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PUC DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PUBLIC VERSION

DIRECT TESTIMONY OF

DEVI GLICK

ON BEHALF OF SIERRA CLUB

October 26, 2022

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Public Utility Commission of Texas ("Commission" or "PUCT")?

A Yes. I submitted testimony in Texas PUC Docket No. 49831, Docket No. 50997, Docket No. 51415, and Docket No. 52487.

Q What is the purpose of your testimony in this proceeding?

A In this proceeding, I evaluate the recent historical performance of Entergy Texas, Inc's ("ETI") coal plants at Unit 6 of the Roy S. Nelson Generating Plant ("Nelson 6") and Big Cajun 2 Unit 3 and how they are likely to perform going forward. I review steps the Company has taken to evaluate the plants' economics and secure replacement resources. Finally, I provide my recommendations for ETI to commit to certain dates for plant retirement and outline steps the Commission should take to encourage such a commitment by ETI.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I describe Nelson 6 and Big Cajun 2 Unit 3 and discuss ETI's current deactivation plans for the units.

In Section 4, I summarize my analysis on the historical performance of each unit based on data I received from the Company. I review the unit deactivation studies that ETI completed for Nelson 6 and that the Plant operator, Cleco,[1] created for Big Cajun 2 Unit 3. I then outline the costs avoided with early retirement.

In Section 5, I discuss ETI's minimal efforts to procure replacement resources for Nelson 6 and review the Company's replacement resource options.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of ETI's witnesses. I also rely on public information from other PUCT proceedings and other publicly available documents.

[1] Cleco Power, Cleco Cajun, LLC, and Louisiana Generating, LLC (together, "Cleco").

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Both Nelson Unit 6 and Big Cajun 2 Unit 3 have historically incurred costs in excess of their market energy and capacity values. These excess costs have been passed on to ETI ratepayers.
2. ETI's own unit deactivation analysis for Nelson Unit 6 and Big Cajun 2 Unit 3 shows that it costs less to retire and replace the units in [redacted] respectively than to invest the required capital and maintenance costs to maintain them.
3. ETI was not proactive in evaluating replacement resources for Nelson 6 despite knowing for nearly a decade that it would incur high environmental compliance costs to comply with sulfur dioxide (SO_2) regulations.
4. ETI did not take an active role in operating and maintaining Big Cajun 2 Unit 3, or in studying and planning for the unit's retirement and replacement in recent years.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. ETI should commit to a retirement date for Nelson 6 of no later than [redacted] and preferably sooner.
2. ETI should commit to a retirement date for Big Cajun 2 Unit 3 of [redacted]
3. The Commission should limit ETI's spending at Nelson 6 and Big Cajun 2 Unit 3 to only what is required to maintain reliable operations through [redacted], respectively—the dates ETI determined are the optimal end of life for each unit—and consider short-term capacity market

purchases as an alternative to any large investments at either plant. The Commission should required ETI to seek pre-approval for any investments at these plants above $1 Million between now and when they retire.

3. ETI HAS NOT COMMITTED TO RETIREMENT DATES FOR ITS PLANTS AT NELSON 6 AND BIG CAJUN 2 UNIT 3

Q What is ETI proposing in this docket related to Nelson 6 and Big Cajun 2 Unit 3?

A ETI is seeking approval to include in rates costs to operate and maintain Nelson 6 and Big Cajun 2 Unit 3. This includes capital expenditures and operations and maintenance (O&M) costs incurred during the test year.

Q What is the application test year?

A The application is based on a 12-month test year ending December 31, 2021.[2]

Q Please provide an overview on Nelson 6 and Big Cajun 2 Unit 3.

A Nelson 6 is a 521.4 MW coal-fired power station located in Westlake, Louisiana within the West of the Atchafalaya Basin ("WOTAB") load pocket. Nelson 6 is jointly owned by ETI (29.75%), Entergy Louisiana, LLC ("ELL") (40.25%), EAM Nelson Holding, LLC (10.9%), Sam Rayburn G&T, Inc (10%), and East Texas Electric Cooperative ("ETEC") (9.1%).[3] Nelson 6 went into service in 1982 and is currently 40 years old.[4]

[2] ETI Application, page 2.

[3] Direct Testimony of Beverley Gale, page 7.

[4] Direct Testimony of Anastasia R. Meyer on behalf of ETI ("Meyer Direct"), page 13.

Big Cajun 2 Unit 3 is a 554.5 MW coal-fired power plant located near the Mississippi River in New Roads, Louisiana. Unit 3 is jointly owned by Louisiana Generation, LLC (58%), ELL (24.15%), and ETI (17.85%). It is operated by Cleco Cajun LLC. The unit went into service in 1983 and is currently 39 years old.[5] ETI is a minority owner and states in its application that it has limited control over the ongoing operations and retirement of Unit 3.[6]

Q What is the undepreciated balance at each plant?

A The plant balances for Nelson 6 and Big Cajun 2 Unit 3 as of July 2022 were $202.7 million and $111.6 million respectively at the beginning of the test year.[7]

Q Has ETI committed to a retirement date for Nelson 6 or Big Cajun 2 Unit 3?

No, not officially. The Company updated its assumed unit deactivation dates for both units in its rate case application, moving Nelson 6 up from [redacted] and Big Cajun 2 Unit 3 from [redacted].[8] Both units will be [redacted] at the time of their planned deactivations. The timing of the proposed dates for both units aligns with the Company's updated depreciation assumptions.[9] But ETI has not formally committed to retire either of the units on the identified dates.

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[5] *Id.*, pages 15-16.

[6] *Id.*

[7] ETI Response to Sierra Club Request 3-11.

[8] Meyer Direct, page 13.

[9] Direct Testimony of Dane A. Watson on behalf of ETI ("Watson Direct"), Exhibit DAW-2 (HSPM), Appendix D-1.

Specifically, at Nelson, the Company indicated that while ETI and Entergy Louisiana, LLC (ELL) will be assuming a [redacted] deactivation date for the purposes of their upcoming supply plans, they will be continuing to evaluate this assumption.[10] For Nelson 6, the proposed deactivation date [redacted] is also two years later than the economically optimal date of [redacted] identified in the unit deactivation study.[11]

At Big Cajun, ETI indicated that it does not control the decision on when the resource deactivates or retires[12] – Cleco does. And that the only public retirement date Cleco has committed to is 2032 (as referenced in the direct testimony of Company Witness Meyer, on page 19).[13]

Q Are the Company's proposed retirement dates for Nelson 6 of Big Cajun 2 Unit 3 public?

A No. ETI has designated the assumed deactivation dates as confidential citing the competitive nature of the wholesale power market as the justification.[14] This information should be public, and in fact is public in the Entergy Louisiana, 2023 Integrated Resource Plan (Draft Report) submitted to the Louisiana Commission on October 21, 2022.[15] Based on my experience as an expert working in public

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[10] ETI Response to Sierra Club Request 3-2.

[11] Meyer Direct, page 15.

[12] ETI Response to Sierra Club Request 3-8(e).

[13] ETI Response to Sierra Club Request 3-7(a).

[14] ETI Response to Sierra Club Request 3-1.

[15] Entergy Louisiana 2023 Integrated Resource Plan (Draft Report), Submitted October 21, 2022, *available at* https://cdn.entergy-

utility dockets across more than a dozen states, retirement dates are generally public and transparent. It is concerning that ETI seeks to keep it hidden.

4. THE UTILIZATION AND ECONOMIC PERFORMANCE OF NELSON 6 AND BIG CAJUN 2 UNIT 3 HAVE BEEN STEADILY DECLINING OVER THE PAST DECADE AND ETI'S OWN ANALYSIS SHOWS THIS TREND IS PROJECTED TO CONTINUE IF THE PLANTS STAY ONLINE

i. Nelson 6 and Big Cajun 2 Unit 3 have experienced declining utilization and economic performance in recent years

Q How have Nelson 6 and Big Cajun 2 Unit 3 been utilized over the past decade?

A As show in Figure 1 below, the capacity factors at both units have steadily fallen over the past 10 years (since 2011) from a high in the 80 to 90 percent in 2011 to a low of 4 percent and 20 percent for Big Cajun 2 Unit 3 and Nelson 6, respectively, in 2020. Although their utilization rebounded slightly in 2021, their capacity factors are still substantially below historical levels[16] and are projected to continue to be low going forward.[17]

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louisiana.com/userfiles/content/irp/2023/Combined-Public-Report-10-21-22.pdf?_ga=2.184710763.357510662.1666631173-1120267215.1666631173 ("Entergy Louisiana 2023 Integrated Resource Plan").

[16] ETI Response to Sierra Club Request 2-1.

[17] ETI Response to Sierra Club Request 2-2.

Figure 1. Annual capacity factors for Nelson 6 and Big Cajun 2 Unit 3

[redacted]

Source: Entergy Responses to Sierra Club Requests 2-1(c), HSPM Attachment 1 and 2-2(c), HSPM Attachment 1.

Q Describe the units' financial performance in recent historical years.

A Based on the Company's own data, I find that Nelson 6 and Big Cajun 2 Unit 3 each incurred costs in excess of their market energy and capacity value in every year between 2015 and 2021, as shown in Figure 2 and Figure 3 below. This means that in each of the last seven years, both units have incurred costs in excess of market revenues and value, and these excess costs have been passed on to ETI ratepayers.

Figure 2. HSPM Historical costs and revenues for Nelson 6

[redacted]

Source: See description in text.

Figure 3. HSPM Historical costs and revenues for Big Cajun 2, Unit 3

[redacted]

Source: See description in text.

Q Explain the methodology you used to develop this historical analysis.

A I relied entirely on ETI data provided in discovery. For both units, I summed up historical fuel costs,[18] O&M costs,[19] and capital expenditures[20] to find total historical unit costs. I estimated each units' historical capacity value based on its unforced capacity (UCAP)[21] and capacity value in the MISO Planning Reserve Auction (PRA)[22] each year. I summed this capacity value with each unit's energy revenues,[23] ancillary revenues,[24] to produce total historical unit value. I netted the unit costs and value to find each unit's historical net value (or cost) for each year.

ii. ETI's own unit deactivation studies show that ratepayers will be better off if Nelson 6 and Big Cajun 2 Unit 3 are retired in the near future

Q What do the Company's projections show about the units' projected utilization going forward?

A ETI's most recent projections for the units show continued declines in generation from 2022 through the proposed deactivation dates. In the years directly prior to

[18] ETI Response to Sierra Club Request 2-1, HSPM Attachment 7.

[19] *Id.*, HSPM Attachment 3 - Attachment 6.

[20] ETI Response to Sierra Club Request 2-4, HSPM Attachment 2.

[21] ETI Response to Sierra Club Request 2-1(a) HSPM.

