from the breaker failure contingency

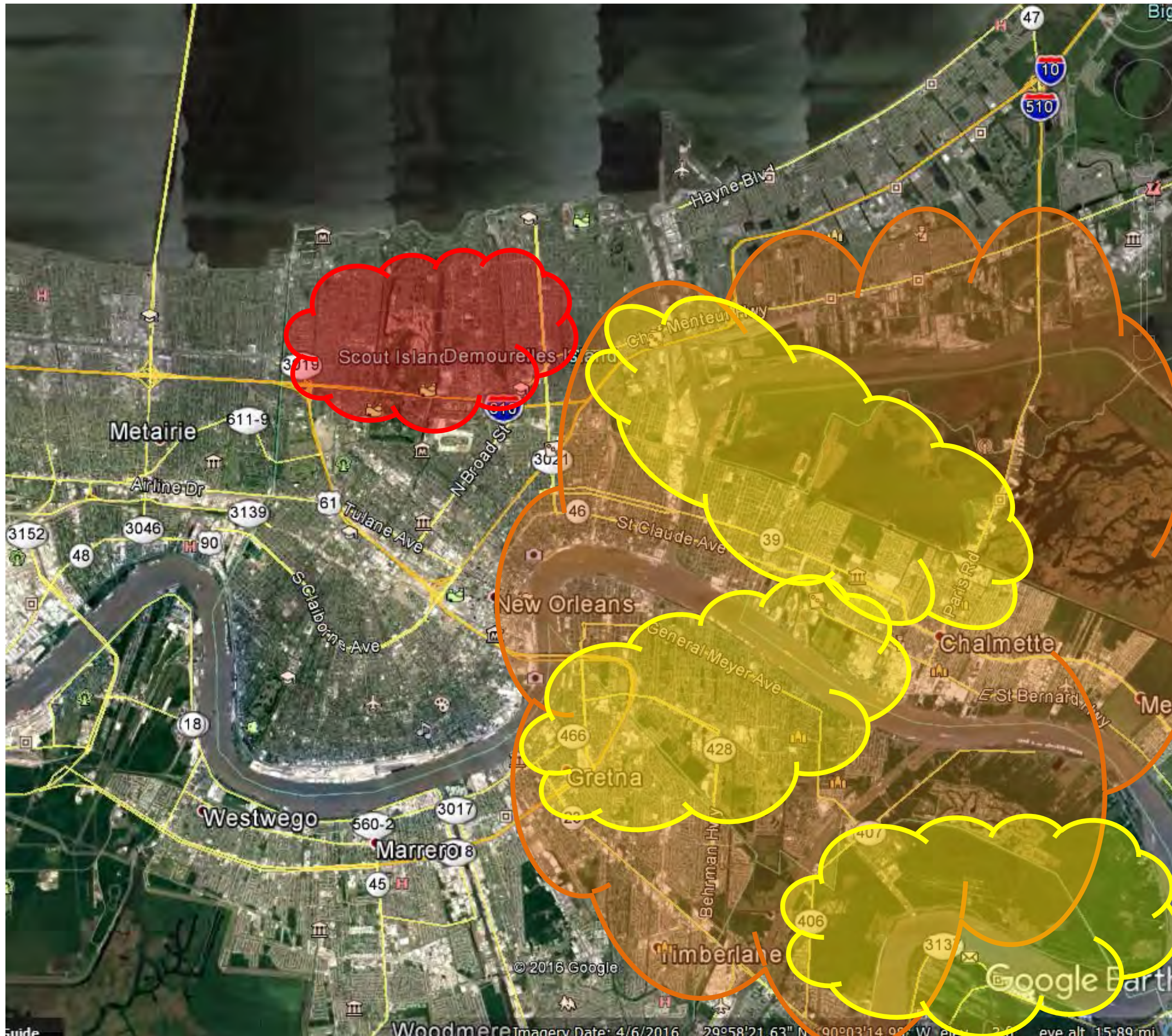
Results of reliability analysis

2019 Requested Case B2

Furthermore, the following additional reliability constraints are observed in this scenario:

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in red).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.



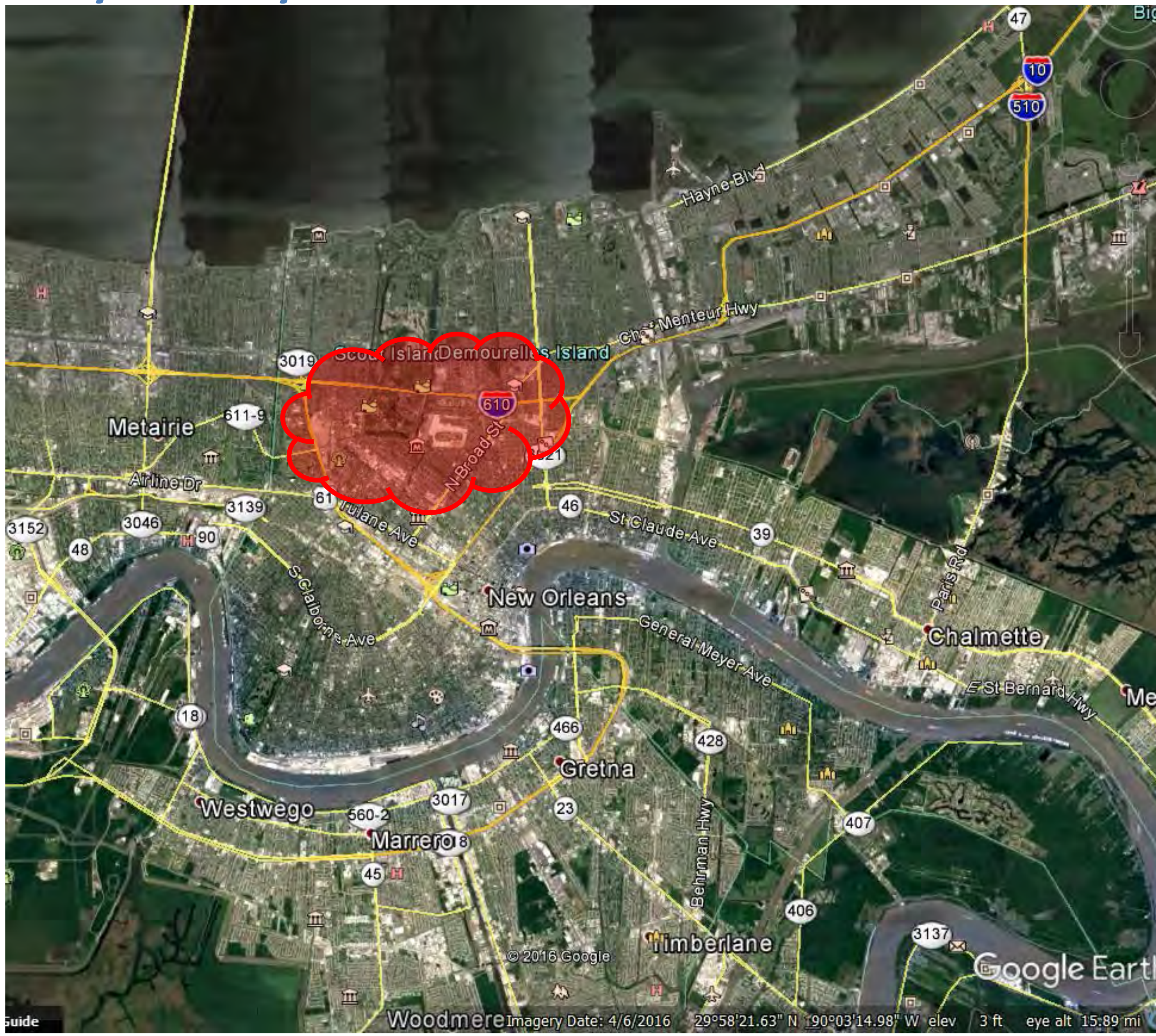
Legend:
Primary overload
Secondary overload
Region of anticipated load shed

Results of reliability analysis

2024 Requested Case B2

The following reliability constraints are observed in this scenario:

- The contingency involving the failure of a breaker, that had resulted in constraints in the 2019 study year, no longer results in constraints in 2024, though the lines remain very heavily loaded.
- Two sequential outages (a category P6 contingency) results in an overloaded transmission line (shown in the region encircled in red).



Legend:
Primary overload

NOTE: There are several projects in the DSG area with projected in-service dates in that reduce the overloads observed in the system after 2019. These projects include, but are not limited to, the Jefferson Parish Reliability Plan and the Paris Tap to Avenue C 115 kV rebuild project.

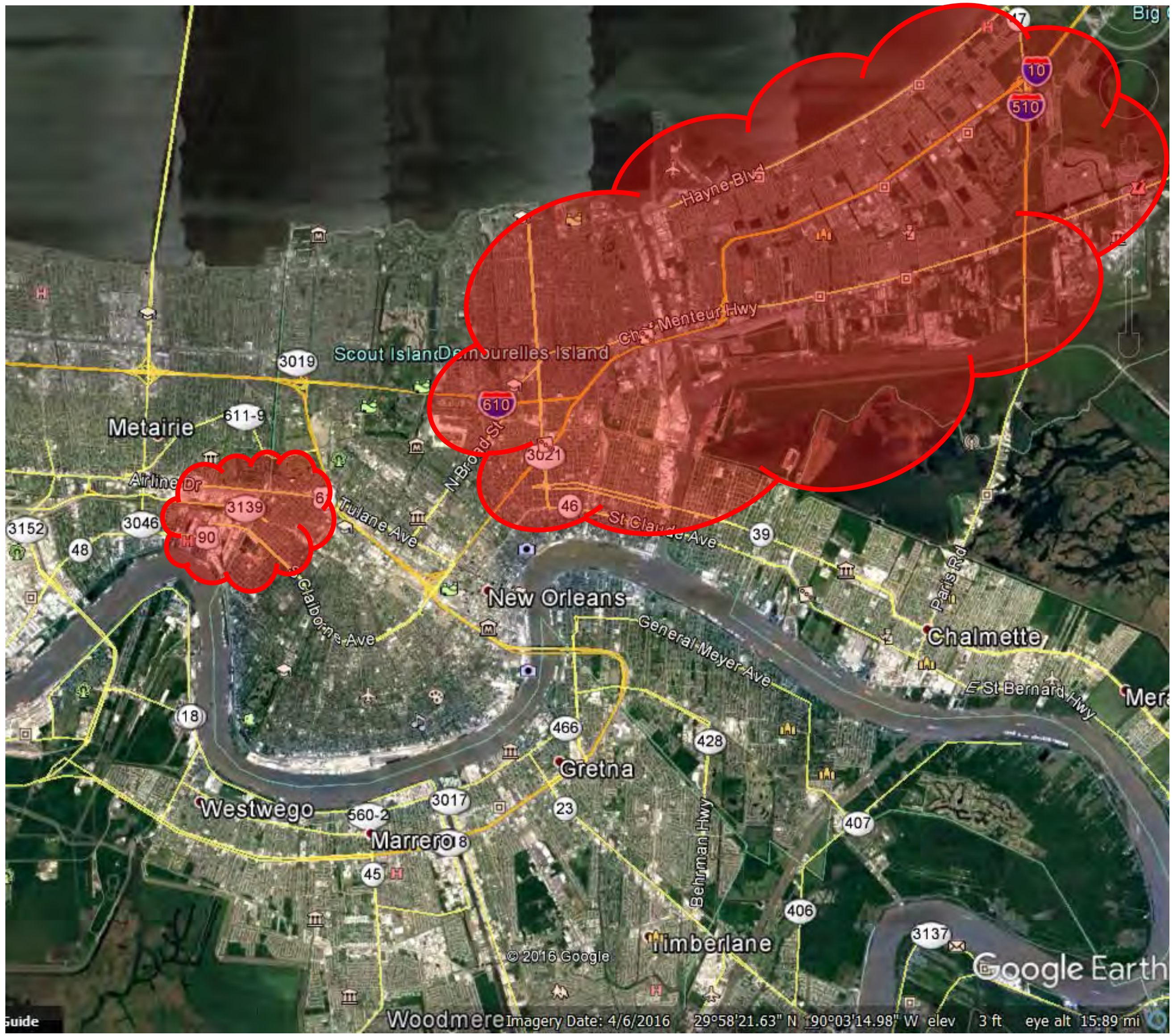
Results of reliability analysis

2027 Requested Case B2

The following reliability constraints are observed in this scenario:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from approx. 101% to 104% on two different transmission lines.



Legend:

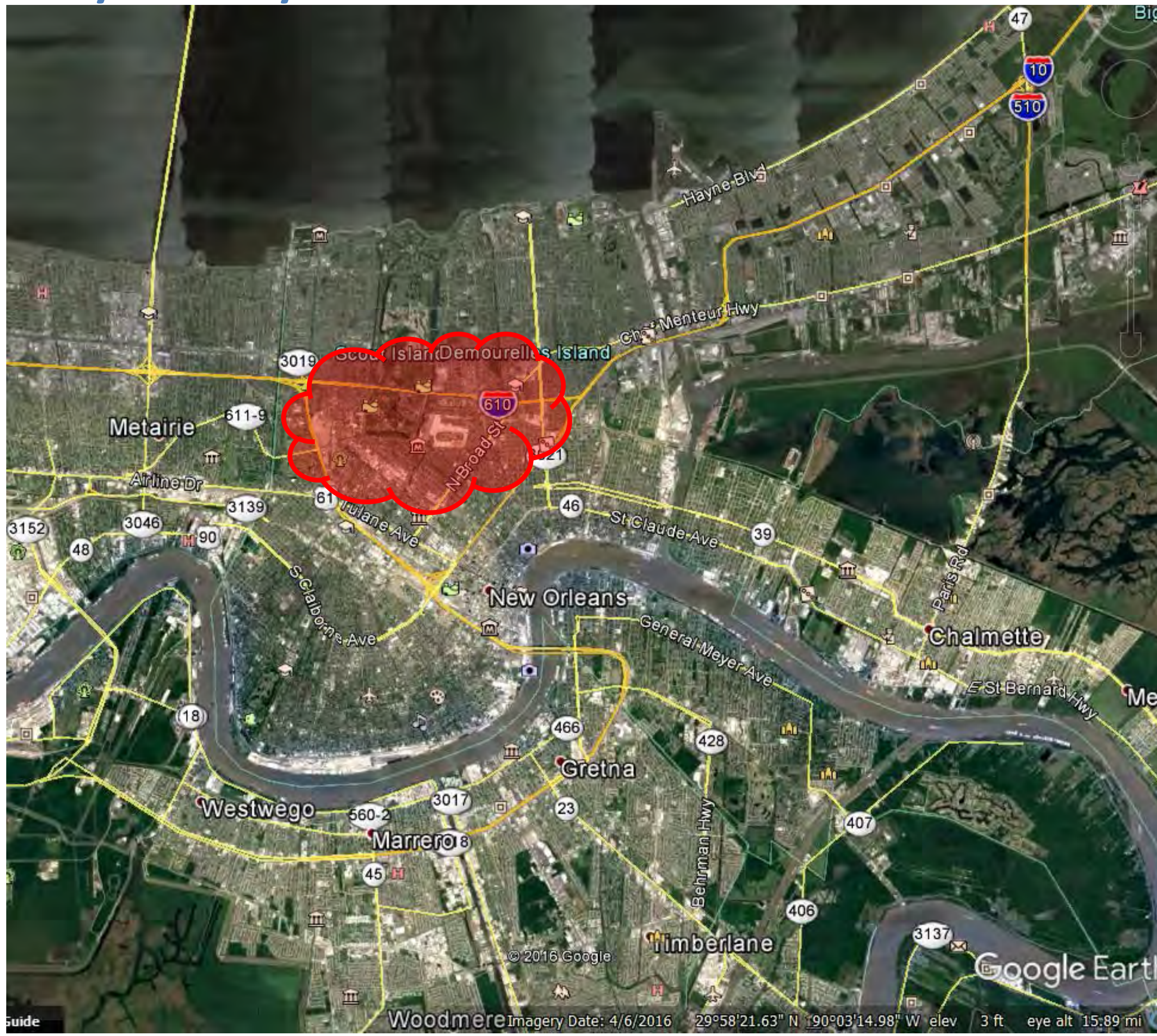
Geographical extent of reliability constraints resulting from the breaker failure contingency

Results of reliability analysis

2027 Requested Case B2

Furthermore, the following reliability constraints are observed in this scenario:

- Two sequential outages (a category P6 contingency) results in an overloaded transmission line (shown in the region encircled in red).



Legend:
Primary overload

NOTE: There are several projects in the DSG area with projected in-service dates in that reduce the overloads observed in the system after 2019. These projects include, but are not limited to, the Jefferson Parish Reliability Plan and the Paris Tap to Avenue C 115 kV rebuild project.

Results of reliability analysis

<u>Requested Case B2</u>

In order to mitigate the constraints observed in the system if the scenario contemplated in Requested Case B2 (i.e., a 100 MW solar resource, 2% DSM goal and another 100 MW solar resource selected in the IRP) were to materialize , the following transmission upgrades would have to be constructed:

Project	Voltage	Total Project Cost
Almonaster to Curran Line Upgrade	230kV	$18,050,000
Southport to Joliet Line Upgrade	230kV	$5,125,000

Corrected Results of the transmission reliability analysis of the No NOPS + 2% DSM Scenario for the 2019, 2024 and 2027 Study Years

Exhibit CWL-8
CNO Docket No. UD-16-02
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Contents

The following slides contain the thermal and voltage reliability violations that were observed in the transmission system for the following scenario in the 2019, 2024, and 2027 study years:

- No generation facility at Michoud, with the requested 2% DSM goal and the updated load forecast.
- All MTEP16 A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.
- The 2024 and 2027 analyses years assume a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center at the Bogalusa substation.

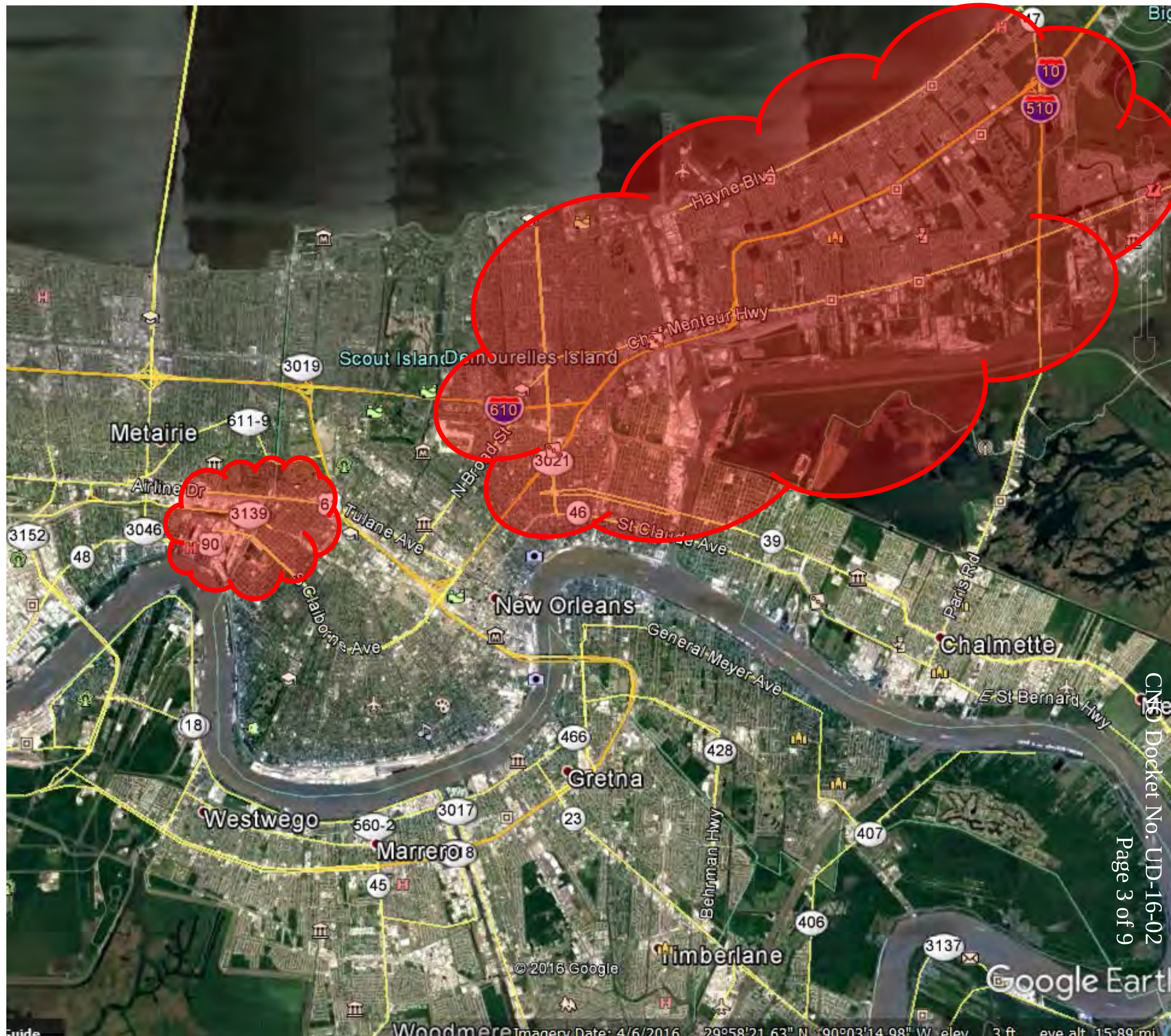
Results of reliability analysis

2019 No NOPS + 2% DSM

The following reliability constraints are observed in this scenario:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from approx. 112% to 121% on four different transmission lines.



Legend:

Geographical extent of reliability constraints resulting from the breaker failure contingency

Exhibit CWL-8
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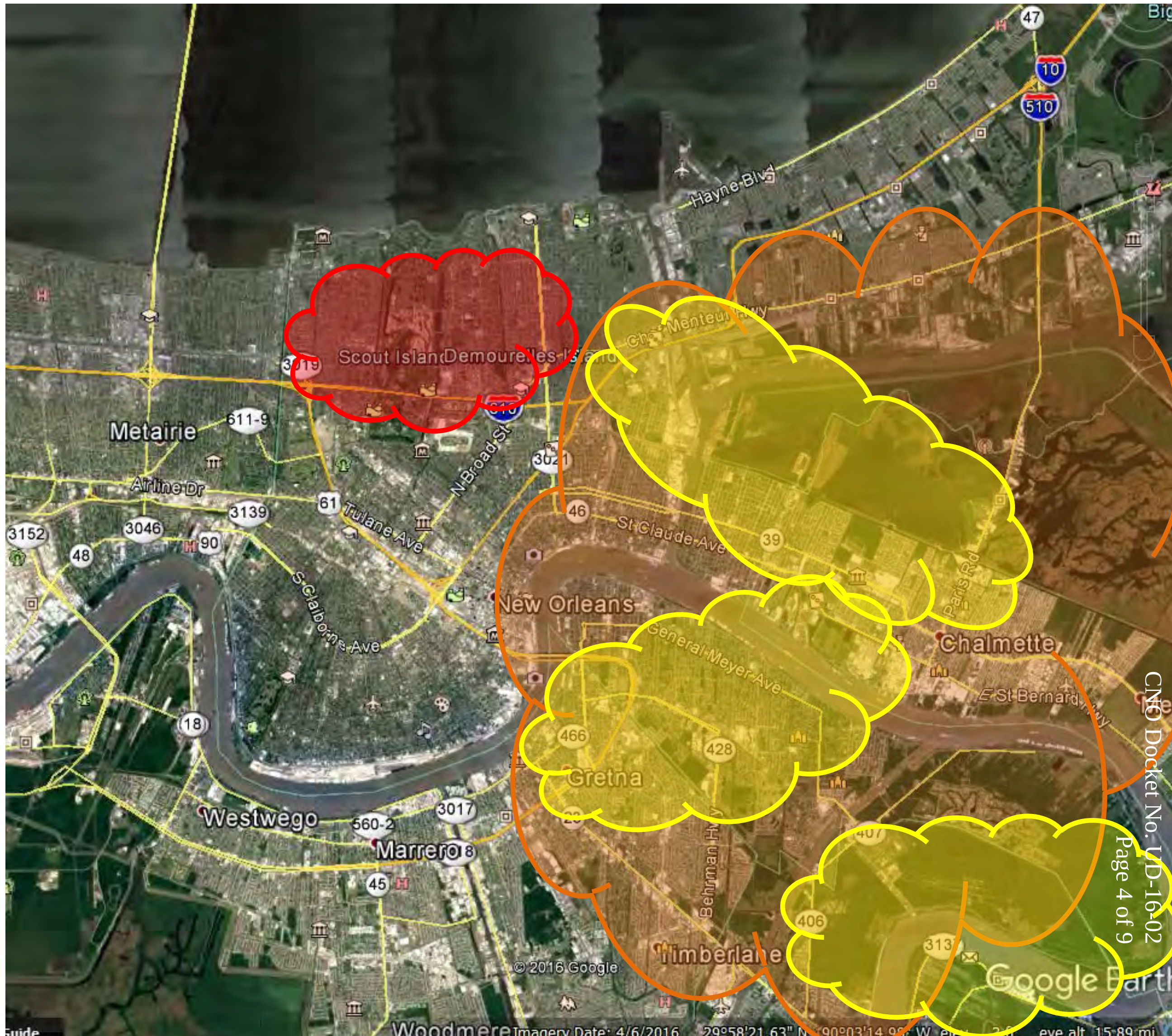
Results of reliability analysis

2019 No NOPS + 2% DSM

Furthermore, the following additional reliability constraints are observed in this scenario:

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in red).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.



Legend: Primary overload Secondary overload Region of anticipated load shed

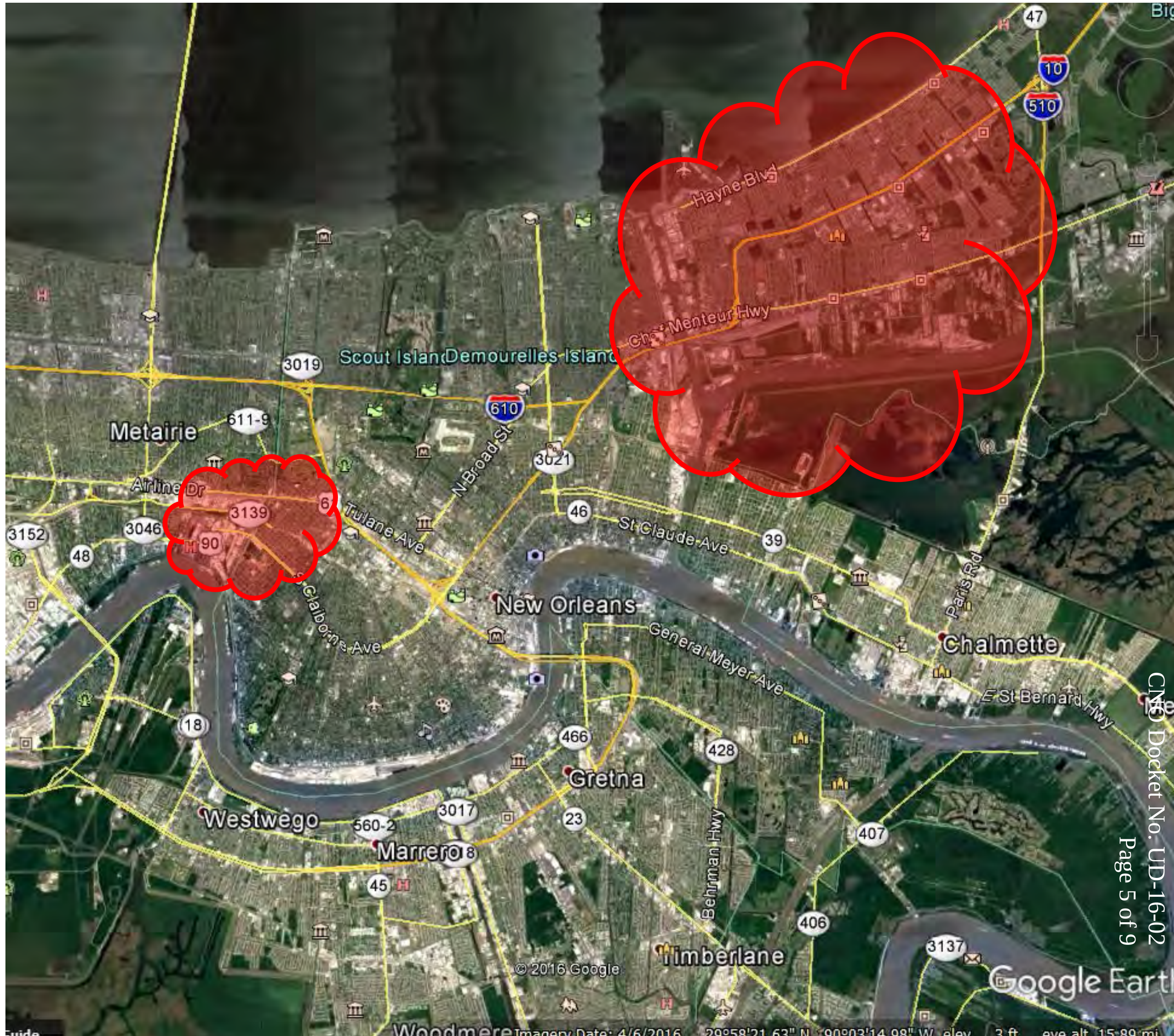
Exhibit CWL-8
CNO Docket No. UD-16-02
Page 4 of 9

Results of reliability analysis

<u>2024 No NOPS + 2% DSM</u>

The following reliability constraints are observed in this scenario:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.
- The overloads were moderate around 101% on two different transmission lines.