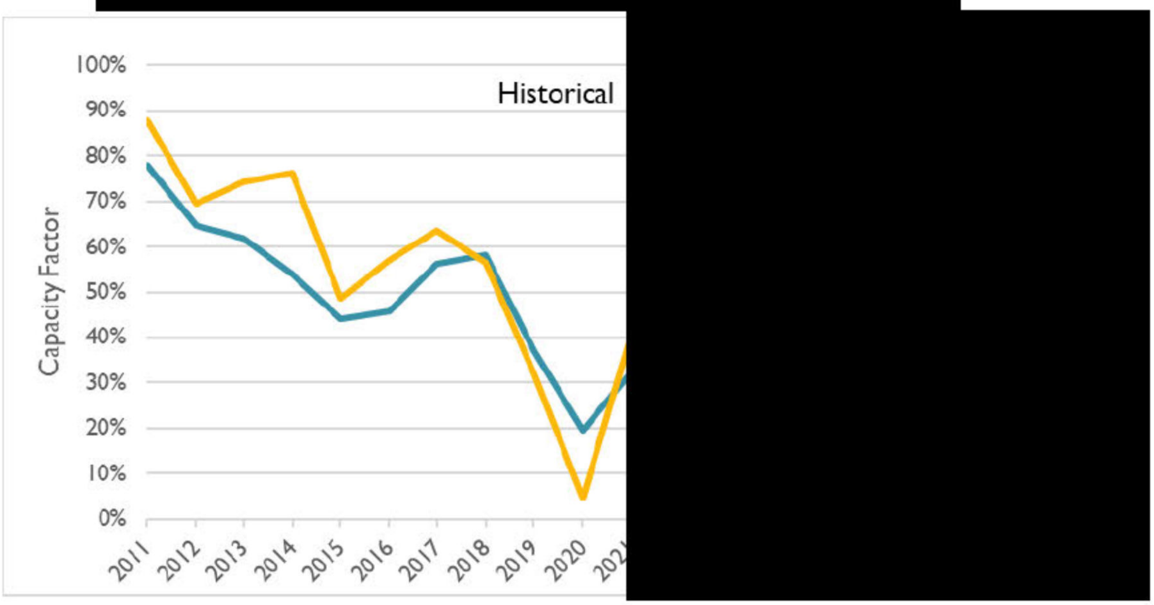
[22] MISO Planning Reserve Auction Results for 2014/2015 Planning Year Through 2019/2022 Planning Year.

[23] ETI Response to Sierra Club Request 2-7, Attachment N6_BC2U3_Ancillary_Energy_Uplift.xlsx.

[24] *Id.*

the Company's assumed deactivation dates for both units, the projected capacity factors for each unit decreases to levels as low as [redacted], as shown in Figure 4 below.[25] In its Business Plan 2022 ETI stated that Nelson 6 is expected to [redacted][26]

[redacted]



Source: See description in text.

Q How did ETI determine the proposed deactivation dates for Nelson 6 and Big Cajun 2 Unit 3?

A The changes in the deactivation date at Nelson 6 that ETI proposes in this application are based on the results of a unit deactivation assessment the Company conducted in August 2021.[27] For Big Cajun 2 Unit 3, the unit deactivation date is set based on a several factors: (1) the results of a deactivation

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[25] ETI Response to Sierra Club Request 2-2.

[26] Meyer Direct, Exhibit ARM-4 HSPM, page 12.

[27] Meyer Direct, Exhibit ARM-3 HSPM.

study conducted by Entergy's Enterprise Planning Group ("EPG"), (2) Cleco's public commitment to retire the unit by 2032, (3) cost projections for emissions reduction technologies, and (4) expiring wholesale electric service agreement termination dates.[28]

Q What has ETI or its co-owner Cleco said about the [redacted] deactivation date for Big Cajun 2 Unit 3?

A The majority owner and operator, Cleco Cajun, has publicly committed to deactivate the unit by 2032. [redacted][29]

Although ETI's application at the PUCT suggests that its assumed deactivation date for Big Cajun 2 Unit 3 is confidential, on October 21, 2022, Entergy Louisiana issued its draft Integrated Resource Plan in the Louisiana Public Service Commission, where the Company represented publicly that it is planning to deactivate Big Cajun 2 Unit 3 in 2025.[30]

Q What did ETI find about the cost of continuing to operate Nelson 6 and Big Cajun 2 Unit 3 relative to alternatives in its deactivation studies?

A In its deactivation studies, ETI found that the cost of retiring and replacing each unit was lower than the cost of continuing to operate and maintain it.

[28] Meyer Direct, pages 18 and 19.

[29] Meyer Direct, Exhibit ARM-4 HSPM, page 11.

[30] Entergy Louisiana 2023 Integrated Resource Plan, page 26.

The unit deactivation study for Nelson 6 shows that retiring and replacing the unit in [redacted] is lower cost than operating it through [redacted]. In other words, the avoided costs from retirement at Nelson 6 were significant; therefore an earlier retirement date was more economic than a later one.

For Big Cajun 2 Unit 3 [redacted][31]

Q Describe the methodologies ETI used in the unit deactivation studies conducted for Nelson 6 and Big Cajun 2 Unit 3.

A The Nelson 6 deactivation study was a limited analysis that compared the cost of deactivating Nelson 6 and replacing it with a combustion turbine ("CT") in [redacted] and in [redacted].[32] ETI did not evaluate operation of Nelson 6 beyond 2030 due to the Company's expectation that the aging plant would require significant investment, including in required emission controls, if the unit stayed online into the 2030s.[33]

The Big Cajun 2 Unit 3 deactivation study was also very limited. ETI included a one-page summary of the Big Cajun 2 Unit 3 Economic Evaluation as an Appendix to its Business Plan 2022. [redacted].

[31] *Id.*, page 18.

[32] Meyer Direct, Exhibit ARM-3 HSPM.

[33] *Id.*, page 2.

Q What avoidable costs at Nelson 6 and Big Cajun 2 Unit 3 did ETI include in its unit deactivation study?

A For Nelson 6, the Company identified four categories of ongoing fixed costs in its deactivation scenario analysis: project capital, project O&M, baseline O&M, and payroll O&M. The results of the study showed that retiring Nelson 6 at the earliest date [redacted] would save ETI roughly [redacted] in net present value terms relative to the latest retirement date analyzed [redacted]. Of this [redacted] in savings, [redacted] in savings comes from avoided capital expenditures [redacted] from avoided fixed operation and maintenance costs.[34] The Company's analysis shows that retiring Nelson 6 at the intermediate date [redacted] results in roughly [redacted] of savings in net present value terms relative to [redacted] retirement. By delaying Nelson 6's retirement from [redacted] to [redacted], the Company will incur an additional [redacted] in otherwise avoidable fixed costs in NPV terms. These amounts do not include savings from avoided environmental compliance costs or variable costs. ETI did not include projected cost data for Big Cajun 2 Unit 3 beyond 2025. The Company indicated that it did not have this information, and that Cleco only provided ETI cost data for the unit out through 2025.[35]

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[34] ETI Response to Sierra Club Request 1-4, HSPM Attachment "TP-52487-00SIE001-X004_HSPM_Capital & Fixed O&M NL6 Deactivation Scenario Analysis 2021_05_24 R2-External.xlsx".

[35] ETI Response to Sierra Club Request 3-9.

Q Which environmental compliance cost are avoidable if Nelson 6 and Big Cajun 2 Unit 3 retire prior to 2030 and why were these costs not included in the unit deactivation analysis?

A The U.S. Environmental Protection Agency's ("EPA") Regional Haze Program regulates SO_2 and nitrogen oxide (NO_X) emissions to ensure acceptable air quality and visibility levels. ETI will be required to invest in emissions reduction technologies to ensure compliance. SO_2 reduction technology is estimated to cost $108.8 Million to $473.8 Million in capital costs if the plant operates into the 2030's, and NO_X reduction technologies are estimated to cost $12.2 Million to $172.3 Million. For Big Cajun 2 Unit 3, the costs of implementing SO_2 and NO_X emissions reduction technologies could cost $94.8 Million annually beginning in 2028. New proposed EPA rules could make NO_X emission limits even more stringent and require the installation of selective catalytic reduction systems totaling approximately $230 Million for Nelson 6 and $214 Million for Big Cajun 2 Unit 3.[36]

Additionally, based on the 2020 effluent limitation guidelines (ELG), ETI would be required to invest in environmental controls at Nelson 6 by 2025 to stay in compliance.[37] ETI's current estimate is that this would cost between $0.4–$3.0 million.[38]

These costs are not included in the unit deactivation studies because ETI determined prior to the analysis (it is not clear exactly how) that it was not

[36] Meyer Direct, page 20.

[37] *See* 40 C.F.R. § 423.13; *see also* Draft Louisiana Pollutant Discharge Elimination System (LPDES) Permit for Entergy Gulf States Louisiana, LLC, Roy S. Nelson Plant in Calcasieu Parish, AI Number 19588, Permit Number LA0059030, Activity Number PER20190001, EDMS Doc. 13216257 at pdf page 42-43 (Apr. 7, 2022), *available at* https://edms.deq.louisiana.gov/app/doc/view?doc=13216257.

[38] Meyer Direct, Exhibit ARM-4, page 24.

economic to invest in these upgrades. If ETI locks in retirement dates for Nelson 6 and Big Cajun 2 Unit 3 in [redacted] respectively (or really any time before 2030) these costs will be avoided.

Q Do you have any other concerns with the unit deactivation analysis for Nelson 6 or Big Cajun 2 Unit 3?

A Yes. The deactivation studies are limited in scope and depth. They are potentially useful as a screening analysis, but the Company did not take a full systems view with this study or compare the costs of retirement of each unit to that of alternative resources, including solar PV, wind, or battery storage. The results provide insights into whether Nelson 6 and Big Cajun 2 Unit 3 should be retired, but they do not help ETI to evaluate what resources or portfolio of resources would be most economic to replace the energy, capacity, and other service currently provided by each unit. The Company did not link its retirement analysis to resource replacement analysis and procurement activities, and now is asking ratepayers to pay excess costs to keep the unit online while replacement resources are procured.

Q What takeaways do you have about Nelson 6 after reviewing ETI's application and analysis?

A The Company's own analysis shows that retiring the unit as soon as possible is the most economic option for ratepayers. The Company is only proposing to delay the retirement of Nelson 6 to [redacted] instead of [redacted] because it claims that it cannot procure sufficient replacement resources in time for the earlier [redacted] date.[39]

[39] Meyer Direct, page 15.

There is evidence, however, that ETI knew it could face increased environmental compliance costs from SO_2 and NO_X compliance at Nelson 6 as a result of the Clean Air Act's Regional Haze program since at least 2015.[40] Nonetheless, ETI imprudently delayed by not considering alternative replacement resources such as solar PV, wind, and battery storage. It is now asking its ratepayers to cover the costs of keeping Nelson 6 online, despite acknowledging that continuing to operate the unit is higher cost than a replacement resource, while it procures new resources.