Legend:

Geographical extent of reliability constraints resulting from the breaker failure contingency

Exhibit CWL-8
CNO Docket No. UD-16-02
Page 5 of 9

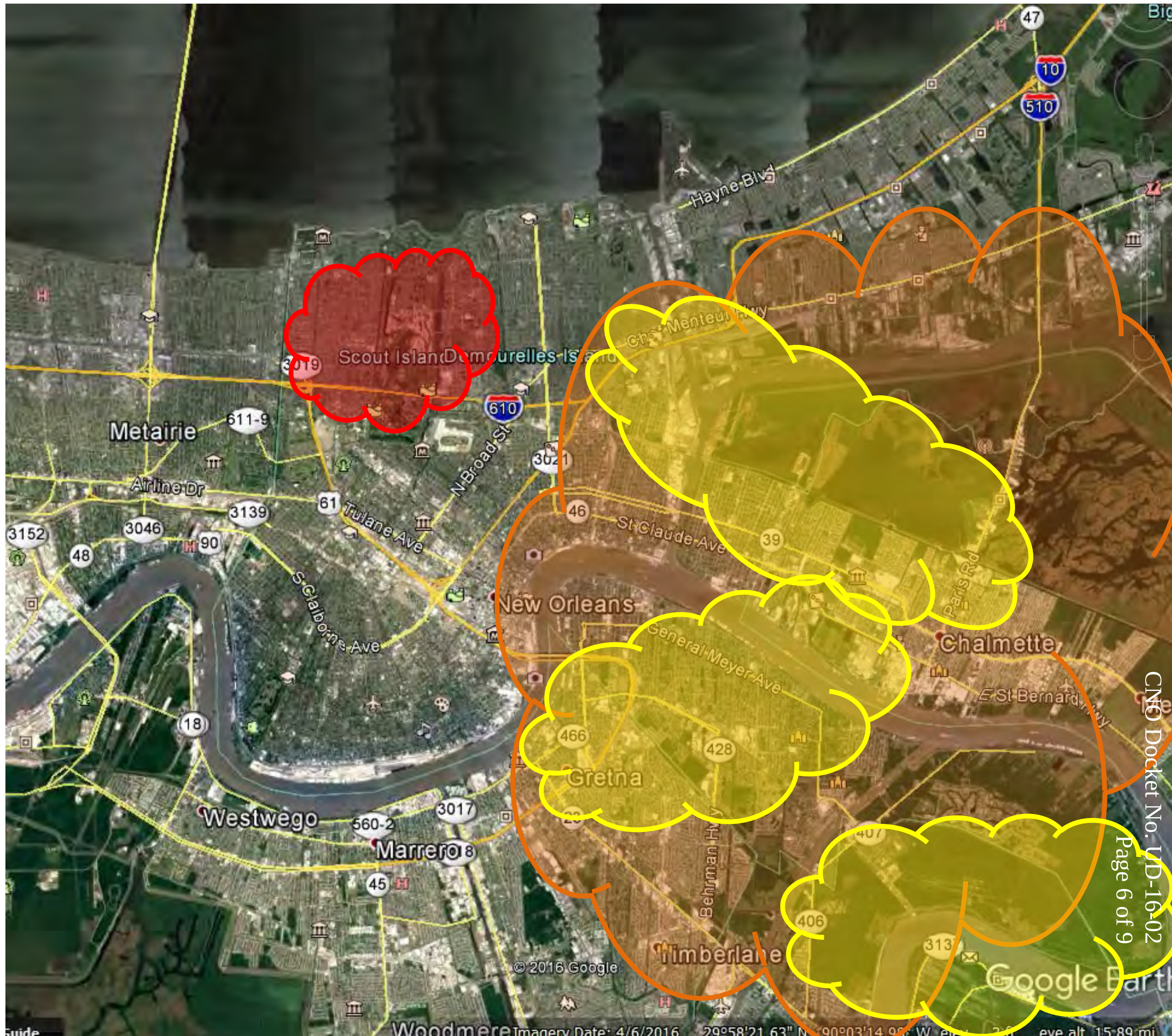
Results of reliability analysis

2024 No NOPS + 2% DSM

Furthermore, the following additional reliability constraints are observed in this scenario:

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in red).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.



Legend:
Primary overload
Secondary overload
Region of anticipated load shed

Exhibit CWL-8
CNO Docket No. UD-16-02
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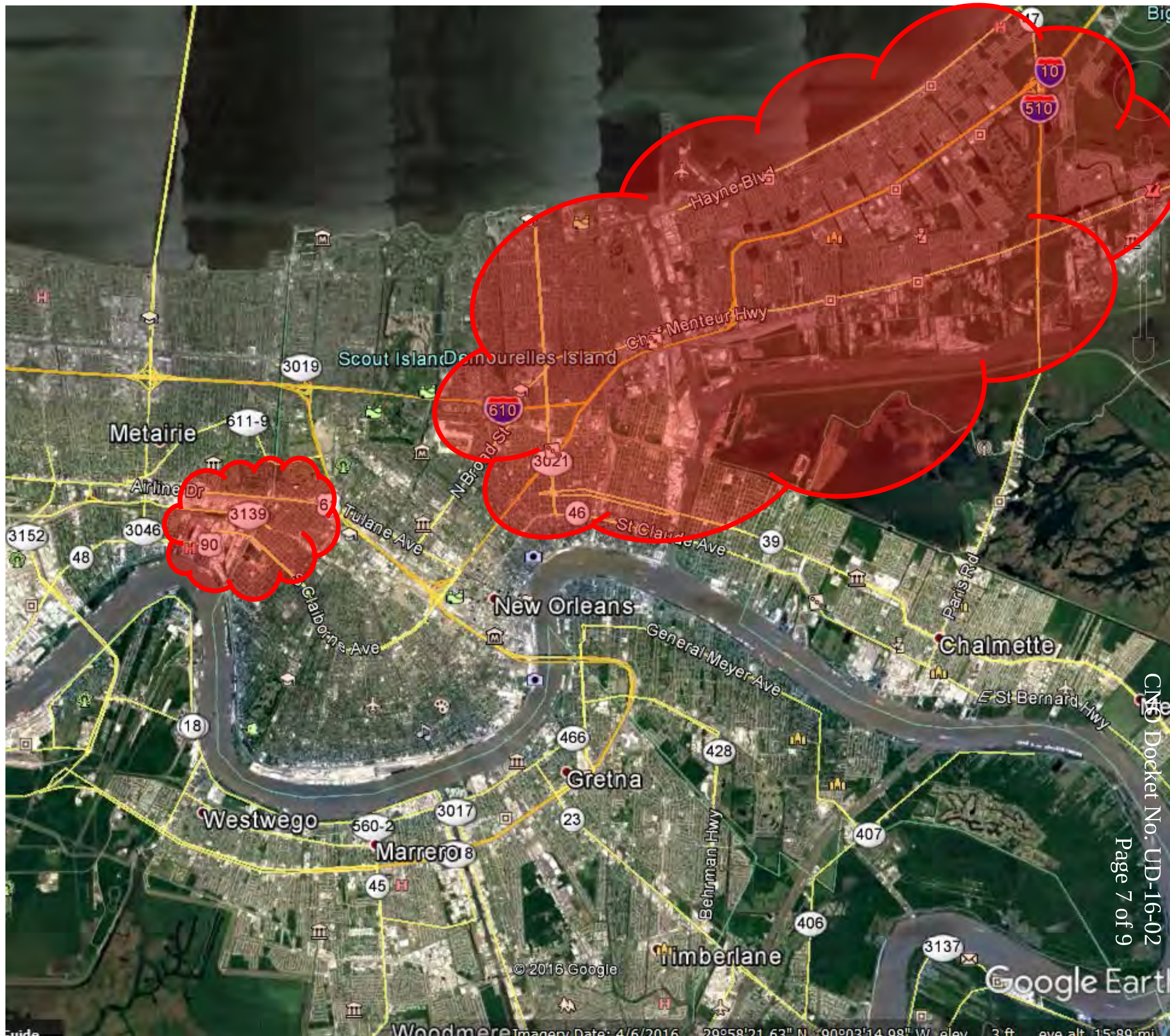
Results of reliability analysis

2027 No NOPS + 2% DSM

The following reliability constraints are observed in this scenario:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from just above 100% to 108% on three different transmission lines.



Legend:

Geographical extent of reliability constraints resulting from the breaker failure contingency

Exhibit CWL-8
CNO Docket No. UD-16-02
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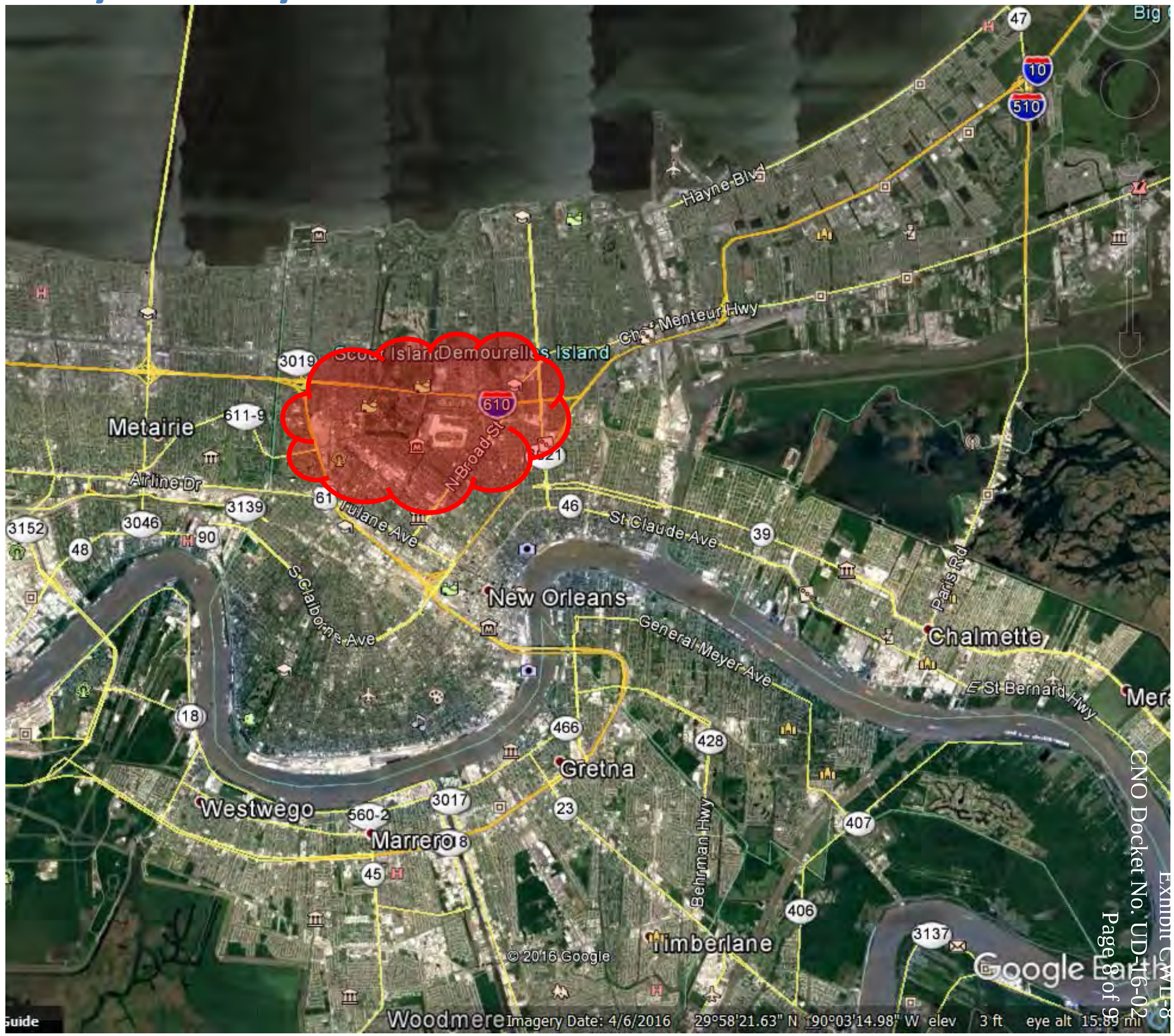
Results of reliability analysis

2027 No NOPS + 2% DSM

Furthermore, the following reliability constraints are observed in this scenario:

- Two sequential outages (a category P6 contingency) results in an overloaded transmission line (shown in the region encircled in red).



Legend:

Primary overload

NOTE: There are several projects in the DSG area with projected in-service dates in that reduce the overloads observed in the system after 2019. These projects include, but are not limited to, the Jefferson Parish Reliability Plan and the Paris Tap to Avenue C 115 kV rebuild project.