Q What takeaways do you have about Big Cajun 2 Unit 3 after reviewing the ETI's application and analysis?

Q ETI stated that, as a minority owner, it has limited control over the ongoing operations and retirement of Big Cajun 2 Unit 3. But this does not justify the minimal oversight ETI has exercised over the unit's operation and planning, especially given the high unit costs ETI expects to pass along to its customers. With the limited information we do have about the plant's recent historical performance and projected future economics, I believe it is in the best interest of

[40] *See generally* ETI Response to Sierra Club 4-1 (starting at Bates 058).

ratepayers for ETI to lock in its proposed retirement date and limit future spending at the unit.

5. <u>ETI SHOULD BE PROACTIVE IN SECURING RESOURCES TO REPLACE ITS AGING COAL-FIRED POWER PLANTS</u>

Q What efforts has the Company made to evaluate and procure replacement resources for the units?

A ETI has known since 2014/2015 that it would likely have to install flue gas desulfurization (FGD) technology at Nelson 6 to comply with SO_2 emission limits, but it has made no effort to procure replacement resources. Given the Company's knowledge about environmental compliance costs, the Company should have been proactive in searching out replacement capacity years ago. ETI's inaction here will cost ratepayers money, especially at Nelson 6 which ETI claims needs to stay online at least two years beyond when ETI found was optimal so the Company can secure replacement resources.

Q What are ETI's current and projected capacity and energy needs?

[redacted][41]

[41] Meyer Direct, Exhibit ARM-4 HSPM, page 14.

Q How should ETI determine the optimal portfolio of replacement resources for Nelson 6?

A ETI should issue an All-Source RFP to obtain current market data that reflects the impacts of both the federal *Inflation Reduction Act* (IRA) as well as current inflationary and supply chain challenges. The Company should use the data it receives from the RFP as inputs to its replacement analysis, which should be based on optimized capacity expansion modeling.

Q What type of replacement resources should ETI be considering?

A ETI should be evaluating portfolios of resources that include solar PV, offshore and onshore wind, battery storage, demand-side management, and market purchases.

With the recent passage of the IRA, tax credits available for renewables and battery storage are stabilizing prices in the near term and are expected to drive down prices in the near future. Texas has excellent solar PV potential, which now qualifies for the Production Tax Credit (PTC) and Investment Tax Credit (ITC). Battery storage, which in the past did not qualify for a tax credit, now qualifies for the ITC. [redacted][42] The preference to delay deployment while technology costs fall should be less of an issue now with the ITC offsetting a substantial portion of the project cost.

Offshore wind is poised to become a resource option in the region as well, as Entergy well knows. The media reports that Entergy Corp is actively exploring

[42] *Id.*, page 9.

potential offshore wind projects in the Gulf of Mexico. Specifically, Entergy Louisiana and Entergy New Orleans signed a memorandum of understanding with an offshore wind developer to evaluate offshore wind power in Louisiana.[43] The Gulf waters off the Texas coast have even greater wind potential than off the Louisiana coast.[44]

Additionally, the IRA provided funding for transmission projects. ETI could use this funding to address load pockets, as well as modernize and expand its transmission network to better integrate renewables.[45]

Q Are there sufficient capacity resources for potential procurement by ETI in the near term in the MISO South region in which ETI operates?

A Yes. MISO's most recent near-term (5 years out) resource survey results[46] show large surpluses of capacity resources in the MISO South region across all planning years (2023/2024 through 2027/2028) from *committed* capacity resources. These surpluses range from 5,600 MW (2023/2024) to 3,300 MW in

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[43] Sam Karlin, *Entergy partners with offshore wind developer to explore Gulf of Mexico potential*, nola.com, Sept. 23, 2022, *available at* https://www.nola.com/news/environment/article_2a752480-3b82-11ed-b892-1bbc5fc1d7b6.html.

[44] United States Department of the Interior, Bureau of Ocean Energy Management. Memo on Wind Areas for the Gulf of Mexico, *available at* https://www.boem.gov/sites/default/files/documents//Draft%20Area%20ID%20Memo%20GOM%20508.pdf.

[45] *See, e.g.*, Inflation Reduction Act §§ 1706, 50151, 50152.

[46] 2022 OMS-MISO Survey Results, June 10, 2022, slide 17, *available at* https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf

2027/2028, with a maximum surplus of 6,600 MW in the 2024/2025 planning year. When considering additional potential new capacity resources, as MISO does in each of these annual surveys, the surplus more than doubles in each of the last three years considered. For example, in 2025/2026 an additional 5,500 MW of new capacity is potentially available, for a total possible surplus of 10,900 MW above the reserve margin requirements for the region.

Q Did ETI consider all these replacement resource options and the impact of the IRA in determining replacement capacity for Big Cajun 2 Unit 3?

A No. ETI's is planning to replace the capacity from Big Cajun 2 Unit 3 with the Orange County Advanced Power Station (OCAPS).[47] The Company's application in Docket No. 52487 was based on insufficient and incomplete replacement analysis and resource cost data. Specifically, ETI did not properly consider solar PV, wind, and battery storage as alternatives to the combined cycle plant; it then failed to update its analysis and re-assess the economics of the proposed project after the passage of the IRA. ETI has the opportunity in replacing Nelson 6 to conduct more robust replacement analysis that properly considers the IRA.

Q What do you conclude about ETI's proposed deactivation dates for Nelson 6 and Big Cajun 2 Unit 3?

A ETI's own analysis and testimony in this application show that retiring both Nelson 6 and Big Cajun 3 Unit 3 as soon as possible is in the best interest of ratepayers. Retiring the units in the near term removes two aging resources that ETI itself admits provide marginal energy benefits. It also allows ETI to avoid

[47] Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station, Docket No. 52487.

incurring large ongoing maintenance costs and significant environmental expenditures that are otherwise required for the units to stay online beyond 2028.

ETI should immediately take action to procure replacement resources to enable the timely retirement and replacement of Nelson 6 and Big Cajun 2 Unit 3. The Company should limit spending on the units to what is required to maintain reliability. And ETI should rely on the bilateral or the MISO South region market for capacity in the short term if major life investments are needed at either unit.

Q Does this conclude your testimony?

A Yes.

CERTIFICATE OF SERVICE

I, Joshua Smith, certify that a copy of the foregoing Sierra Club submission was served upon all parties of record in this proceeding on October 26, 2022, by electronic mail, as permitted by the presiding officer.

Joshua Smith
Sierra Club Environmental Law Program

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, S. Kwok, J. Tabernero, R. Wilson. 2021. *A Clean Energy Future for Tampa.* Synapse Energy Economics for Sierra Club.

Glick, D. *2021. Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy*. Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in Application Power Company's Integrated resource Plan filing pursuant to Virginia Code §56-597 *et seq.* On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles." On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilties Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated August 2022

Exhibit DG-2

Public Responses to Requests for Information

Data Requests

ETI Response to Sierra Club Request 2-4

ETI Response to Sierra Club Request 2-7

ETI Response to Sierra Club Request 3-1

ETI Response to Sierra Club Request 3-8(e)

ETI Response to Sierra Club Request 3-9

ETI Response to Sierra Club Request 3-11

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Jasmine Nguyen, Amber Yartym
to the Second Set of Data Requests of Requesting Party: Sierra Club	Sponsoring Witnesses: Beverley Gale Beginning Sequence No. LC415 Ending Sequence No. LC417

Question No.: SIERRA 2-4 Part No.: Addendum:

Question:

For RS. Nelson Unit 6 and Big Cajun II Unit 3, please provide the following:

a. Historical capital expenditures since 2010.

b. Projected capital expenditures through 2030.

c. Provide a specific accounting of all projects and capital expenditures already scheduled or planned at each unit over the next ten years.

d. For each capital expenditure involving more than $1 million, please provide all analyses of the present value of those investments versus retirement or replacement. If the Company did not perform any such analysis, why not?

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

a. Please see highly sensitive attachments (RP-53719-00SIE002-X004-001_HSPM, RP-53719-00SIE002-X004-002_HSPM, RP-53719-00SIE002-X004-003_HSPM) for the for historical capital expenditures for 2010-2026.

b. See company's response to subpart a. Please note our projections only go to [redacted] for Nelson 6 and [redacted] for Big Cajun 2, Unit 3.

Question No.: SIERRA 2-4

c. See the highly sensitive attachment (RP-53719-00SIE002-X004-004_HSPM) for the capital expenditures for years [redacted] through [redacted]. Please note our projections only go to [redacted] for Nelson 6 and [redacted] for Big Cajun 2, Unit 3.

d. No such analysis has been performed for the projects included in the Company's response to subpart c.

The Entergy Operating Companies ("EOCs") are not the operator of Big Cajun 2, Unit 3. Therefore, they do not determine the appropriate capital expenditures for the unit. As explained in the Direct Testimony of Anastasia R. Meyer, Section B, starting on page 15, Cleco Cajun, LLC, is the operator of the plant and makes investment decisions for Big Cajun, Unit 3.

For the generation units for which the EOCs are the operator, including Nelson 6, an evaluation considering deactivation would typically occur on projects with higher levels of investment than the projects listed in the Company's response to subpart c. or for projects that would be anticipated to change the expected life of the unit. Generally, the EOCs evaluate individual projects as to their ability to protect the ongoing safe, compliant, reliable, and efficient operations of the individual sites.

Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Second Set of Data Requests of Requesting Party: Sierra Club	Prepared By: Ryan Gay Sponsoring Witness: Andrew Dornier Beginning Sequence No. LC378 Ending Sequence No. LC378

Question No.: SIERRA 2-7 Part No.: Addendum:

Question:

Provide total energy and ancillary service market revenues for R. S. Nelson and Big Cajun II Unit 3, respectively, for the period 2015-2020. State whether the values represent Entergy Texas' s share or total unit.

Response:

Please see the attachment (TP-53719-00SIE002-X007).

MISO Expense (Revenue)

Unit	YYYY	ETI Ancillary Dollars	ETI Energy Dollars	ETI Uplift Dollars
EES.NELSON6	2015	$ 97.40	$ (16,769,968.22)	$ (687,962.84)
EES.NELSON6	2016	$ (92.41)	$ (18,319,887.91)	$ (64,675.81)
EES.NELSON6	2017	$ (2,082.87)	$ (22,932,687.93)	$ (4,241.70)
EES.NELSON6	2018	$ (26,131.66)	$ (27,791,011.09)	$ (71,257.60)
EES.NELSON6	2019	$ (13,098.09)	$ (14,574,211.67)	$ (89,126.76)
EES.NELSON6	2020	$ (6,475.34)	$ (5,881,158.43)	$ (379,693.97)
EES.NELSON6	2021	$ (36,286.62)	$ (20,031,705.74)	$ (254,894.01)
LAGN.BC2_3	2015	$ (1,540.61)	$ (12,553,274.68)	$ 30,649.81
LAGN.BC2_3	2016	$ (14,499.27)	$ (15,108,866.32)	$ 32,550.33
LAGN.BC2_3	2017	$ (15,582.70)	$ (17,776,398.90)	$ 26,339.02
LAGN.BC2_3	2018	$ (18,422.68)	$ (16,713,685.44)	$ 75,199.62
LAGN.BC2_3	2019	$ (12,998.65)	$ (7,963,004.16)	$ (394,272.39)
LAGN.BC2_3	2020	$ (2,508.57)	$ (992,456.27)	$ (163,036.21)
LAGN.BC2_3	2021	$ (66,232.69)	$ (15,631,776.58)	$ (48,885.92)

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Anastasia R. Meyer
to the Third Set of Data Requests	Sponsoring Witness: Anastasia R. Meyer
of Requesting Party: Sierra Club	Beginning Sequence No. LC2673
	Ending Sequence No. LC2673

Question No.: SIERRA 3-1 Part No.: Addendum:

Question:

Refer to the Direct Testimony of Company Witness Meyer on page 12. Explain why the retirement ages of Nelson 6 and Big Cajun 2 Unit 3 are confidential.

Response:

Due to the competitive nature of the wholesale power market, the public disclosure of confidential information related to amount and timing of generation Entergy Texas, Inc. ("ETI") plans to deactivate likely would cause higher costs that ETI and other Entergy affiliates would have to pay for purchased power, and these higher costs would eventually be paid by ETI's customers. Public disclosure of commercially sensitive information also could result in less favorable terms and higher prices for which ETI can purchase power on a long-term basis. This could result in an increase in the cost of purchased power that ultimately would be reflected in the electric rates paid by retail customers of ETI.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Sierra Club	Prepared By: Phong Nguyen Sponsoring Witness: Anastasia R. Meyer Beginning Sequence No. LC2693 Ending Sequence No. LC2697

Question No.: SIERRA 3-8 Part No.: Addendum:

Question:

Refer to ETI response to Sierra Club RFI 1-6. Please provide responses for Big Cajun for all questions.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.11. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

a. AURORA Electric Market Model, Excel, and Strategic Energy & Risk Valuation Model ("SERVM").

b. February 2021.

c. Big Cajun 2 Unit 3 was modeled using economic dispatch for each year of the analysis.

d. See the highly sensitive attachment provided in the Company's response to Sierra Club 1-6 (TP-53719-00SIE001-X006-001_HSPM) specifically the column for Business Plan 2021.

e. The Big Cajun 2 Unit 3 assessment referred to in the Direct Testimony of Anastasia R. Meyer was not a retirement analysis. The Company does not control the decision on when the resource deactivates or retires. The assessment looked at the avoided cost associated with Big Cajun 2 Unit 3 under a range of useful life assumptions

f. See the highly sensitive attachment (TP-53719-00SIE003-X008-001_HSPM). In addition, see the highly sensitive attachments provided in the Company's responses to Sierra Club 1-5, 1-6, and 3-5.

g. See the response to subpart e.

Question No.: SIERRA 3-8

h. See the response to subpart e.

i.

i. A full load heat rate of [redacted] Btu/kWh was used for Big Cajun 2 Unit 3.
ii. See the highly sensitive attachments provided in the Company's response to Sierra Club 1-5 and 3-6.
iii. See the highly sensitive attachment (TP-53719-00SIE003-X008-002_HSPM).
iv. See the highly sensitive attachments provided in the Company's responses to Sierra Club 1-5 and 3-6.
v. See the highly sensitive attachments provided in the Company's responses to Sierra Club 1-5 and 3-6.
vi. No transmission upgrades were assumed in the analysis.
vii. Power market prices are not an input to the AURORA model. Power market prices are a result of the input assumptions, constraints, and generating unit commitment and dispatch performed by AURORA.
viii. See the highly sensitive attachments provided in the Company's response to Sierra Club 1-4.
ix. See the Company's response to subpart i.iii.
x. See the Company's response to subpart i.iii.
xi. See the Company's response to subpart i.iii.

j. See the response to subpart e.

k.

i. See the Company's response to subpart i.iii.
ii. See the Company's response to subpart i.iii.
iii. There are no specific VOM cost outputs, but these costs are embedded in the variably supply cost outputs of the AURORA model. See the Company's response to subpart f.
iv. This is not an output of the assessment. See the highly sensitive attachment provided in the Company's response to Sierra Club 1-4 for the input information.
v. This is not an output of the assessment. See the highly sensitive attachment provided in the Company's response to Sierra Club 1-4 for the input information.
vi. This is not an output of the assessment. See the highly sensitive attachment provided in the Company's response to Sierra Club 1-4 for the input information.
vii. See the Company's response to subpart i.iii.

l. See the highly sensitive attachment provided in the Company's response to Sierra Club1-4.

Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Sierra Club	Prepared By: Jasmine Nguyen Sponsoring Witness: Beverley Gale Beginning Sequence No. LC2667 Ending Sequence No. LC2667

Question No.: SIERRA 3-9 Part No.: Addendum:

Question:

Refer to ETI response to Sierra Club RFI 2-4(b) regarding projected capital expenditures for Nelson 6 and Big Cajun 3 Unit 2. State whether the Company has projected capital expenditures through each unit' s respective projected retirement date. If the Company has not projected capital expenditures through each unit' s respective projected retirement date, state the duration of the capital projection provided in Sierra Club RFI 2-4(b).

Response:

No. The Company only has current capital expenditure projections for Entergy Operating Company operated units out five years. Cleco[1] provided capital expenditure projections to Entergy Texas, Inc. only to 2025.

[1] Cleco Power, Cleco Cajun LLC, and Louisiana Generating, LLC (together, "Cleco").

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Sierra Club	Prepared By: Josh Paternostro Sponsoring Witness: Allison P. Lofton Beginning Sequence No. LC2671 Ending Sequence No. LC2671

Question No.: SIERRA 3-11 Part No.: Addendum:

Question:

Provide the undepreciated plant balances for Nelson 6 and Big Cajun 2 Unit 3 as of the beginning of the test year.

Response:

The undepreciated plant balances as of the beginning of the Test Year for Nelson 6 and Big Cajun 2, Unit 3 are $202,766,201 and $111,601,353, respectively.

2014/2015 Planning Resource Auction (PRA)

MISO completed its Annual Planning Resource Auction for Planning Year 2014-2015 based on Market Participant Offers submitted between March 27 and 31, and posted final results on April 14, 2014

- This was the second full-year PRA under the Module E-1 Tariff. MISO completed a partial year, Transitional PRA prior to MISO South entities integrating in December 2013.
- The Auction produced three clearing prices:
  1. Local Resource Zone (LRZ) 1 cleared at $3.29 per MW-Day as its Zonal Capacity Export Limit bound
  2. LRZs 2-7 cleared at $16.75 per MW-Day
  3. LRZs 8-9 cleared at $16.44 per MW-Day as constraints related to intra-RTO dispatch ranges bound between the MISO South and the MISO Central/North Regions
- A total of 136,912 MW of Planning Resources were cleared to meet the MISO's resource adequacy requirements. This includes 124,556 MW of Generation Resources, 3,743 MW of Behind-the-Meter Generation (BTMG), 5,457 MW of Demand Response (DR), and 3,156 MW of External Resources (ER).
- The MISO Planning Reserve Margin Requirement (PRMR) increased by 2,475 MW to 136,912 MW from 2013-14 PRA due to; an increase in Coincident Peak Forecast, an increase in Planning Reserve Margin (PRM) from 6.2% to 7.3%, and, an increase in Zone 8's PRMR as the Zonal Local Clearing Requirement was greater than the Zonal PRMR.
- Excess Zonal Resource Credits of 12,201 MW remained after meeting the PRMR, up from 8,659 MW in 2013-14 PRA, but down slightly from the MISO South Transitional PRA, 12,615 MW.

MISO

2014/2015 MISO Planning Resource Auction Results

LRZ	Z1 (MN,ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	System
Demand Forecast	16,540	12,347	8,757	9,680	8,106	17,629	20,791	7,363	22,999	124,212
PRMR (based on CPF)	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,043	25,224	136,537
LCR	15,070	11,739	8,971	8,879	5,002	15,457	21,293	8,417	24,080	N/A
Effective PRMR	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,417	25,224	136,912
Total Offer Submitted	7,045	2,879	9,520	11,370	387	17,985	15,190	9,406	25,966	99,747
Total FRAP applied	12,620	12,352	391	874	7,722	1,846	8,449	397	2,372	47,022
Offer Cleared + FRAP	18,522	14,358	9,787	9,316	8,109	19,551	22,627	8,582	26,059	136,912
Import Limit	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585	N/A
Export Limit	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,616	N/A
ACP ($/MW-Day)	3.29	16.75	16.75	16.75	16.75	16.75	16.75	16.44	16.44	N/A

Participation by Resource Type (System-wide)

Planning Resource Type	UCAP	Unconverted	Fixed Resource Plans	OFFER	Cleared	ZRC Balance
Generation	138,668	3,480	42,394	90,645	82,162	10,632
Behind the Meter Generation	4,071	59	2,141	1,693	1,602	270
Demand Response	5,750	3	1,449	4,298	4,008	290
External Resources	4,238	73	1,038	3,111	2,117	1,009
Energy Efficiency	0	0	0	0	0	0
Total	152,727	3,615	47,022	99,747	89,890	12,201
%UCAP	100%	2%	31%	65%	59%	8%

Appendix - Acronyms

ACP - Auction Clearing Price ($/MW-Day)
CEL - Capacity Export Limit (MWs)
CIL - Capacity Import Limit (MWs)
CPF – Coincident Peak Forecast (MW)
FRAP - Fixed Resource Adequacy Plan (MWs)
LCR - Local Clearing Requirement (MWs)
LRZ - Local Resource Zone
MP - Market Participant
PRA - Planning Resource Auction
PRM - Planning Reserve Margin
PRMR - Planning Reserve Margin Requirement (MWs)
SFT – Simultaneous Feasibility Test
TPRA – Transitional Planning Resource Auction
UCAP - Unforced Capacity (MWs)
ZRC - Zonal Resource Credit (MWs)