Exhibit CWL-8
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Results of reliability analysis

<u>No NOPS resource with 2% DSM</u>

In order to mitigate the constraints observed in the system in the absence of any incremental generation in New Orleans, the following transmission upgrades would have to be constructed:

Project	Voltage	Total Project Cost
Avenue C to Pauger Line Upgrade	115kV	$21,050,000
Michoud to Curran Line Upgrade	230kV	$100,000
Almonaster to Curran Line Upgrade	230kV	$18,050,000
Southport to Joliet Line Upgrade	230kV	$5,125,000

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	))))))	**DOCKET NO. UD-16-02**

REBUTTAL TESTIMONY

OF

SHAUNA LOVORN-MARRIAGE

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

NOVEMBER 2017

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. A. My name is Shauna Lovorn-Marriage. My business address is Entergy Services, Inc. ("ESI"), 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ARE YOU THE SAME SHAUNA LOVORN-MARRIAGE WHO FILED DIRECT TESTIMONY IN THIS DOCKET (JUNE 2016) IN SUPPORT OF ENTERGY NEW ORLEANS, INC.'S APPLICATION FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF?

A. Yes, I am. However, since the filing of my Direct Testimony in the docket, I have assumed the role of Vice President, Regulatory Services, ESI. In that role, I have oversight of preparation and support of regulatory filings and regulatory analysis for all of the Entergy Operating Companies.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING AT THIS TIME?

A. I am testifying before the Council of the City of New Orleans (which I sometime refer to here as "CNO" or the "Council") on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to support ENO's Application seeking approval to construct the New Orleans Power Station ("NOPS"), a 226 megawatt ("MW") combustion turbine ("CT") generating unit to be located at the Company's Michoud generating facility in New Orleans, Louisiana or, alternatively, seven Wartsila 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker"). I also respond to certain arguments, positions, and recommendations made by the Council's Advisors ("Advisors") through the Direct Testimony of witnesses Joseph A. Vumbaco, P.E. and Victor M. Prep, P.E.; Air Products and Chemicals, Inc. ("Air Products") through the Direct and Supplemental Direct Testimony of its witness, Maurice Brubaker; and the Alliance for Affordable Energy, Deep South for Environmental Justice, and 350 Louisiana – New Orleans and Sierra Club, whom I refer to collectively throughout my Rebuttal Testimony as the ("Joint Intervenors"), through the pre-filed Direct Testimony of their witnesses, Dr. Elizabeth A. Stanton and Philip Henderson.

Q5. WHAT SPECIFIC ARGUMENTS, POSITIONS AND RECOMMENDATIONS OF THE PARTIES ARE YOU ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. I address the positions and recommendations offered by Messrs. Vumbaco, Prep and Brubaker regarding ENO's recovery of the non-fuel revenue requirement associated with the NOPS CT or Alternative Peaker, should either alternative be approved by the

Council. Also, I address the Council Advisors' position regarding the recovery of the costs of a Long-Term Service Agreement ("LTSA") to support the CT. Additionally, I address the notion offered by Air Products and the Joint Intervenors that it is necessary for ENO to initiate a Request for Proposals ("RFP") or "all-source solicitation" process to enable ENO and the Council to determine what resource(s) will best serve the public interest in delivering the required capacity and energy to meet the load requirements of the City of New Orleans.

Q6. PLEASE SUMMARIZE YOUR PRIMARY RESPONSES TO THE ADVISORS' AND AIR PRODUCTS' POSITIONS REGARDING THE PROPOSED COST RECOVERY FOR THE NOPS PROJECT.

A. The Direct Testimony of the Council's Advisors recognizes that the principles of sound regulation dictate that ENO has a right to a reasonable opportunity to recover its investment and a fair return.[1] The Company interprets the proposals made by the Advisors as an attempt to propose recovery mechanisms that comply with those sound regulatory principles, but states that further details regarding their proposals are necessary in order to determine whether the proposed mechanisms are fully aligned with those principles. ENO understands the Advisors' testimony to recommend that, should the Council determine NOPS to be in the public interest, ENO is authorized to include the NOPS revenue requirement in the upcoming Combined Rate Case

[1] Direct Testimony of Joseph A. Vumbaco, P.E., on behalf of the Advisors to the Council of the City of New Orleans, Council Docket No. UD-16-02 (November 20, 2017) ("Vumbaco Direct Testimony"), p. 30; Direct Testimony of Victor M. Prep, P.E., on behalf of the Advisors to the Council of the City of New Orleans, Council Docket No. UD-16-02 (November 20, 2017) ("Prep Direct Testimony"), p. 12.

through a pro-forma adjustment that would provide for cost recovery in the form of a second step adjustment to base rates in the first full billing month following the unit's Commercial Operation Date ("COD"). Currently, there are two generation alternatives before the Council for consideration. Although the Company respectfully maintains its request for a modified exact cost recovery mechanism to recover the NOPS revenue requirement, if I have correctly restated the manner in which the Advisors' two-step cost recovery proposal would work, the Company agrees that it could provide a sound mechanism for the recovery of the revenue requirements associated with the Alternative Peaker. However, with respect to the potential construction schedule of the NOPS CT alternative, further clarification of the Advisors' cost recovery proposal would be necessary to determine whether this recovery scenario fully aligns with the objectives that have been articulated for the mechanism.

Overall, it is important to bear in mind that if ENO is to undertake a project on the scale of either NOPS alternative, which would be the first of its kind in over 40 years, ENO must have assurances that it will have a reasonable opportunity to recover its investment and its allowed return. Although it is true that ratemaking can be accomplished in many ways, as Mr. Prep has suggested, if the proposed recovery mechanism does not allow for contemporaneous in-service implementation, regulatory lag on a $211-240 million investment will greatly reduce ENO's opportunity to earn its allowed (fair) return on that investment, creating unacceptable financial uncertainty for ENO. Further, as described by Company witness Orlando

Todd, for a company of ENO's size, prolonged regulatory lag on recovery of this substantial investment could severely limit ENO's ability to make other required investments and respond to emergency conditions.

ENO reiterates its position that a modified PPCACR Rider would provide the greatest flexibility in meeting the objectives of providing ENO a reasonable opportunity to recover the investment and a fair return associated with either NOPS alternative, while adhering to traditional principles of ratemaking and taking into consideration regulatory efficiency. ENO agrees with Mr. Prep and Mr. Brubaker that the methodology employed by the current Purchased Power and Capacity Acquisition Cost Recovery ("PPCACR") Rider for allocating costs should be re-examined in the context of ENO's upcoming Combined Rate Case. At this time, I am not endorsing one method of allocation over another, as I believe that determination should be left for examination in the Combined Rate Case.

If the modified PPCACR Rider were to be implemented at the same time as a Formula Rate Plan ("FRP") in connection with the results of the Combined Rate Case, there should be no concern regarding single issue ratemaking, as all revenues and expenses would be taken into account in establishing ENO's rates for a given period. The Combined Rate Case provides an opportunity for the PPCACR Rider to be restructured in a manner that comports with more traditional allocation methodologies, a restructuring that ENO supports. A modified PPCACR Rider would establish a reasonable and appropriate mechanism by which future resource additions approved by the Council may be recovered, *e.g.*, ENO's currently proposed rooftop solar project, without the need for multiple, inefficient, pancaked rate cases that may be required in the absence of an FRP (or equivalent mechanism) in periods of increasing capital investment. Ideally, an FRP structure agreed upon by the Company and the Council would be the most expeditious and balanced framework for addressing this evolution in ENO's operations. However, with or without the FRP or similar mechanism, the PPCACR Rider would resolve any timing issues that may result in regulatory lag, ensure only the cost of the resource, including ENO's allowed return, is recovered from customers, and provides the Company and its stakeholders the assurances they need, *i.e.*, that full, incremental recovery will be accomplished on a timely basis, while at the same time avoiding the burden of costly pancaked and inefficient rate cases.

Q7. WHAT IS YOUR RESPONSE TO THE ADVISORS' POSITION REGARDING THE RECOVERY OF THE COSTS OF THE LTSA THAT ENO PROPOSES TO ENTER IF THE NOPS CT IS APPROVED?

A. As stated in the Direct Testimony of Company witness Mr. Todd, ENO requests authorization for the LTSA expenses that would be associated with the NOPS CT[2] to be recovered through the fuel adjustment clause ("FAC"). The LTSA is described by Company witness Robert A. Breedlove in his Direct Testimony. As Mr. Breedlove's testimony indicates, it is expected that the LTSA will specify a variable payment for the scope of covered maintenance, which payment would be determined based on a

[2] The Company does not anticipate entering into an LTSA if the Council approves the Alternative Peaker.

combination of the number of starts and the operating hours of the facility. Thus, the LTSA costs will be similar to fuel costs in that they are correlated with production and will be incurred only when the NOPS is actually operating. The LTSA may identify other work that the Company may request the Original Equipment Manufacturer to perform, *e.g.,* for extra work or unplanned maintenance above a cap, but the fees for any such work would be negotiated and agreed to in a separate work order. Mr. Breedlove further indicates that the term of the LTSA would be dependent on the actual operational dispatch of the unit. Because the major service provided under the LTSA will vary depending on production and operational dispatch of the unit, the character of these costs make them appropriate for recovery through the FAC.

Although Mr. Prep points to certain jurisdictions where LTSA expenses are subject to base rate treatment, it should be noted that certain jurisdictions permit recovery of LTSA through an FAC rider as ENO is proposing here. Of particular note, the Louisiana Public Service Commission has on several occasions authorized FAC recovery of LTSAs for Entergy Louisiana, LLC's combined cycle units, which LTSAs contain terms similar to that anticipated for the NOPS CT.[3]

[3] For example, see LPSC Order Nos. U-27836 (Perryville), U-30422-A (Ouachita), U-31966-C (Acadia), U-31971 (Ninemile 6), U-32759-A (Calcasieu) and U-35510 (Union).

Q8. PLEASE SUMMARIZE YOUR RESPONSE TO AIR PRODUCTS' AND THE JOINT INTERVENORS TESTIMONY REGARDING THE ABSENCE OF A SOLICITATION PROCESS IN THE SELECTION OF THE NOPS ALTERNATIVES.

A. ENO's review of the Council's rules and regulation have identified no requirements for a competitive selection process to determine how to fill identified resource needs for ENO. Neither Air Products nor the Joint Intervenors has presented evidence that suggests that a competitive solicitation process would have done anything more than add costs and delay in meeting ENO's needs and, as I explain later in my testimony, would have been a poor use of resources on behalf of ENO's customers.

III. CONTEMPORANEOUS RECOVERY OF NOPS' FIRST-YEAR REVENUE REQUIREMENT IS APPROPRIATE AND NECESSARY

Q9. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE COUNCIL ADVISORS' POSITIONS REGARDING ENO'S PROPOSED RATEMAKING TREATMENT FOR THE NOPS PROJECT.

A. As I appreciate the Direct Testimony of Mr. Prep, the Advisors agree "that 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."[4] However, the Advisors do not agree that, in the instance of the NOPS project, a contemporaneous exact cost recovery rider is the appropriate means by which to accomplish those objectives.

[4] *Id.*

Instead, Mr. Prep indicates that ENO's proposal to recover the NOPS non-fuel revenue requirement on an interim basis would constitute inappropriate, single issue ratemaking.[5]

Q10. DO YOU AGREE THAT ENO'S PROPOSED METHOD OF RECOVERING THE NON-FUEL REVENUE REQUIREMENT ASSOCIATED WITH NOPS WOULD BE SINGLE ISSUE RATEMAKING?

A. I do not. Mr. Prep has himself acknowledged that "ENO proposes that a NOPS exact cost recovery Rider would be an interim step, with realignment into the first FRP rate adjustment in 2020."[6] Although the timing of the rider's implementation would not be contemporaneous with the FRP adjustment in 2020, that 2020 FRP adjustment would take into account: the actual costs associated with the NOPS investment, all revenues assumed to be collected under the billed rider, a true-up of the difference between the projected and actual amounts, along with all other revenues received and expenses incurred by the Company in 2019. Similar to Ninemile 6 and Union Power Block 1, NOPS is a large investment that, without contemporaneous recovery, would put financial pressure on ENO. Contemporaneous recovery of this investment will provide ENO with financial flexibility and strength, which is important because it provides the capability to respond to unexpected needs or opportunities while

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5 *Id.*

6 *Id*. I have assumed that in this instance, Mr. Prep is referring to the Alternative Peaker proposal for NOPS, as the expected commercial operation date would be January 2020; whereas, the anticipated commercial operation date for the original peaker (CT) is estimated to be first quarter of 2021.

maintaining the ability to access capital through external financing sources both debt and equity, on reasonable terms. (The current version of the PPCACR Rider was approved by the Council in Resolution R-15-258, albeit on a non-precedential basis, has served as an appropriate mechanism to these policy objectives and, through its true-up mechanism, has ensured that customers pay only the costs incurred by ENO to receive the benefits of those resources.) From a ratemaking policy perspective, I do not believe that ENO's proposed recovery mechanism is the type that the Louisiana Supreme Court was concerned about in the case cited by Mr. Prep, *Entergy Louisiana, LLC v. La. Pub. Serv. Comm'n*, 990 So.2d 716, 727 (La. 2008). When the revenues and expenses of the capacity rider proposed by ENO are considered in the context of an FRP structure, as ENO has proposed, the FRP can be structured so as to account for all other revenues and expenses incurred by the Company in setting the appropriate level of rates.

Of course, because the modified PPCACR Rider could be implemented irrespective of the adoption of an FRP, it should be noted that regulatory bodies have accepted single issue ratemaking as a means to appropriately match costs and revenues and have accepted exact cost recovery mechanisms, especially for instances where the costs were large, volatile, or outside of the control of management. For example, fuel adjustment cost riders are predicated on single issue ratemaking and are an accepted cost recovery mechanism for most regulated utilities. Other examples of commonly accepted single issue cost recovery mechanisms include, storm damage riders (which are approved mechanisms in Arkansas, Mississippi, Texas, and

Louisiana), as well as additional capacity riders (which are approved in Arkansas, Mississippi, and Louisiana). These mechanisms have been approved by commissions as an efficient regulatory means to maintain the balance between customers and shareholders and recognize that utilities and their customers are faced with the changing economic and environmental conditions.

ENO's request to recover NOPS through a modified PPCACR Rider qualifies as a large cost that should be permitted single issue ratemaking treatment due to the difference in timing of ENO's planned Combined Rate Case and the COD of NOPS. Specifically, absent assurances to the contrary by the Council, ENO would not be afforded the opportunity to recover its NOPS revenue requirement through the Combined Rate Case and could suffer significant lag on recovery of the large investment, potentially affecting ENO's financial integrity.