MISO

2015/2016 Planning Resource Auction Results

April 14, 2015

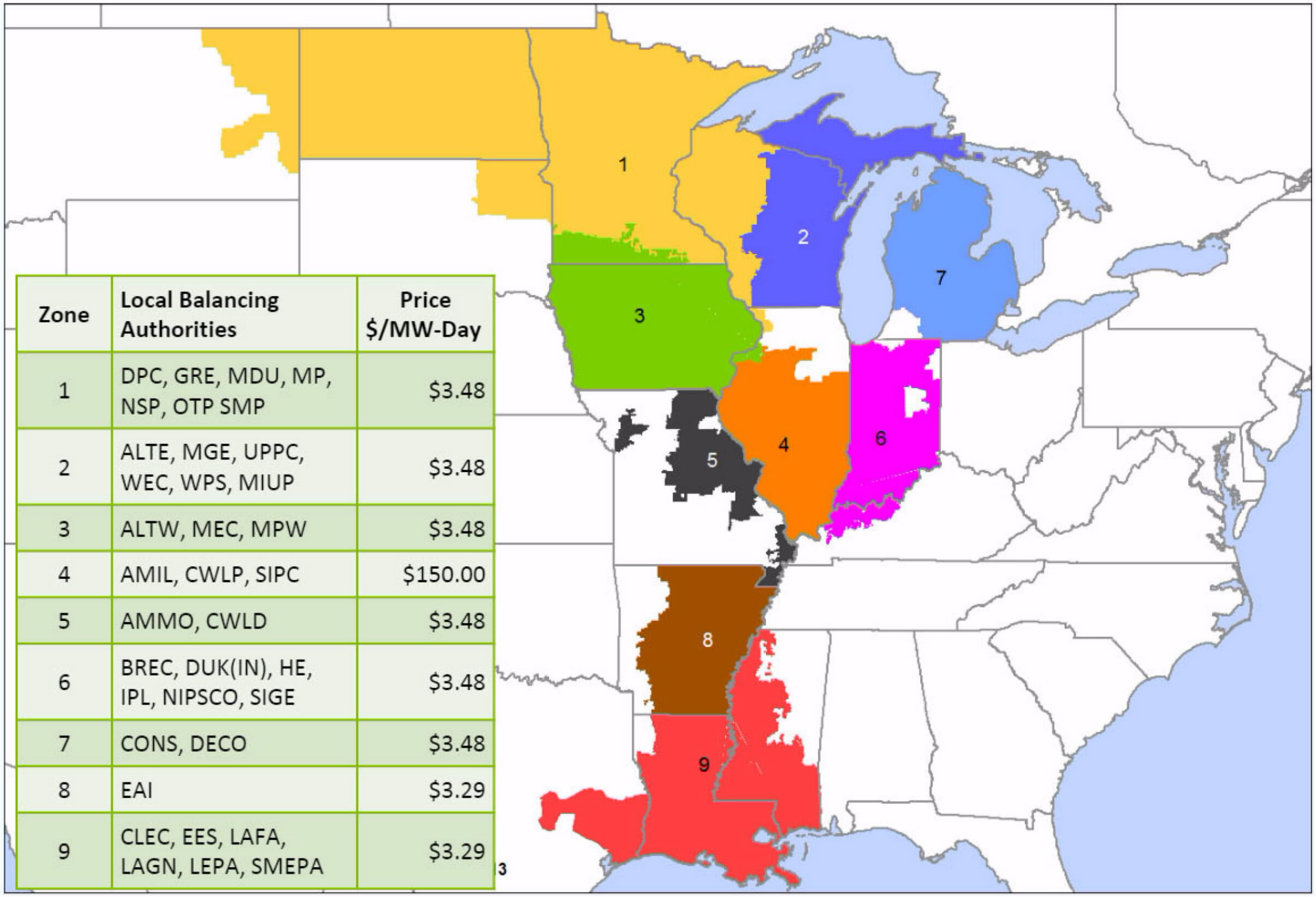
Executive Summary

- **MISO successfully completed its third annual Planning Resource Auction**
- **The MISO region has adequate resources to meet its Planning Reserve Margin Requirements for the 2015/2016 planning year.**
  - Zones 1-3 and 5-7 cleared at $3.48/MW-day
  - Zone 4 (much of Illinois), cleared at $150.00/MW-day
  - Zones 8-9 (MISO South), cleared at $3.29/MW-day

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region as a whole subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - If applicable, Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The zonal capacity requirement must be met with Resources located within the zone
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- The Independent Market Monitor reviews the auction results for physical and economic withholding

2015/2016 Auction Clearing Price Overview



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29

Next Steps: Auction Output and Settlements

- **Key outputs from the auction are:**
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each zone
- **This price drives the settlements process**
  - Load pays the auction clearing price for the zone in which it is physically located
  - Cleared capacity is paid the auction clearing price for the zone where it is physically located
    - External resources are paid the price of the zone where their firm transmission service crosses into MISO
- **When price separation between zones occurs, a zone's use of resources located outside of its boundaries will result in MISO over collecting auction revenues**
  - This over-collection is allocated, per the MISO tariff, to the Load within the zone(s)

2015/2016 Planning Resource Auction Detailed Results

Local Resource Zone	Z1 (MN, ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	SYSTEM
CPDF (Coincident Peak Demand Forecast)	16,525	12,429	8,876	9,518	8,176	17,592	20,522	7,424	23,035	124,097
PRMR (Planning Reserve Margin Requirement)	18,321	13,566	9,768	10,420	8,910	19,409	22,678	8,118	25,170	136,359
LCR (Local Clearing Requirement)	15,982	12,332	8,695	8,852	6,527	14,677	21,442	7,850	23,609	N/A
Total Offer Submitted	4,867	3,071	5,922	11,156	7,926	14,832	14,103	9,562	26,193	97,632
Total FRAP (Fixed Resource Adequacy Plan)	14,494	11,817	4,113	838	0	4,853	9,456	397	2,261	48,229
Offer Cleared + FRAP	18,495	14,497	9,813	8,852	7,885	19,015	23,515	8,526	25,762	136,359
Import / (Export)	(175)	(931)	(45)	1,568	1,026	394	(837)	(408)	(592)	2,988
CIL (Capacity Import Limit)	3,735	2,903	1,972	3,130	3,899	5,649	3,813	2,074	3,320	N/A
CEL (Capacity Export Limit)	604	1,516	1,477	4,125	0	2,930	4,804	3,022	3,239	N/A
ACP (Auction Clearing Price) $/MW-Day	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A

MISO

Key Auction Takeaways: Auction Clearing Prices relative to key thresholds

	Zone 1 (MN, ND, Western WI)	Zone 2 (Eastern WI, Upper MI)	Zone 3 (IA)	Zone 4 (IL)	Zone 5 (MO)	Zone 6 (IN, KY)	Zone 7 (MI)	Zone 8 (AR)	Zone 9 (LA, MS, TX)
2014-2015 Auction Clearing Price (ACP)	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44
2015-2016 Auction Clearing Price (ACP)	**$3.48**	**$3.48**	**$3.48**	**$150.00**	**$3.48**	**$3.48**	**$3.48**	**$3.29**	**$3.29**
2015-2016 Reference Level	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79
2015-2016 Conduct Threshold	$180.43	$180.65	$180.14	$180.53	$181.00	$180.45	$180.59	$179.45	$179.61
2015-2016 Cost of New Entry (CONE)	$246.41	$248.63	$243.48	$247.40	$252.05	$246.60	$248.03	$236.55	$238.22

*All values in $/MW-day

MISO

Key Auction Takeaways

- Price differentials between 2014-15 and 2015-16 results were mainly driven by changes in market participant offers.

- The 2015 price in Zone 4 was also impacted due to the binding of the zonal capacity requirement to procure a certain amount of capacity with the zone (LCR)
  - This requirement for Zone 4 was substantially the same as in the 2014/2015 Auction.

- Zones 8 and 9 cleared at a lower price than the other zones due to the south to north sub-regional power balance constraint binding at 1,000 MW.

Conclusions

- **MISO successfully completed its third annual Planning Resource Auction, demonstrating that the MISO region has adequate resources to meet capacity requirements for the 2015/2016 planning year.**
  - Zones 1-3 and 5-7 cleared at $3.48/MW-day
  - Zone 4 (much of Illinois), cleared at $150.00/MW-day
  - Zones 8-9 (MISO South), cleared at $3.29/MW-day

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- BTMG – Behind The Meter Generator
- DR – Demand Resource
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CPDF – Coincident Peak Demand Forecast (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LOLE – Loss Of Load Expectation
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SFT – Simultaneous Feasibility Test
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- UCAP - Unforced Capacity (MW)
- ZDB – Zonal Deliverability Benefits
- ZRC - Zonal Resource Credit (MW)

2016/2017 Planning Resource Auction Results

April 15, 2016

Revised 4/15/2016 to Include Total Offer Submitted by Zone on Slide 8

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,483 MW
  - Zone 1 cleared at $19.72/MW-day
  - Zones 2-7 cleared at $72.00/MW-day
  - Zones 8-10 cleared at $2.99/MW-day
- Implemented FERC's Order in Docket ER16-833-000 that modified Reference Levels, Capacity Import Limits (CILs) and Local Clearing Requirements (LCRs)
- Regional generation supply is consistent with the 2015 MISO OMS Survey

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- Multiple options exist for Load Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction
- The Independent Market Monitor reviews the auction results for physical and economic withholding

Changes since PRA 2015/2016

- Tariff revisions approved in FERC Docket No. ER16-833-000 implemented, including increased CILs, decreased LCRs, and reduced Initial Reference Level to $0/MW-day

- Sub-Regional Export Constraint in the South to Midwest direction modified to reflect the Settlement Agreement

- LRZ 10 for the State of Mississippi established – No impact

- Other minor changes:
  - EPA RICE-NESHAP* regulations, which likely led to some additional retirements incremental to our OMS survey results
  - Allocation of Zonal Deliverability Benefit revised – pending FERC decision
  - Suspended units required to participate in the PRA – No impact

*Reciprocating Internal Combustion Engine National Emission Standard for Hazardous Air Pollutants

Auction Output and Settlements

- Key outputs from the auction are:
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone

- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

2016/2017 Auction Clearing Price Overview

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$19.72
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$72.00
3	ALTW, MEC, MPW	$72.00
4	AMIL, CWLP, SIPC	$72.00
5	AMMO, CWLD	$72.00
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$72.00
7	CONS, DECO	$72.00
8	EAI	$2.99
9	CLEC, EES, LAFA, LAGN, LEPA	$2.99
10	EMBA, SME	$2.99

MISO

Auction Clearing Prices
$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	**$19.72**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$2.99**	**$2.99**	**$2.99**
Conduct Threshold	*$25.80*	*$26.06*	*$25.52*	*$25.93*	*$26.42*	*$25.85*	*$25.98*	*$24.76*	*$25.12*	*$24.60*
Cost of New Entry	*$258.00*	*$260.58*	*$255.15*	*$259.26*	*$264.19*	*$258.47*	*$259.81*	*$247.56*	*$251.21*	*$246.05*