Q11. MR. PREP CLAIMS THAT "[I]N DISCOVERY RESPONSES, ENO COULD ONLY PROVIDE GENERAL STATEMENTS WITHOUT ANY CREDIBLE FINANCIAL ANALYSIS TO SUPPORT ANY SHOWING OF FINANCIAL HARM IF [SIC] THEIR PROPOSED COST RECOVERY RIDER WAS NOT IMPLEMENTED." IS THIS CORRECT?

A. No, it's not. In ENO's response to Advisors' Data Request No. 10-20, which I have attached to my testimony here as Exhibit SLM-4, ENO provided the results of a hypothetical, high-level analysis that assumed a NOPS Alternative Peaker COD in January 2016 with no recovery of per book expenses, *i.e.* O&M, depreciation, and interest, for the first twelve months. The calculation demonstrates that if recovery of the NOPS Alternative Peaker revenue requirement were to be delayed for one year from the COD, ENO could be at risk of forever losing more than a quarter of its existing Net Income due to the added expenses associated with the plant without contemporaneous revenue to offset those costs. It should also be evident that without contemporaneous recovery, in addition to not being afforded an opportunity to recover the costs of operating the plant depicted in ENO's response to Advisors Data Request No. 10-20, ENO would have made the significant investment in NOPS without the opportunity to earn any equity return on that investment. Any delay in recovery undermines ENO's opportunity to recover its Council authorized return and very likely would negatively affect ENO's credit metrics, making it very challenging to attract capital on favorable terms. Further, the size of this investment exceeds ENO's annual operating cash flows[7], which further demonstrates that ENO cannot absorb the regulatory lag on an investment the size NOPS without access to capital markets.

Q12. YOU INDICATED THAT IT IS POSSIBLE TO STRUCTURE THE FRP SO AS TO AVOID SINGLE-ISSUE RATEMAKING CONCERNS OF IMPLEMENTING AN EXACT RECOVERY RIDER FOR NOPS REVENUE REQUIREMENTS. PLEASE SUMMARIZE HOW THIS MAY BE ACCOMPLISHED GIVEN ENO'S

[7] ENO's publicly available cash flow statement contained at page 399 of Entergy's 2016 Form 10-K reflects operating cash flow of $205 million in 2016, which included $86 million of non-recurring cash flows. Typical annual operating cash flows are approximately $100 million.

REQUEST TO RECOVER NOPS' FIRST-YEAR REVENUE REQUIREMENT OUTSIDE OF THE RETURN ON EQUITY ("ROE") BANDWIDTH ESTABLISHED UNDER THE TERMS OF THE FRP?

A. As suggested by Mr. Prep in his proposed recovery alternative for NOPS, an FRP could be structured to allow for forward-looking adjustments to capture known and measurable costs, such as large investments, that are anticipated to be placed in service at the time rates are implemented. An FRP that includes forward-looking adjustments appropriately matches costs with expected revenue recovery, reduces regulatory lag, and improves financial integrity of the utility through strengthened cash flows. Several of Entergy's operating companies include forward adjustments in their FRP's to capture the cost of large investment. For example, ELL's FRP includes an additional capacity mechanism, which allows ELL to adjust rates outside of their FRP bandwidth based upon the expected costs associated with new generation that will be placed in service at the time rates will be implemented. These costs are then rolled into the FRP bandwidth once a full year of actual costs and associated revenue recovery have been realized. Entergy Arkansas Inc.'s (EAI) FRP utilizes a forward test year, which is based upon projected costs and revenues which reduces regulatory lag for EAI. In addition, EAI has a capacity cost rider, which allows EAI to increase rates contemporaneously with the in-service date of new generation. Similarly, Entergy Mississippi, Inc. ("EMI") EMI's FRP includes known and measurable adjustments that are forward looking based upon the rate effective year, which allows EMI to pro-form in the expected costs for all investment that is expected to be placed in service during the rate effective year.

Q13. MR. PREP PROPOSES, AND MR. VUMBACO AGREES, THAT IF THE NOPS PROJECT IS SELECTED TO MEET ENO'S REQUIRED NEEDS, ENO SHOULD PRO-FORM THE COSTS INTO THE COMBINED BASE RATE CASE, WITH A TWO-STEP RATE IMPLEMENTATION TO CAPTURE THOSE COSTS TIMELY, ONE ON AUGUST OF 2019 FOR THE BASE RATE CASE AND A SECOND RATE CHANGE UPON THE COMMERCIAL OPERATION DATE OF THE UNITS. DO YOU AGREE WITH THIS PROPOSED RECOVERY APPROACH?

A. As stated earlier in my testimony, the Company believes that a modified exact cost recovery mechanism is reasonable and justified under the circumstances in this case. I agree, however, that Mr. Prep's proposed method could be reasonable if the alternative RICE units are selected as long as ENO is assured that the recovery of the NOPS revenue requirement will commence with the RICE units' COD; which is expected in January of 2020. Under ENO's interpretation of Mr. Prep's Direct Testimony, the first step in this process would be the implementation of rates resulting from the Combined Rate Case, which will be effective August of 2019. The second step of this process would increase rates to capture the costs of the RICE units beginning on its COD, which would appropriately match the cost of the units with its expected revenue recovery. As stated, ENO agrees that this cost recovery methodology could be a reasonable path forward, assuming this approach to recovery is approved by the Council.

On the other hand, with respect to the NOPS CT, it is reasonable to expect that the NOPS CT would not reach its COD until the first quarter of 2021. Under this timeline, it is unclear how the NOPS CT revenue requirement would be incorporated into the Combined Rate Case (in the absence of an FRP or decoupling mechanism). ENO believes this issue is not insurmountable and could be resolved through collaboration; and, the Company recognizes that the terms of an FRP or decoupling mechanism, including the pro-forma for the NOPS revenue requirement into such a mechanism, should be determined in connection with the Combined Rate Case.

In any case, in order to proceed with the investment required to construct NOPS, ENO should be provided reasonable assurances that such investment would be recovered on a timely/in-service basis. To this end, if ENO and the Council are unable to agree upon implementation of an FRP or decoupling mechanism that results in just and reasonable rates, then the implementation of a modified exact cost recovery rider could provide that assurance, while also ensuring that customers incur only the actual costs associated with the construction of NOPS contemporaneously with the receipt of benefits of NOPS, without the need for another costly rate case on the heels of the Combined Rate Case.

Q14. IN HIS DIRECT TESTIMONY, MR. PREP HAS OFFERED OPINIONS REGARDING THE PPCACR RIDER AND ITS ALLOCATION METHODOLOGY. HOW DO YOU RESPOND TO THOSE OPINIONS?

A. I recognize that Council Resolution R-15-542[8] approved, on an interim basis, ENO's contemporaneous recovery of certain non-fuel costs related to an existing power purchase agreement and the purchase of Union Power Block 1 through the PPCACR rider. I agree with Mr. Prep's statement that an in-depth examination of all applicable methodologies to allocate fixed costs should be completed for the Council's consideration in the Combined Rate Case,[9] including with respect to any riders that may be proposed. Such potential methodologies offered for Council consideration should be based on sound ratemaking principles.

Q15. MR. BRUBAKER CITES ISSUES WITH THE CURRENT PPCACR RIDER'S PER KWH COST APPORTIONMENT AMONG RATE CLASSES. IS THE COMPANY OPPOSED TO AN ALTERNATIVE APPROACH TO APPORTIONING COSTS AMONG RATE CLASSES FOR A RIDER TO RECOVER NOPS CAPACITY COSTS?

A. No. As described in the Direct Testimony and Supplemental Direct Testimony of Mr. Orlando Todd, the Company requests contemporaneous recovery through the PPCACR *or a modified version of that ride*r, as determined and approved by the

[8] Council Resolution R-15-542 dated November 19, 2015.

[9] Prep Direct, p. 7, ln. 3-4.

Council.[10] [Emphasis added.] Mr. Brubaker describes that in the absence of a class cost of service study, the appropriate approach to use for the PPCACR Rider would be to apply a uniform percentage factor to base rate revenues for all customer classes.[11] Mr. Brubaker asserts that "[t]his would essentially preserve existing rate relationship, and would be consistent with generally accepted cost of service principles."[12] If this Council determines that Mr. Brubaker's proposal is an appropriate alternative, the Company is not opposed to this approach to cost apportionment for NOPS and any additional capacity that may be procured by ENO to meet its supply-side resource requirements.

Q16. DO YOU AGREE WITH MR. BRUBAKER'S PROPOSAL THAT THE RECOVERY OF THE NOPS NON-FUEL REVENUE REQUIREMENT SHOULD BE DEFERRED UNTIL FOLLOWING A PRUDENCE REVIEW RATHER THAN COMMENCING IN-SERVICE INTERIM RECOVERY THROUGH A RIDER UPON COD?

A. No. The Company's proposal for contemporaneous recovery through the PPCACR Rider, or a modified version thereof, would eliminate lag on recovery of this investment, which is essential to the financial health of ENO, in addition to being a lower cost alternative to ENO's customers than deferring collection until the

10 Direct Testimony of Orlando Todd on behalf of Entergy New Orleans, Inc., Council Docket No. UD-16-02 (June 20, 2016), p. 8.

11 Additional Direct Testimony & Exhibits of Maurice Brubaker on behalf of Air Products and Chemicals, Inc., Council Docket No. UD-16-02 (October 16, 2017), p. 12.

12 *Id.*

prudence review is completed. Mr. Brubaker is proposing that ENO capitalize and defer the costs for NOPS until such time as the Council has completed its prudence review and considered all prudently incurred costs in connection with a subsequent rate case or FRP review. Mr. Brubaker has indicated that he expects that twelve months would be necessary for a decision to be rendered by the Council in a prudence review of NOPS, and during such time, ENO would be authorized to accrue carrying charges at the most recently determined weighted average cost of capital.[13] If Period II of the base rate case is pro-formed through the rate effective period, *i.e.*, 2019, and generally assumes the framework of ENO's past FRP, unless authorized by the Council, recovery of the NOPS Alternative Peaker could not commence before the rate change associated with test year 2021, *i.e.*, third quarter of 2021. A longer delay should be anticipated if an FRP is not in place and a traditional base rate case must be filed. Under either scenario, Mr. Brubaker's proposal would be more costly to customers due to the accumulation of carrying charges during the deferral period, in addition to the amortization of the deferred balance concurrent with recovery of the first-year revenue requirement.

IV. A FORMAL REQUEST FOR PROPOSALS WAS NOT NECESSARY TO IDENTIFY THE RESOURCE(S) BEST SUITED TO FILL ENO'S SUPPLY NEED

Q17. CERTAIN OF THE INTERVENORS' WITNESSES HAVE CRITICIZED ENO FOR NOT HAVING PERFORMED A FORMAL COMPETITIVE PROCESS TO

[13] See Exhibit SLM-3, Response of Air Products to ENO Data Request 1-7, Council Docket No. UD-16-02 (February 6, 2017).

SELECT A RESOURCE ADDITION FOR ENO.[14] IN YOUR OPINION, WAS IT NECESSARY TO DIRECTLY TEST THE REASONABLENESS OF NOPS TO FULFILL ENO'S RESOURCE NEED THROUGH A FORMAL COMPETITIVE SOLICITATION PROCESS/RFP?

A. No. As I appreciate the various testimonies of Company witnesses Jonathan E. Long, Seth E. Cureington and Charles W. Long, coupled with the Council's requirements, ENO's proposal to construct the NOPS alternatives represent a reasonable and cost-effective option to meet the needs of its customers. In other words, a costly, time-consuming RFP or other competitive solicitation process was unwarranted for several reasons.

First, the Council's rules and regulations do not require that an RFP be conducted prior to adding generating capacity intended to serve Council-jurisdictional customers. Second, as described in the Direct Testimony of Mr. Cureington, due to the retirement of Michoud Units 2 and 3, the termination of the Entergy System Agreement, and the Council's directive in Resolution R-15-524, it is clear that ENO has a specific need for incremental local peaking capacity in the City of New Orleans. With respect to the need to conduct a competitive all-source solicitation, as implied

[14] Direct Testimony & Exhibits of Maurice Brubaker on behalf of Air Products and Chemicals, Inc., Council Docket No. UD-16-02 dated January 6, 2017 ("Brubaker Direct", pp. 3-4; Pre-Filed Testimony of Elizabeth A. Stanton on behalf of Alliance for Affordable Energy, Deep South for Environmental Justice, 350 Louisiana – New Orleans, and Sierra Club, Council Docket No. U-16-02, dated October 16, 2017 ("Stanton Direct"), pp. 23-24; Pre-Filed Testimony of Philip Henderson on behalf of on behalf of Alliance for Affordable Energy, Deep South for Environmental Justice, 350 Louisiana – New Orleans, and Sierra Club, Council Docket No. U-16-02, dated October 16, 2017 ("Henderson Direct"), p.2.

by Joint Intervenor witnesses Mr. Philip Henderson and Dr. Elizabeth Stanton,[15] it is clear that such a process would have been useless to address ENO's need for peaking capacity, as this need cannot be met through demand-side management or intermittent supply side resources. As explained in the Direct and Supplemental and Amending Direct Testimony of Mr. Cureington and Mr. Charles Long, these alternatives are not suitable to fulfill ENO's reliability and local capacity needs and would very likely keep New Orleans customers exposed to cascading outages for an indefinite amount of time. Further, considering the need for incremental, local generation, it is very unlikely that a third party could build incremental generation to meet ENO's supply needs at a lower cost than NOPS.

It is also important to consider that such RFPs come at a considerable cost that would be ultimately borne by ENO's customers. Moreover, as stated above, the RFP could also add significant time delays, which could have further delayed realization of the reliability and economic benefits of the needed incremental generation.

Finally, as explained in the Direct Testimony and Supplemental and Amending Direct Testimony of Company witness Mr. Jonathan Long, the major cost component of ENO's proposed self-build, the contract for Engineering, Procurement and Construction ("EPC"), was tested through a competitive selection process.

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15 Henderson Direct at 10.