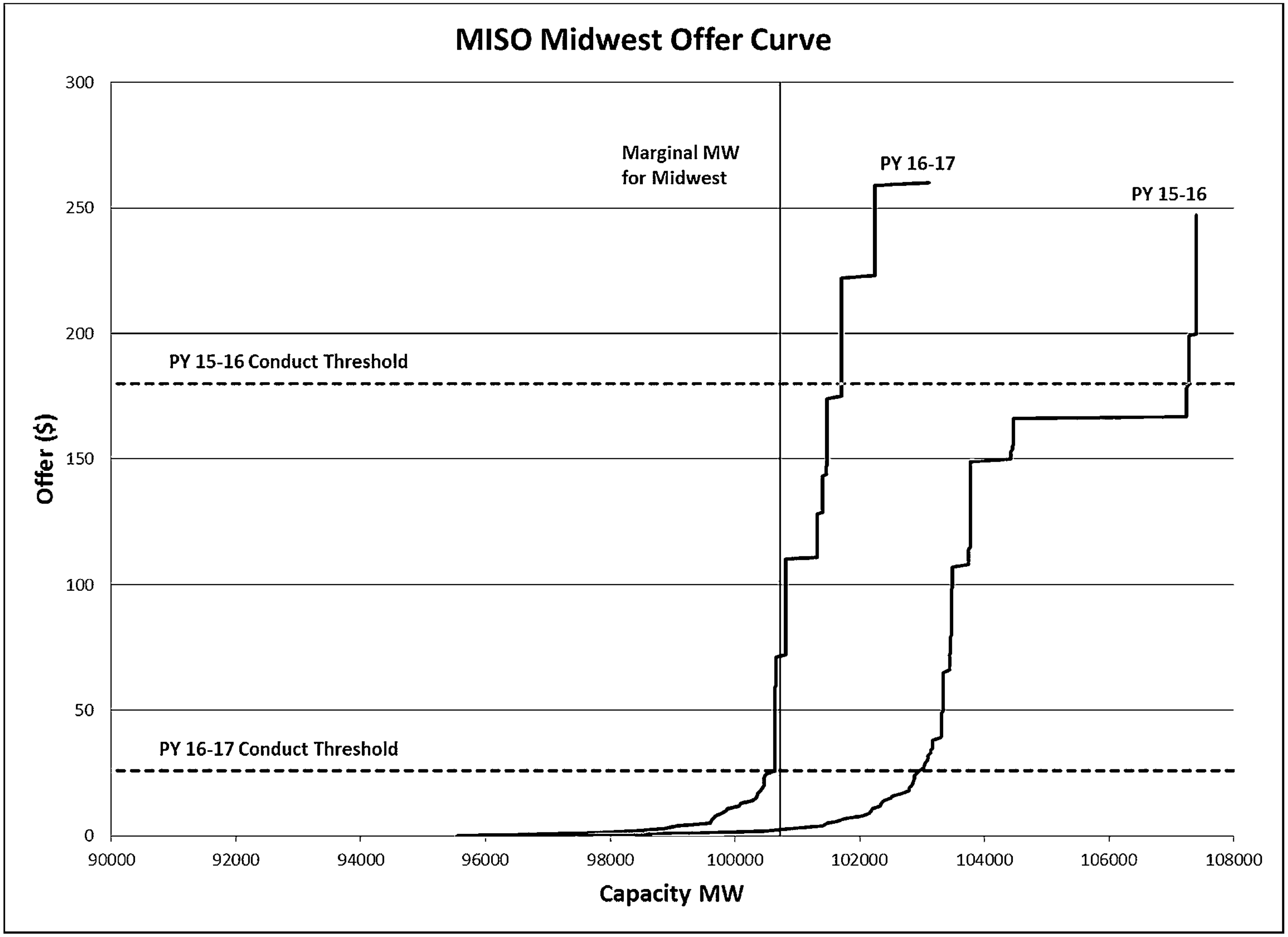
- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a Generation Resource with a Facility Specific Reference Level

* Auction Clearing Price

2016/2017 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,185	13,589	9,879	10,375	8,518	18,750	22,406	8,178	20,713	4,891	135,483
Total Offer Submitted (Including FRAP)	19,430	14,903	10,138	11,371	7,926	18,398	21,615	10,587	20,257	6,899	141,524
FRAP	14,252	12,063	501	910	0	4,338	1,393	318	577	1,641	35,995
ZRC Offer Cleared	4,522	2,840	9,636	8,242	7,927	14,060	20,141	9,676	17,934	4,511	99,488
Total Committed (Offer Cleared + FRAP)	18,775	14,903	10,138	9,152	7,927	18,398	21,534	9,995	18,511	6,151	135,483
LCR	15,918	12,986	8,715	5,476	5,026	13,698	20,851	6,270	17,477	3,978	N/A
CIL	3,436	1,609	1,886	6,323	4,837	5,610	3,521	3,527	4,490	2,653	N/A
Import	0	0	0	1,224	592	352	872	0	2,202	0	5,240
CEL	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857	N/A
Export	590	1,315	258	0	0	0	0	1,817	0	1,260	5,240
ACP ($/MW-Day)	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99	N/A

Midwest Offer Curve 2015/2016 vs. 2016/2017



Next Steps

- Detailed results review at May 5 RASC
- Posting of PRA offer data 30 days after PRA conclusion – May 13

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint

References

- Sub-Regional Export and Import Constraints discussed at the Supply Adequacy Working Group (SAWG)
  - October 29, 2015
  - December 3, 2015
  - February 4, 2016

MISO

2017/2018 Planning Resource Auction Results

April 14, 2017

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 134,753 MW
  - Zones 1-10 cleared at $1.50/MW-day
  - Marginal resource is in Zone 1
  - Increased supply and lower demand in Midwest largely responsible for lower Auction Clearing Prices relative to last year
- Regional generation supply is consistent with the 2016 OMS-MISO Survey
- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement

- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction

- The Independent Market Monitor reviews the auction results for physical and economic withholding

Auction Output and Settlements

- Key outputs from the Auction
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone

- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

Changes since PRA 2016/2017

- Tariff revisions approved in FERC Docket No. ER17-806-000 exempting Demand Resources (DR), Energy Efficiency Resources (EER) and External Resources (ER) from Market Monitoring and Mitigation in the 2017-18 PRA

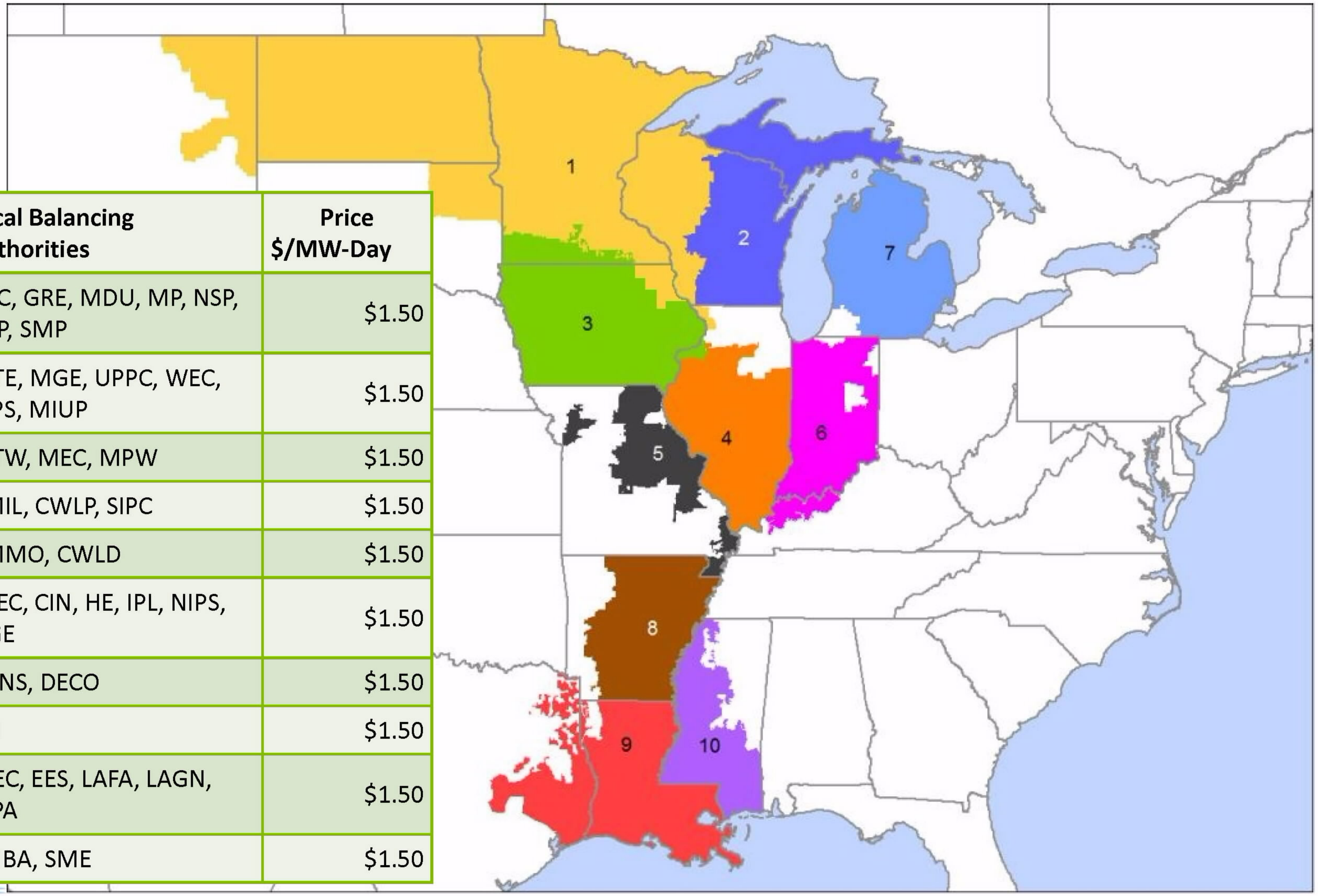
- Tariff revisions approved in FERC Docket No. ER17-806-000 modified the application of the Physical Withholding Threshold to include Market Participants and their Affiliates

- Tariff revisions approved in FERC Docket No. ER16-833-004 established default technology specific avoidable costs, in lieu of providing facility specific operating cost information, to request facility specific Reference Levels from the IMM

- Sub-Regional Export Constraint in the South to Midwest direction increased to a 1500 MW limit from 876 MW and increased to a 3000 MW limit from 2794 MW in the Midwest to South direction