Q18. IS AN RFP FOR THE OVERALL RESOURCE NEED THE ONLY MEANS BY WHICH TO TEST THE REASONABLENESS OF THE COST TO BE INCURRED IN CONNECTION WITH A SELF-BUILD PROJECT?

A. No. Even Mr. Brubaker, in his Direct Testimony, characterizes an RFP as *an* accepted means – not *the only* accepted means – of testing the market to ensure that the best choice of new capacity is selected.

Q19. DO ALL RETAIL REGULATORS REQUIRE THAT AN RFP BE CONDUCTED AS PART OF THE CERTIFICATION PROCESS?

A. No. While I have not conducted a survey of the retail regulators that require an RFP that be conducted as part of the certification process, a review of the jurisdictions located in the Entergy Operating Companies' footprint reveals that no retail regulator aside from the LPSC has standing rules that require the utility to use an RFP process. It should be noted that the Council, in Docket No. UD-15-01 regarding the acquisition of the Union Power Station, approved that transaction despite the fact that it resulted from an unsolicited offer that was not subject to an RFP process. The Council was not alone in that regard, as both the Council[16] and the LPSC[17] determined that the Union Power Station acquisition was in the best interest of their customers without an RFP process.

16 Council Resolution R-15-542 (November 19, 2015).

17 LPSC Order U-33510 (November 5, 2015).

Q20. ARE THERE MATERIAL FACTORS ASSOCIATED WITH CONDUCTING AN RFP THAT SHOULD BE CONSIDERED WHEN DETERMINING WHETHER TO ISSUE AND RFP?

A. Yes. The Joint Intervenors' witness, Mr. Henderson, himself, recognizes in his Pre-Filed Direct Testimony that "there may also be legitimate reasons a utility or utility regulator might not use a competitive procurement process in certain instances."[18]

Q21. AT PAGE 7 OF HIS DIRECT TESTIMONY, MR. BRUBAKER CRITICIZES ENO FOR NOT MAKING ANY EFFORT TO DETERMINE A PURCHASED POWER AGREEMENT ("PPA") WITH THIRD PARTIES WERE AVAILABLE. IS MR. BRUBAKER'S CRITICISM OF ENO'S PROCESS APPROPRIATE?

A. No. As I understand from the Direct Testimony and Supplemental and Amending Direct Testimony of Messrs. Cureington and Long in this proceeding, there are presently no local generating resources, *i.e.*, within the City of New Orleans, which is where a resource is needed for reliability.

Q22. COULD ENO REALIZE AN INCREASED COST OF CAPITAL ASSOCIATED WITH A PPA?

A. Yes. ENO works to maintain a credit rating that supports a reasonable total cost of capital for customers, while providing the financial stability and flexibility for the Company to support the safe and reliable operation of its business. The Company's

[18] Henderson Direct at 10.

credit ratings, and the cost of debt, reflect this balance. Credit ratings agencies, like Standard & Poor's ("S&P"), impute additional debt to the Company for PPAs, on a risk adjusted basis. Although the Company currently enjoys a BBB+ corporate credit rating from "S&P" and a Ba1 rating from Moody's Investors Services, there is a risk that adding PPA transactions to the PPAs currently in ENO's portfolio may affect the Company's credit ratings to the extent that the imputation of debt becomes a more significant factor in the Company's credit profile, or S&P determines that there are additional risks to the recovery of amounts under the a PPA or similar transactions. This imputation may cause the Company to have to take action – and to incur costs – to maintain its investment grade credit rating and to avoid a variety of potential increased costs to customers that would result from a sub-investment grade credit downgrade, such as increased borrowing costs and increased costs of capital.

Q23. HAS ENO UNDERTAKEN EFFORTS TO DEMONSTRATE THAT NOPS IS THE LOWEST REASONABLE COST ALTERNATIVE TO RELIABLY SERVE ENO?

A. Yes. As explained in the Direct Testimony of Mr. Cureington, the 2015 Integrated Resource Plan portfolio included a robust process that identified a Combustion Turbine as the lowest reasonable cost resource addition (considering the risks) capable of meeting the Company's overall capacity needs. Mr. Cureington also explains in his Direct Testimony, Supplemental Direct Testimony, and Supplemental and Amending Testimony, that the Company performed several iterations of economic analyses associated with the CT, and it proved be the lowest cost alternative in each .

Moreover, ENO engaged in a competitive selection process to confirm that the EPC contract, which accounts for roughly 70% of the overall cost of the self-build, was competitive. As explained in the Direct Testimony of Company witness Mr. Jonathan Long, four potential contractors participated in the competitive selection process conducted by ENO. The results of that process ultimately validated that the EPC pricing offered by CB&I was competitive within the current market for such services, as CB&I's price was the lowest bid.

With respect to the RICE units, Mr. Jonathan Long explains in his Supplemental and Amending Direct Testimony that the Company engaged Worley Parsons to conduct a technology assessment, and that the RICE units were selected due the fact that they the lowest levelized cost of electricity, as well as other important considerations such as black-start capability, a low heat rate, extremely low ground water use, *etc*.

Once the technology was selected, the Company then engaged conducted another competitive process and selected Burns & McDonnel as the EPC contractor due to its competitive pricing and significant experience with constructing RICE projects in the United States, with two additional projects under construction to be completed in 2018. Mr. Cureington explains that it is a reasonable alternative to the CT and is a virtual tie from a total supply cost perspective with all other cases analyzed.

Thus, as described by these witnesses, the Company went through a reasonable process to ensure the selection of either NOPS Alternative would serve the public interest.

Q24. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SHAUNA LOVORN-MARRIAGE**, who after being duly sworn by me, did depose and say:

That the above and 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.

Shauna Lovorn-Marriage

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 28th DAY OF NOVEMBER, 2017

NOTARY PUBLIC

My commission expires: at death

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

ENTERGY NEW ORLEANS, INC.
CITY OF NEW ORLEANS
Docket No. UD-16-02

Response of: Entergy New Orleans, Inc.
to the First Set of Data Requests
of Requesting Party: Advisors to the Council
of the City of New Orleans

Question No.: Advisors 10-20 Part No.: Addendum:

Question:

Please refer to the Advisors' DR CNO 9-1. Please also refer the Advisors' DR CNO 7-2 and ENO's response thereto which states in part, "Not having timely recovery for a project of this size creates significant financial risk for ENO" and "contemporaneous recovery outside of the bandwidth formula reduces financial risk for ENO."

a. Provide copies of all documents and analysis supportive of the first referenced statement, identifying in particular the calendar duration defining "timely recovery" and the quantification of "significant financial risk for ENO."

b. Provide copies of all documents and analysis supportive of the second referenced statement.

i. If no analysis is available to support the statement, provide a detailed explanation of how cost recovery through the bandwidth formula would increase the financial risk for ENO, using the bandwidth formula of the last FRP to illustrate.

Response:

a. As stated on pages 7-8 of Mr. Todd's Supplemental and Amending Direct Testimony, the Company has assumed that, if the Council does not permit contemporaneous recovery, then ENO is at risk of not recovering the alternative peaker's annual revenue requirement for approximately one year. If that occurs, ENO estimates that its Net Income could be reduced by more than 25% over one year, which would affect ENO's financial condition adversely. See the attached.

b. See the response to subpart (a) above.

Question No.: Advisors 10-20

i. The Company does not know the terms of the FRP and its bandwidth formula that may be approved in the 2018 Combined Rate Case. For example, the bandwidth formula may not permit an ROE Adjustment to the Evaluation Period Cost Rate for Common Equity.

The Company's response to Advisors 7-2 should be understood to mean that the Company's position is that, if the alternative peaker's annual revenue requirement based on a historical twelve-month period is incorporated into rates through an FRP Rate Adjustment, then such FRP Rate Adjustment should reflect the entirety of the annual revenue requirement and not less due to the mechanics of any FRP bandwidth formula. For example, assume ENO's Evaluation Report excluding the alternative peaker's annual revenue requirement shows that ENO is earning its Evaluation Period Cost Rate for Common Equity. If the alternative peaker's annual revenue requirement is then taken into consideration, then the FRP Rate Adjustment should reflect the entirety of the alternative peaker's annual revenue requirement so that ENO continues to earn its Evaluation Period Cost Rate for Common Equity assuming all else being equal.

Attachment to the Company's Response to Advisors 10-20

Net Income Effect from Alternative Peaker

Operating Expenses		6,655,000
Depreciation and Amortization		6,993,000
Interest Expense		
Rate Base	179,272,000	
Weighted Debt Cost	2.34%	
		4,194,965
Total Expenses		17,842,965
Tax Expense		(6,865,973)
Earnings Effect		(10,976,992)
Assumed Net Income		43,676,228
Percent Change in Net Income		-25.13%

Assumed Net Income Based on Per Book Capitalization as of December 31, 2016

Total Capitalization	786,959,069
Equity Ratio	50.00%
Assumed Common Equity	393,479,534
ROE	11.10%
Assumed Net Income	43,676,228

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY FILING	)	**DOCKET NO. UD-16-02**

RESPONSE OF AIR PRODUCTS AND CHEMICALS, INC. TO THE
FIRST REQUEST FOR INFORMATION OF ENTERGY NEW ORLEANS, INC.

ENO 1-7:

On page 4 of his Direct Testimony in this proceeding, Mr. Brubaker finds "that ENO does not need to have an exact cost recovery rider of any kind. Rather, it can capitalize and defer for later recovery (after the conclusion of a prudence review) the non-fuel costs associated with any new unit, should it be approved by the Council."

a. Under Mr. Brubaker's alternative proposal, would ENO be authorized to defer with carrying costs the non-fuel costs associated with any unit? If the answer is yes, please state the terms upon which such carrying costs would accrue?

b. What is Mr. Brubaker's expectation of the amount oftime that it would be necessary for a decision to be rendered by the Council in a prudence review of any new unit constructed by the Company?

RESPONSE:

a. During the prudence review, and until there is a subsequent rate case to consider adjusting rates to reflect the cost of NOPS, ENO would be allowed to defer the non-fuel revenue requirement associated with NOPS. The carrying charge rate would be equal to ENO's most recently determined cost of capital.

b. Twelve months.

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	))))))	**DOCKET NO. UD-16-02**

REBUTTAL TESTIMONY

OF

DR. GEORGE LOSONSKY, PH.D., P.G.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

NOVEMBER 2017

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Dr. George Losonsky, Ph.D., P.G. I am the President of Losonsky & Associates, Inc. of 4207 Rhoda Drive, Baton Rouge, Louisiana 70816.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company") in support of the Company's Supplemental and Amending Application for Approval to Construct the New Orleans Power Station ("NOPS") and Request for Cost Recovery and Timely Relief ("Supplemental Application").

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted Supplemental and Amending Direct Testimony ("Direct Testimony"), which ENO filed on July 6, 2017. The educational and professional credentials and experience that qualify me to provide my expert opinions on issues related to subsidence, differential settlement, flood protection, and hydrogeology are described in that Direct Testimony.

Q4. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my Rebuttal Testimony, I address and refute the conclusions and underlying statements advanced in the October 13, 2017 testimony of Dr. Alexander Kolker, Ph.D. Specifically, I address the "technical concerns" Dr. Kolker raised with regard to the conclusions summarized in my Direct Testimony and substantiated in the C-K

Technical Report (Exhibit JEL-6), the Addendum to the C-K Technical Report (Exhibit GL-2) and the CB&I Report (Exhibit GL-3). I also discuss the reasons why Dr. Kolker's recommendation – that the Council for the City of New Orleans (the "Council") should hire additional third parties to conduct additional analyses of risks associated with groundwater usage occasioned by the operation of the Combustion Turbine ("CT"), initially proposed in the Application filed on June 20, 2016, and the seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker") that ENO's Supplemental Application proposes as an alternative to the CT, prior to approving the construction of either unit – is unfounded.

In addition to refuting the points raised in Dr. Kolker's October 2017 Testimony, I also briefly discuss the numerous points raised in my Direct Testimony and supporting analyses that Dr. Kolker fails to address, and with which he presumably agrees, or is not able to refute, given that he did not counter them in his sworn testimony. I also remind the Council of the scientific and mathematical analyses that support my conclusions that groundwater withdrawal associated with the CT or the Alternative Peaker will not increase or contribute to subsidence or cause damage to infrastructure in New Orleans East. Other than referring to these analyses in passing, Dr. Kolker's testimony does not contest the correctness of my calculations nor does he contest that these calculations and associated analyses constitute widely-accepted and fully-appropriate methods for conducting an industry-standard, independent evaluation of possible risks associated with groundwater usage.

II. REVIEW OF THE PRIOR TESTIMONIES

Q5. IN HIS OCTOBER 2017 TESTIMONY, DR. KOLKER INDICATES THAT YOUR DIRECT TESTIMONY DID NOT CONTAIN "SPECIFIC CRITICISMS" OF HIS JANUARY 2017 TESTIMONY. IS THIS A TRUE STATEMENT?

A. No. Dr. Kolker does not accurately represent the contents of my Direct Testimony in his statement to the Council. My Direct Testimony, at pages 19 through 29, contains many specific criticisms of Dr. Kolker's January 2017 Testimony. These specific criticisms included (i) Dr. Kolker's failure to provide "any analysis of the water levels in the Gonzales-New Orleans aquifer,"[1] (ii) the lack of any analysis of "drawdown levels, or consolidation calculations associated with the proposed operation of NOPS," which I noted was, at minimum, "necessary to substantiate any opinion concerning the possible effects of groundwater withdrawal from a generator,"[2] (iii) Dr. Kolker's misunderstanding of the critical difference between subsidence and differential settlement in his Testimony, which I stated resulted in his failure to "identify or analyze the actual cause of damage to buildings and infrastructure in New Orleans East,"[3] (iv) Dr. Kolker's discussion of issues not relevant to assessing the subsidence risks specific to NOPS, which "suggests that Dr. Kolker's analysis is unfocussed and to a large extent irrelevant,"[4] and (v) that Dr. Kolker "lacks the background in groundwater wells and subsurface geology to assess the effects of operating NOPS on subsidence or the specific causes of damage to buildings and infrastructure observed

[1] *See* Supplemental and Amending Direct Testimony of Dr. George Losonsky, Ph.D. ("Losonsky Direct") at pg. 19, lns. 15-16.
[2] *Id.,* pg. 19, lns. 17-20.
[3] *Id.*, pg. 20, lns. 16-19.
[4] *Id.*, pg. 22, lns. 6-8.

in New Orleans East [and that] [h]e also does not seem to have any background specifically related to southeast Louisiana flood protection infrastructure."[5]

Q6. DID DR. KOLKER'S OCTOBER 2017 TESTIMONY ATTEMPT TO REMEDY ANY OF THESE DEFICIENCIES?