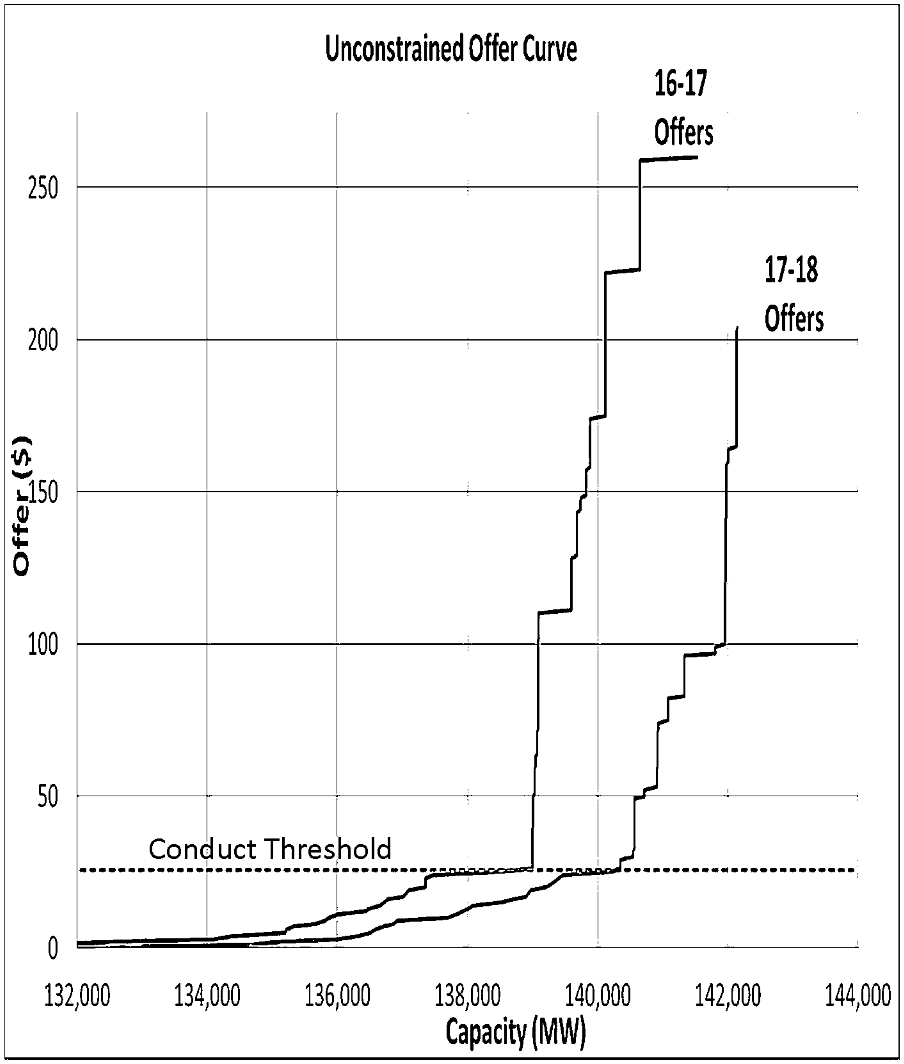
2017/2018 Auction Clearing Price Overview

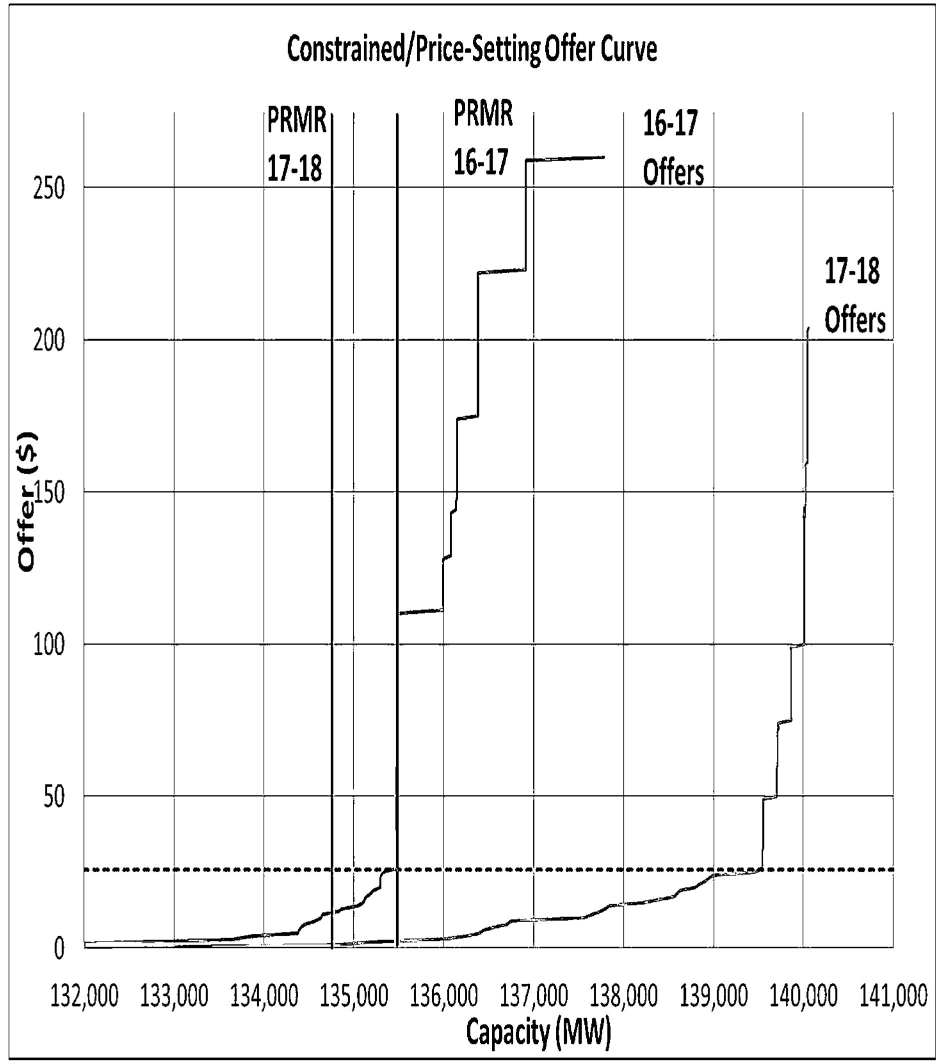
Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.50
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$1.50
3	ALTW, MEC, MPW	$1.50
4	AMIL, CWLP, SIPC	$1.50
5	AMMO, CWLD	$1.50
6	BREC, CIN, HE, IPL, NIPS, SIGE	$1.50
7	CONS, DECO	$1.50
8	EAI	$1.50
9	CLEC, EES, LAFA, LAGN, LEPA	$1.50
10	EMBA, SME	$1.50



MISO

MISO Offer Curve, 2016/2017 vs. 2017/2018





Capacity constrained by export limits from Zone 1 and MISO South

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99
2017-2018 ACP*	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**
Conduct Threshold	*$25.83*	*$26.09*	*$25.53*	*$25.94*	*$26.45*	*$25.85*	*$26.00*	*$24.79*	*$25.14*	*$24.61*
Cost of New Entry	*$258.32*	*$260.90*	*$255.31*	*$259.42*	*$264.52*	*$258.49*	*$260.00*	*$247.94*	*$251.42*	*$246.13*

- Current Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Current Conduct Threshold is $0 for a generator with a facility specific Reference Level

* Auction Clearing Price

2017/2018 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,316	13,366	9,781	9,894	8,598	18,422	22,295	8,329	20,850	4,902	134,753
Total Offer Submitted (Including FRAP)	19,635	15,149	11,009	10,618	7,950	18,718	22,031	10,914	20,392	5,732	142,146
FRAP	14,361	11,559	4,197	712	0	4,155	12,374	470	182	1,454	49,463
Self Scheduled	4,004	2,113	5,575	7,723	7,948	13,009	9,462	9,660	16,505	3,556	79,554
ZRC Offer Cleared	4,568	2,207	6,088	8,412	7,950	14,510	9,583	9,669	18,470	3,833	85,290
Total Committed (Offer Cleared + FRAP)	18,929	13,766	10,285	9,124	7,950	18,665	21,956	10,139	18,652	5,287	134,753
LCR	15,975	11,980	7,968	5,839	5,885	13,005	21,109	6,766	17,295	4,831	N/A
CIL	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910	N/A
Import	0	0	0	771	648	0	338	0	2,198	0	3,955
CEL	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747	N/A
Export	613	400	503	0	0	243	0	1,810	0	385	3,955
ACP ($/MW-Day)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	N/A

Additional Details Regarding Supply

Planning Resource Type	2017-2018 Offered	2016-2017 Offered	2017-2018 Cleared	2016-2017 Cleared
Generation	127,637	127,329	121,807	122,379
Behind the Meter Generation	3,678	3,487	3,456	3,462
Demand Resources	6,704	6,322	6,014	5,819
External Resources	4,029	4,385	3,378	3,823
Energy Efficiency	98	0	98	0
Total	142,146	141,523	134,753	135,483

- Demand Resource quantities include Aggregator of Retail Customers (ARCs) that registered for the 2017-18 PRA
- Registered Energy Efficiency Resources for the 2017-18 PRA for the first time since the 2013-14 PRA

Next Steps

- Detailed results review at May 10 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 12

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- ARC - Aggregator of Retail Customers
- BTMG – Behind the Meter Generator
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CONE – Cost of New Entry
- FRAP - Fixed Resource Adequacy Plan (MW)
- FSRL – Facility Specific Reference Level ($/MW-Day)
- LCR - Local Clearing Requirement (MW)
- LMR – Load Modifying Resource
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZRC – Zonal Resource Credit

References

- Sub-Regional Export and Import Constraints discussed at the Resource Adequacy Subcommittee (RASC)
  - November 2, 2016

- Market Monitoring and Mitigation in the Planning Resource Auction
  - February 8, 2017

MISO

2018/2019 Planning Resource Auction Results

April 13, 2018

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,179 MW
  - Zone 1 cleared at $1.00/MW-day
  - Remainder of footprint cleared at $10.00/MW-day
  - Marginal resources located in multiple Zones
  - Increased demand and lower supply largely responsible for higher Auction Clearing Prices relative to last year
  - ZDB rate of $0.04 will be credited to load in Zones 2 through 10

- Regional generation supply is consistent with the 2017 OMS-MISO Survey

- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement

- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction

- The Independent Market Monitor reviews the auction results for physical and economic withholding