A. No. Dr. Kolker's October 2017 Testimony fails to acknowledge my extensive discussion of the flaws with his January 2017 Testimony, much less attempt to remedy them.

Q7. WHAT EFFECT DOES DR. KOLKER'S FAILURE TO ACKNOWLEDGE OR ADDRESS THE PREVIOUSLY IDENTIFIED FLAWS WITH HIS JANUARY 2017 TESTIMONY HAVE ON THE INTEGRITY OF HIS OCTOBER 2017 TESTIMONY?

A. Dr. Kolker's failure to address the analytical flaws I previously identified has resulted in his October 2017 Testimony repeating many of the errors made in his January 2017 Testimony. Dr. Kolker again failed to account for the difference between subsidence and differential settlement; he again failed to conduct any analysis of the water levels in the Gonzales-New Orleans aquifer; he again failed to conduct any drawdown or consolidation calculations or even comment upon the accuracy of my calculations in this regard. As a result, Dr. Kolker's October 2017 Testimony again fails to present opinions supported by even the bare minimum of scientific analysis that would be

[5] *Id*., pg. 22, lns. 18-22.

necessary to justify his recommendations to the Council.

III. CALCULATIONS PERFORMED TO QUANTIFY POTENTIAL EFFECTS OF NOPS ON SUBSIDENCE

Q8. YOU NOTED ABOVE THAT YOU PERFORMED SPECIFIC MATHEMATICAL CALCULATIONS THAT ARE PART OF AN INDUSTRY-STANDARD METHOD FOR INDEPENDENTLY ANALYZING POSSIBLE EFFECTS OF GROUNDWATER USAGE. PLEASE REMIND THE COUNCIL OF WHAT THESE CALCULATIONS WERE AND WHAT YOU CONCLUDED BASED UPON THEM?

A. In the Addendum to C-K & Associates' Technical Report of November 16, 2016, I presented calculations of drawdown using several standard solutions: The Theis solution, the Cooper-Jacob Solution, and the Hantush and Jacob Leaky Aquifer Solution. These solutions were applied over a 10-year period, which yielded highly conservative drawdown calculations. The Hantush and Jacob Leaky Aquifer Solution is the most accurate solution for the New Orleans-Gonzalez aquifer because it includes the effect of overlying formations. The drawdown calculations predict approximately 0.8 to 1.2 foot of drawdown within 100 feet of the well, 0.6 to 1.0 foot 250 feet away, and less than 0.02 to 0.27 foot 10,000 feet away from the well if it is pumping 96 gallons per minute ("gpm"). The drawdown calculations predict approximately 0.03 to 0.05 foot of drawdown within 100 feet of the well, 0.02 to 0.04 foot 250 feet away, and 0.01 foot or less 10,000 feet away from the well if it is pumping 3.9 gpm. The Addendum also calculates consolidation settlement using a published solution by Niu, *et al.*, which is based on standard geotechnical principles and derived for a groundwater withdrawal well in the same hydrogeological setting as the groundwater recovery wells at NOPS. The model predicts consolidation settlement of 0.04 inch or less if the flow rate is 96 gpm, and it predicts consolidation settlement of less than 0.002 inch if the flow rate is 3.9 gpm. As noted in my Direct Testimony, this consolidation settlement is predicted to occur 500-650 feet below the surface of the earth. Based on the results of these calculations, I stated in sworn testimony to the Council that it is my independent, professional opinion that neither the CT unit nor the Alternative Peaker will increase or contribute to subsidence in New Orleans East or the New Orleans Metro area.

Q9. DID DR. KOLKER ADDRESS THE MERITS OF YOUR USE OF THESE METHODS TO SUPPORT YOUR CONCLUSION THAT NEITHER UNIT WOULD CREATE ADDITIONAL SUBSIDENCE-RELATED RISKS FOR NEW ORLEANS?

A. Dr. Kolker did not challenge the accuracy or correctness of my calculations, nor did he dispute that the methods I utilized constitute an industry-standard and scientifically-accepted way to neutrally and independently evaluate and predict the potential impacts of groundwater usage on subsidence. Dr. Kolker's singular, passing reference to the calculations I performed criticizes the calculations in a limited and superficial manner, which I will rebut in detail.

Q10. WHAT CRITICISM DID DR. KOLKER STATE WITH REGARD TO YOUR PRIOR CALCULATIONS?

A. The only specific criticism Dr. Kolker makes regarding the calculations I performed to validate my independent, professional opinion that NOPS will not exacerbate subsidence in New Orleans is to express concern that "the modeling was conducted only for a 10-year period." Dr. Kolker's opinion, though he cites no studies, articles, findings, or basis to support the opinion, is that "the modeling should be conducted for the entire expected life of the plant, plus an additional factor of safety time frame." Dr. Kolker fails to quantify the specific "safety time frame" he discusses, nor does he cite any source that purports to offer such a quantification.

Q11. DO YOU BELIEVE DR. KOLKER'S CRITICISM IN THIS REGARD TO BE VALID?

A. No. As explained in my Direct Testimony, the C-K Technical Report, and the Addendum to the C-K Technical Report, the 10-year timeframe used in my calculations is a standard, maximum timeframe for estimating long-term, steady-state drawdown caused by groundwater withdrawal. An aquifer will reach steady-state drawdown long before 10 years have elapsed, so that the 10-year calculation is guaranteed to over-estimate drawdown. Extending the drawdown solution to 10 years yields highly conservative results and no scientific basis exists for extending the solution beyond 10 years. By applying the 10-year drawdown calculation to the consolidation model, the consolidation model represents maximum consolidation over the expected 50-year life of NOPS.

To illustrate this point, I have provided **Figure 1** below, which shows predicted drawdown in 10 years, 30 years, and 50 years assuming continuous pumping at 3.9 gpm, which correlates to the Alternative Peaker, for both the high-end and low-end vertical hydraulic conductivity conditions in the overlying aquitard.

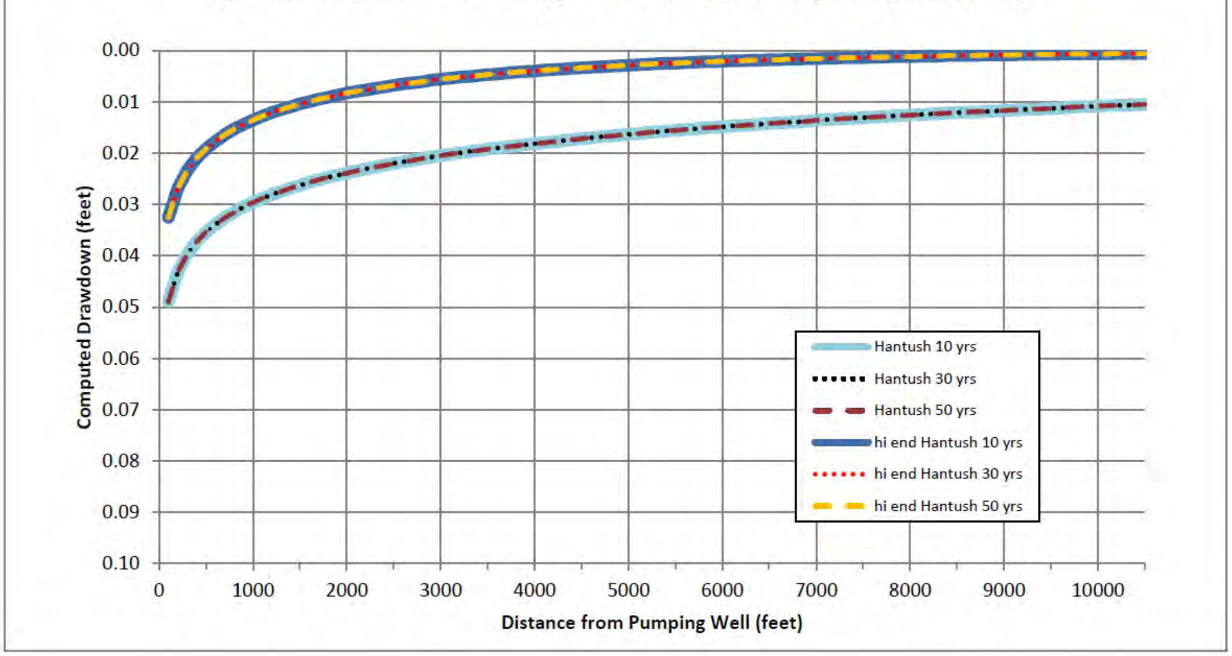
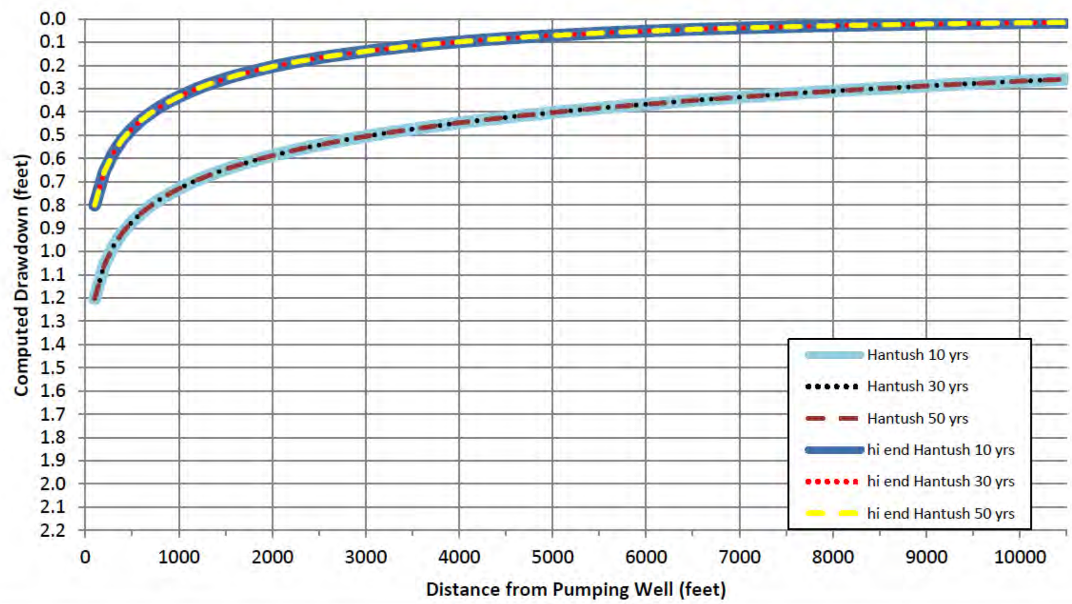


Figure 1. Drawdown for 3.9 gpm at 10, 30, and 50 years (linear plot)

I have also provided **Figure 2** below, which shows predicted drawdown in 10, 30 and 50 years assuming continuous pumping at 96 gpm, which correlates to the CT unit, for both vertical hydraulic conductivity conditions.

Figure 2. Drawdown for 96 gpm at 10, 30, and 50 years (linear plot)



In each of the two figures both sets of three graphs representing 10, 30, and 50 years are essentially superimposed, indicating that steady-state flow has been achieved early, before 10 years have elapsed, and drawdown remains steady over the projected 50-year period of operation of NOPS.

Q12. DOES DR. KOLKER MAKE ANY OTHER STATEMENTS RELATED TO THE EXPECTED CONSOLIDATION OR DRAWDOWN POTENTIALLY ASSOCIATED WITH THE OPERATION OF NOPS?

A. Yes. Dr. Kolker states that the CT unit could possibly operate 365 days per year and provides a simple multiplication equation for estimating the total amount of water withdrawn over 10-year and 50-year periods. He then states that "the question of what happens to the void space left behind after this water is withdrawn remains unanswered."

Q13. DO DR. KOLKER'S STATEMENTS IN THIS REGARD EXPRESS SCIENTIFICALLY VALID CONCERNS?

A. No. There are a number of problems with Dr. Kolker's statements. First, as I noted above, Dr. Kolker failed to conduct any analysis specific to the water levels in the Gonzales-New Orleans aquifer. His inaccurate and baseless statement regarding the "void space left" following water withdrawal evidences the importance of understanding aquifer hydraulics, as well as analyzing water levels and trends in the specific aquifer from which water is being withdrawn, when attempting to assess potential impacts of that withdrawal. While a calculation of the number of swimming pools equivalent to the volume of water withdrawn over time may seem, perhaps by design, shocking, it is irrelevant to subsidence because it omits consideration of four critical aspects of aquifer hydraulics during groundwater withdrawal. First, during most of the 10-year or 50-year withdrawal periods Dr. Kolker seeks to analyze, groundwater withdrawal will proceed under steady-state conditions, during which no new void spaces are created because the withdrawn groundwater is continuously replenished in the aquifer through its natural sources of recharge and normal groundwater migration. Second, his void space calculations incorrectly assume that aquifer yield is the same as void space. Third, most of the void space created by drawdown forms in the very early stage of pumping. My calculations address the effects of any potential void space possibly created by the proposed groundwater withdrawal and show that it will not contribute to subsidence in New Orleans East or in the greater New Orleans area. Fourth, as noted in my Direct Testimony and as substantiated in the C-K Technical Report and the Addendum to the C-K Technical Report, water levels in the Gonzales-New Orleans aquifer have been rising for over 40 years. Moreover, the calculations I performed specific to the aquifer demonstrate that neither unit will pump groundwater at a rate required to counteract this replenishment. Thus, the "question of what happens to the void space left" that Dr. Kolker presents has been answered by my prior analyses. The answer is that no "void space" will be created in the first place, and my calculations provide a mathematically and scientifically sound basis for this conclusion. Dr. Kolker's concerns seem to only be supported by unscientific speculation, not industry-accepted calculations.

I will also note, as I stated in my Direct Testimony, that my calculations assumed the units would operate 365 days per year, 24 hours per day, despite the fact that this level of operation will not be permitted or possible. As such, Dr. Kolker's statement concerning the possibility of the plant operating 365 days per year, while inaccurate, does not impact the validity of my analyses in the least.

Q14. DR. KOLKER ALSO OPINES THAT THE REDUCED GROUNDWATER USAGE ASSOCIATED WITH NOPS DOES NOT NECESSARILY MEAN THAT THERE WILL BE NO SUBSIDENCE ASSOCIATED WITH NOPS. HOW WOULD YOU ADDRESS THIS CONCERN?

A. I would, and have, addressed this concern by performing the calculations I described herein and which are fully documented in the C-K Technical Report and the Addendum to the C-K Technical Report. As I have discussed at length, these calculations eliminate the need to speculate as to possible subsidence associated with NOPS because they provide a conservative estimate of the worst-case scenario quantification of the possible subsidence impacts. The calculations, which have not been refuted or disputed, support my conclusion that neither unit will add to subsidence in the region.

Q15. DR. KOLKER ALSO STATES THAT DATA FROM PRIOR US GEOLOGICAL SERVICE SURVEYS INDICATE THAT "REDUCTIONS IN GROUNDWATER USAGE ARE CAUSING THE WATER TABLE TO REBOUND OVER A PERIOD OF SEVERAL DECADES" IS THIS AN ACCURATE STATEMENT?

A. No. Regional water table rebound of the kind observed in the New Orleans-Gonzalez is caused by a combination of processes, which are not exclusively tied to groundwater usage. The aquifer in the vicinity of a pumping well is replenished by water from other parts of the aquifer, extending over a large portion of southeast Louisiana. The main source of water entering the aquifer, called recharge, is north of the greater New Orleans area, in Livingston and Tangipahoa Parishes. A general pattern in Louisiana of increased annual rainfall rates has the general effect of increasing recharge, which leads to rising water levels. The New Orleans-Gonzalez aquifer is also recharged by leakage from overlying and potentially from underlying aquifers.

Dr. Kolker's comparison of the proposed groundwater withdrawal at NOPS to driving an automobile, where operation at any speed continues to propel the vehicle forward, is incomplete and therefore misleading for three reasons. First, a minimum threshold of operation must be exceeded before subsidence can result. Potential water level decline that is equaled or exceeded, and thus negated, by natural water level increase or within the range of natural water level fluctuations cannot affect subsidence. This is analogous to an automobile idling at a stop light on an incline. The engine must run but the vehicle does not move forward. Second, a minuscule amount of compaction in the aquifer at 650 foot depth will not be expressed at the ground surface because it will dissipate across the overlying mass of rock and sediment, and because it will be cancelled out by other natural, ongoing tectonic and geotechnical processes. This is analogous to the fact that while the pistons of the engine may be moving as it is idling at the hilltop stoplight, the wheels are not turning. Perhaps a better analogy is hair loss. A healthy scalp sheds a normal number of hair follicles daily, which it regenerates. While combing or brushing removes hair, it does not cause hair loss. Third, there are geotectonic reasons for subsidence related to post-glacial crustal processes which are ongoing in southern Louisiana. Again, Dr. Kolker's lack of understanding or analysis of the attributes specific to the Gonzales-New Orleans aquifer, as further evidenced by his misplaced automobile analogy, demonstrates that his testimony fails to provide the bare minimum level of support for a professionally substantiated opinion on subsidence risks.

IV. ANALYSIS OF GROUNDWATER USAGE IMPACTS FOR DEACTIVATED MICHOUD PLANT

Q16. DR. KOLKER DISAGREES WITH YOUR ASSESSMENT OF THE ABSENCE OF EVIDENCE OF DIFFERENTIAL SETTLEMENT AT THE SITE OF THE DEACTIVATED MICHOUD PLANT. HOW WOULD YOU RESPOND TO DR. KOLKER'S STATEMENTS?

A. Once again, Dr. Kolker's Testimony evidences a lack of understanding between subsidence and differential settlement. This lack of understanding was one of the "specific criticisms" of his January 2017 Testimony that I described in detail in my Direct Testimony and which Dr. Kolker made no attempt to refute or remedy in his October 2017 Testimony. Dr. Kolker continues to confuse the issue, to the detriment of the integrity of his opinions.

Q17. PLEASE EXPLAIN HOW DR. KOLKER'S LACK OF UNDERSTANDING OF THIS DISTINCTION IS EVIDENCED IN HIS DISCUSSION OF YOUR ANALYSIS OF DIFFERENTIAL SETTLEMENT.

A. The only context in which Dr. Kolker mentions differential settlement is a partial quote from my Direct Testimony.[6] Based on this incomplete recitation of my Testimony, Dr. Kolker then criticizes the accuracy of my conclusions concerning the absence of *differential settlement* at the Michoud site by stating that I did not measure *subsidence* at two different points in time. This false equivalency evidences a fundamental misunderstanding of the distinction between subsidence and differential

[6] *See*, October 13, 2017 Kolker Supplemental Direct at pg. 4, Q. 8.

settlement. It also results in Dr. Kolker including an unfounded and inapplicable criticism of my analysis in his Testimony.

As I explained in my Direct Testimony, and as the C-K Technical Report discusses in great detail, subsidence is properly thought of as a cause and differential settlement as a potential effect. Differential settlement, not subsidence, is what causes damage to property, buildings, and other infrastructure. Groundwater withdrawal done in an improperly managed manner can cause differential settlement. In the portion of my Direct Testimony immediately prior to the partial quote Dr. Kolker discusses, I stated that "where groundwater withdrawal does cause differential settlement, signs of differential settlement (such as damage to buildings and other infrastructure) would be visible at or near the wells themselves."[7]

The portion of my Direct Testimony from which Dr. Kolker selectively quotes concerns the methods through which I analyzed the possibility of *differential settlement* occurring at the Michoud site, not through which I attempted to quantify *subsidence* occurring in that area. Consequently, Dr. Kolker's claim that the methods I described were not adequate for measuring *subsidence* fails to refute or even consider the adequacy of those methods for evaluating *differential settlement*. I affirmatively stated in my Direct Testimony that I did not contend that subsidence had not occurred in New Orleans East or near the Michoud wells.[8] Instead, my analysis documented the absence of *differential settlement* at the Michoud site in order to demonstrate that the groundwater usage associated with the deactivated plant did not

[7] Losonsky Direct at pg. 9, Q. 13.
[8] *See* Losonsky Direct Testimony at pg. 10, lns. 10-13.

cause damage to property and infrastructure in New Orleans East because it did not cause such damage at the well site. Dr. Kolker's criticism of this analysis misses the mark entirely because he does not acknowledge or understand the critical difference between subsidence and differential settlement.

V. ANALYSIS OF FLOOD-RELATED RISKS

Q18. DR. KOLKER MENTIONS CONCERNS ABOUT THE POSSIBILITY OF SUBSIDENCE AFFECTING THE INTEGRITY OF THE HURRICANE AND STORM DAMAGE RISK REDUCTION SYSTEM ("HSDRRS") THAT YOU DISCUSSED EXTENSIVELY IN YOUR DIRECT TESTIMONY. DO YOU SHARE DR. KOLKER'S CONCERNS?

A. No. The calculations I have performed, the accuracy of which has not been disputed, demonstrate that neither unit will add to subsidence in the region. Therefore, even if subsidence could pose a threat to the HSDRRS, my unrefuted analyses demonstrate that NOPS will not contribute to such subsidence.

More importantly, as I noted in my Direct Testimony, through my service as a Commissioner on the South Louisiana Flood Protection Authority – East ("SLFPA-E"), I have extensive, first-hand knowledge of the development, design, and construction of the HSDRRS. Through that experience, I thoroughly investigated and evaluated the resilience of the HSDRRS and the robustness of its design. This led me to conclude, as I previously testified, that the United States Army Corps of Engineers and the Coastal Protection and Restoration Authority ("CPRA") took the effects of subsidence and sea-level rise into account when designing the HSDRRS and designed that system to be resilient to such effects. As such, I believe Dr. Kolker's concerns to be invalid, on the basis of both my hydrogeological analyses and my involvement in the design and building of the HSDRRS.

Q19. IN YOUR DIRECT TESTIMONY, YOU DEVOTED SIGNIFICANT DISCUSSION TO BOTH YOUR EXPERIENCE AS AN SLFPA-E COMMISSIONER AND TO INVALIDATING DR. KOLKER'S CONCERNS REGARDING FLOOD RISKS AT THE PROPOSED NOPS SITE. HAS DR. KOLKER'S MOST RECENT TESTIMONY ADDRESSED THESE ISSUES?

A. No. Dr. Kolker's most recent testimony fails to address the flaws and errors I pointed out in his prior testimony regarding his opinions about flood risks at the proposed NOPS site and the reasons he identified in an attempt to validate his opinions. One of the many facts cited in my Direct Testimony that Dr. Kolker fails to address is that the CPRA's 2017 Master Plan predicts no flooding at the proposed NOPS site under the worst-case storm scenario considered under the Master Plan (the "high scenario" over a 50-year time frame). This finding by the CPRA results from many factors, including the components of the HSDRRS infrastructure that surround the NOPS site and mitigate each factor that contributed to overtopping of the levees at the site of the deactivated Michoud plant during Hurricane Katrina.[9] These measures and their geographic relationship to the proposed NOPS site are depicted in **Figure 3**, below.

[9] The Supplemental Direct Testimony of Jonathan E. Long, at pgs.19-20, provides more specific details on the causes of the overtopping of levees at the Michoud site during Hurricane Katrina and how the HSDRRS mitigates each one of those contributing factors.

Q20. ARE THE HSDRRS MEASURES DEPICTED ABOVE THE ONLY MEASURES THAT HAVE ELIMINATED THE RISK OF FLOOD DAMAGE FOR THE PROPOSED NOPS SITE?

A. No. As I described in my Direct Testimony, and as the Supplemental Direct Testimony of Mr. Jonathan E. Long described in greater detail, the proposed top of concrete for the proposed NOPS facility is 1 foot higher than the observed Hurricane Katrina flooding and 2.5 feet higher than the recommended FEMA flooding elevation. Dr. Kolker failed to take these facts into account in his January 2017 Testimony and his October 2017 Testimony does not address the issue of flood risks at the NOPS site.

Q21. DO YOU, AS A FORMER COMMISSIONER OF THE SLFPA-E, BELIEVE THE COUNCIL SHOULD BE CONCERNED WITH A RISK OF FLOODING AT THE PROPOSED NOPS SITE WHEN DECIDING THE MERITS OF ENO'S SUPPLEMENTAL APPLICATION?

A. No, I do not.

Q22. DO YOU, AS A FORMER COMMISSIONER OF THE SLFPA-E, BELIEVE THAT SITING AND OPERATING NOPS AS ENO PROPOSES IN ITS SUPPLEMENTAL APPLICATION WOULD CREATE ANY RISK OF DAMAGE TO FLOOD PROTECTION INFRASTRUCTURE?

A. No, I do not. Furthermore, my analyses and calculations provide ample support for my independent, professional opinion that the proposed construction and operation of either the CT unit or the Alternative Peaker poses no risk to the integrity of the HSDRRS flood protection components, or any other infrastructure in New Orleans East or the New Orleans Metro area.

VI. NO NEED FOR ADDITIONAL EVALUATIONS HAS BEEN SHOWN

Q23. DR. KOLKER REPEATEDLY RECOMMENDS THAT THE COUNCIL ENGAGE ANOTHER INDEPENDENT EXPERT, BESIDES YOU, TO PERFORM AN ADDITIONAL ASSESSMENT OF SUBSIDENCE RISKS ASSOCIATED WITH NOPS. DO YOU AGREE WITH DR. KOLKER'S RECOMMENDATION?

A. No, I do not. The analyses I performed for my evaluation of any potential subsidence-related risks associated with NOPS, which were summarized under oath in my Direct

Testimony and presented fully in the C-K Technical Report and the Addendum to the C-K Technical Report, confirm that operation of either the CT or the Alternative Peaker will not contribute to subsidence in New Orleans or cause any damage to infrastructure. My independent evaluation involved the use of geotechnical/hydrogeological conceptual site models as well as drawdown and consolidation calculations, the latter of which provides the Council with a conservative, scientific quantification of the worst-case scenario of the possible impacts of groundwater usage associated with NOPS for 50 years of operating the plant. These analyses are on par with, and in some cases above and beyond, industry standards for any analysis of groundwater usage impact assessments and they support my independent and sworn representations to the Council that (i) neither of the proposed NOPS units will increase or contribute to subsidence in New Orleans East or the surrounding areas, (ii) neither unit will cause differential settlement, and, consequently, (iii) neither unit will pose any risk to the integrity of area infrastructure, including the HSDRRS or other flood protection infrastructure.

Dr. Kolker has not disputed, or even commented upon, the accuracy of my calculations. He does not dispute the fact that the drawdown and consolidation calculations I undertook represent valid, industry-standard methods for independently and scientifically evaluating possible impacts of groundwater usage. As such, after two submissions of testimony to the Council, Dr. Kolker has failed to provide the Council with any substantive reason to indicate that my calculations and the conclusions they support are insufficient to provide the independent analyses that he recommends the Council evaluate prior to making a decision on the Supplemental Application.

The Council should also note that although Dr. Kolker had more than enough time to provide his own independent analysis of the possible impacts of groundwater usage on subsidence and the integrity of local infrastructure; he did not. Instead, he recommends that the Council further delay its decision on the Supplemental Application to obtain additional analyses, which Dr. Kolker declined to perform during the course of his involvement in this proceeding. In support of that recommendation, he offers vague, inaccurate, and unfounded criticisms of my Testimonies, which criticisms do not address the merits of the calculations – documented in voluminous reports provided to the Council – supportive of my independent, sworn representations to the Council. It is my professional opinion that the additional studies Dr. Kolker recommends are not needed and would only serve to unnecessarily delay this proceeding. I will again note that, although the course of this proceeding afforded Dr. Kolker, and the parties on whose behalf he submitted testimony, ample opportunity to conduct the studies he recommends to the Council, he failed to do so.

Q24. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF EAST BATON ROUGE

NOW BEFORE ME, the undersigned authority, personally came and appeared, **GEORGE LOSONSKY, PH.D., P.G.**, who after being duly sworn by me, did depose and say:

That the above and 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.

Dr. George Losonsky, Ph.D., P.G.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 14th DAY OF NOVEMBER, 2017

NOTARY PUBLIC

My commission expires: upon death.

TERRI L. REESE
Notary Public
My Commission is for Life