Auction Output and Settlements

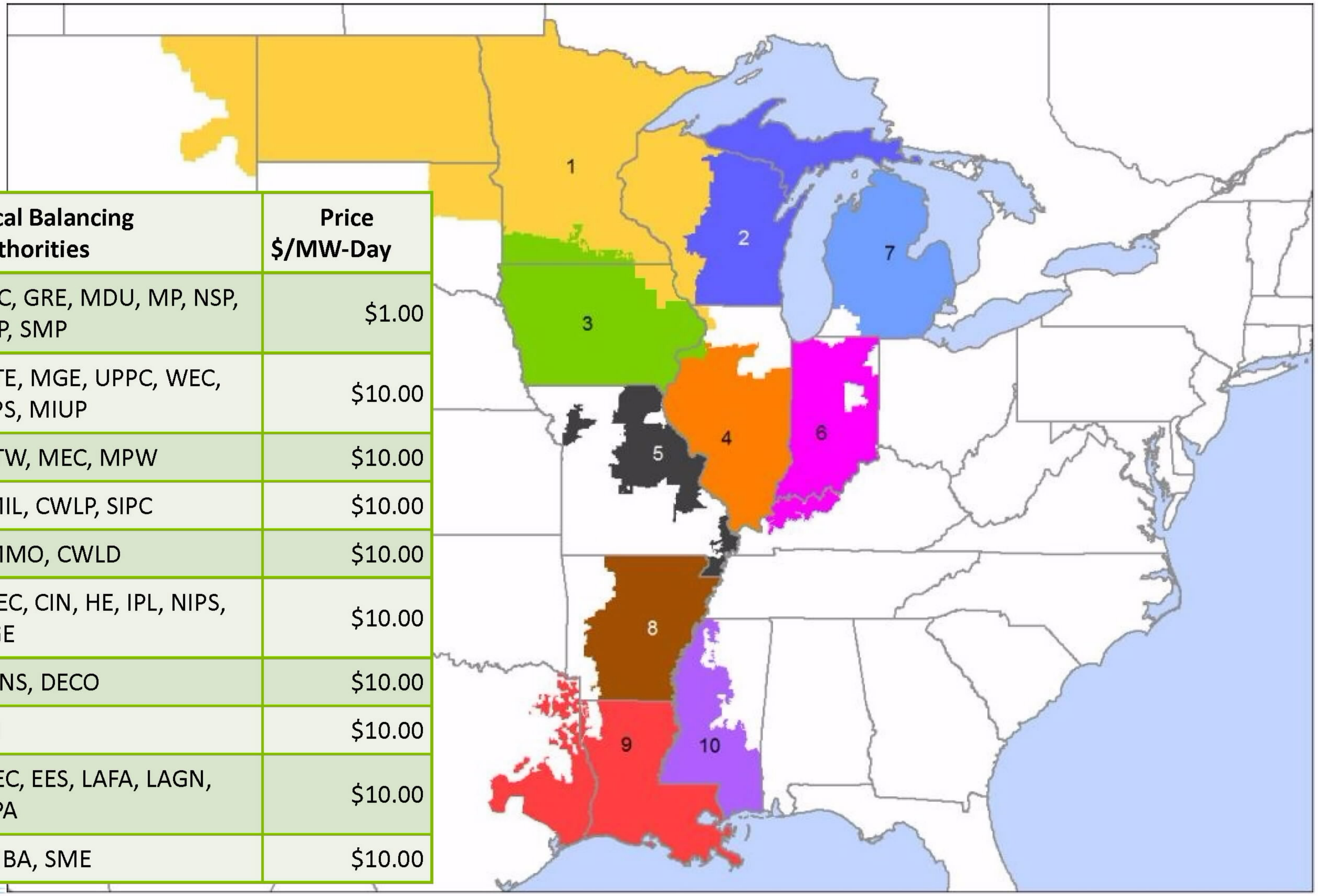
- Key outputs from the Auction
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone

- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

Approved Tariff filings since the 2017/2018 PRA

- Tariff revisions approved in FERC Docket ER17-892-000 and -001 documenting the calculation of Sub-Regional Import and Export Constraints and the Independent Market Monitor's calculation of going-forward costs for Reference Levels.
- Tariff revisions approved in FERC Docket ER17-2112 to authorize the extension or reopening of the Planning Resource Auction ("PRA") offer window when necessitated by unanticipated events.
- Tariff revisions approved in FERC Docket ER18-75-000 to allow Market Participants greater flexibility in the qualification of certain resource types for the Planning Resource Auction, allowing for additional components of Installed Capacity to be deferred in addition to the Generation Verification Test Capacity (GVTC).
- Re-filed Tariff provisions (no changes) regarding Planning Resource Auction re-approved in FERC Docket ER18-462-000.

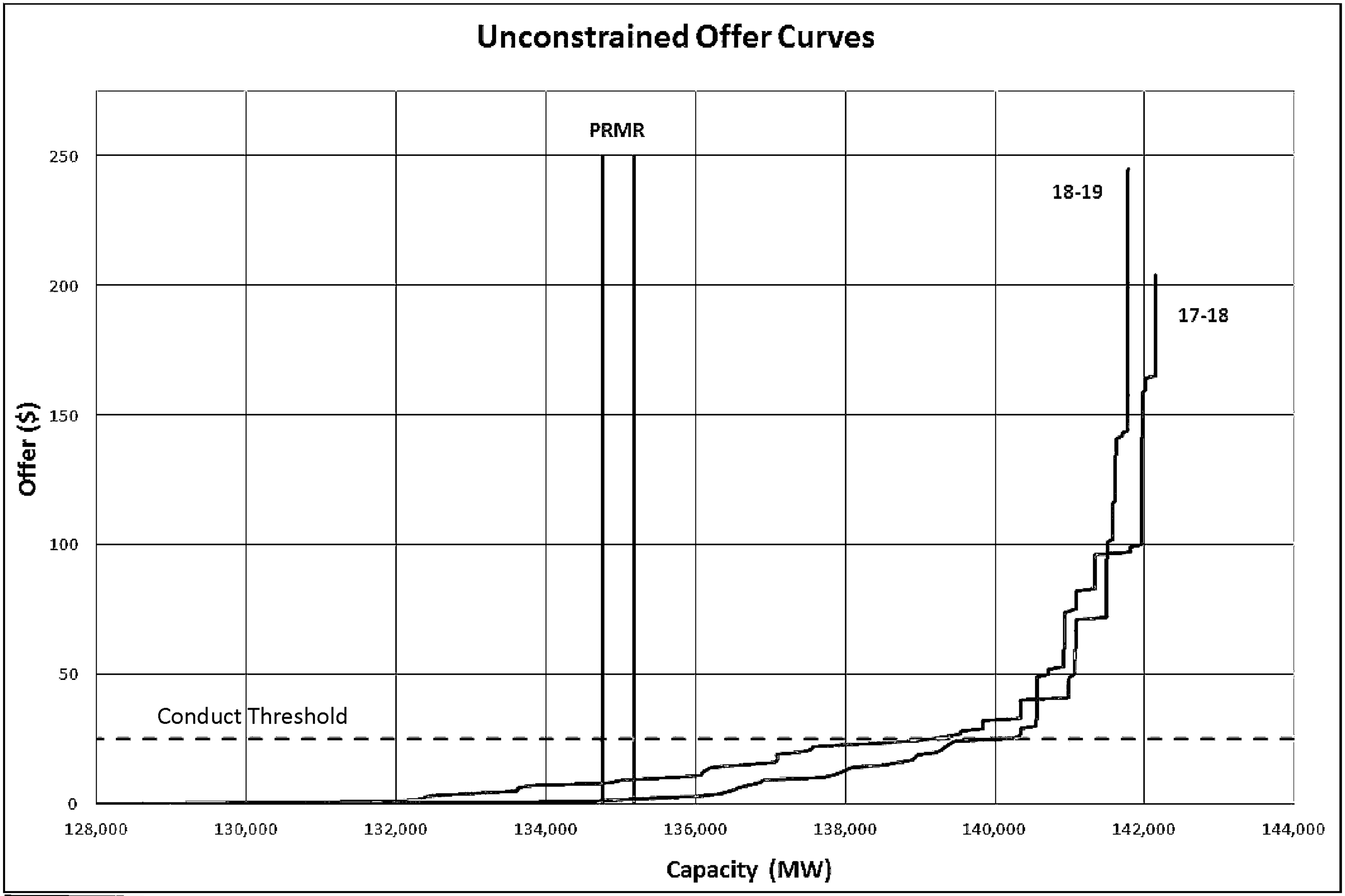
2018/2019 Auction Clearing Price Overview



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00
3	ALTW, MEC, MPW	$10.00
4	AMIL, CWLP, SIPC	$10.00
5	AMMO, CWLD	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00
7	CONS, DECO	$10.00
8	EAI	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00
10	EMBA, SME	$10.00

MISO

MISO Offer Curve, 2017/2018 vs. 2018/2019



MISO

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

<table>
<tr><th></th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th></tr>
<tr><td>2014-2015 ACP*</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td></tr>
<tr><td>2015-2016 ACP*</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td></tr>
<tr><td>2016-2017 ACP*</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td></tr>
<tr><td>2017-2018 ACP*</td><td colspan="10">$1.50</td></tr>
<tr><td>2018-2019 ACP*</td><td>$1.00</td><td colspan="9">$10.00</td></tr>
<tr><td>Conduct Threshold</td><td>$24.76</td><td>$24.25</td><td>$24.35</td><td>$24.62</td><td>$25.07</td><td>$24.45</td><td>$24.86</td><td>$23.63</td><td>$22.81</td><td>$23.63</td></tr>
<tr><td>Cost of New Entry</td><td>$247.59</td><td>$242.47</td><td>$243.48</td><td>$246.22</td><td>$250.66</td><td>$244.52</td><td>$248.60</td><td>$236.30</td><td>$228.11</td><td>$236.30</td></tr>
</table>

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a generator with a facility specific Reference Level

MISO

* Auction Clearing Price

Additional Details Regarding Supply

Planning Resource Type	2018-2019 Offered	2017-2018 Offered	2018-2019 Cleared	2017-2018 Cleared
Generation	126,159	127,637	120,855	121,807
External Resources	3,903	4,029	3,089	3,378
Behind the Meter Generation	4,176	3,678	4,098	3,456
Demand Resources	7,370	6,704	6,964	6,014
Energy Efficiency	173	98	173	98
Total	141,781	142,146	135,179	134,753

- Demand Resource quantities include Aggregators of Retail Customers (ARCs) that registered for the 2018-19 PRA

* Values displayed in MW UCAP

2018/2019 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,414	13,463	9,805	10,060	8,549	18,741	22,121	8,088	20,976	4,963	135,179
Total Offer Submitted (Including FRAP)	19,560	13,954	10,884	11,002	7,944	19,221	22,036	10,939	21,196	5,046	141,781
FRAP	14,431	11,196	4,170	1,136	0	1,803	12,255	440	172	1,428	47,030
Self Scheduled (SS)	4,046	1,930	5,979	6,636	7,934	16,105	9,193	9,706	16,509	2,858	80,896
Non-SS Offer Cleared	453	215	308	1,155	10	1,179	352	241	2,782	558	7,253
Total Committed (Offer Cleared + FRAP)	18,930	13,342	10,456	8,927	7,944	19,087	21,801	10,387	19,463	4,844	135,179
LCR	15,832	12,373	7,374	4,960	5,693	12,090	20,628	4,744	19,319	4,463	N/A
CIL	4,415	2,595	3,369	6,411	4,332	7,941	3,785	4,834	3,622	2,688	N/A
Import	0	121	0	1,133	606	0	320	0	1,513	120	3,812
CEL	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824	N/A
Export	516	0	651	0	0	346	0	2,299	0	0	3,812
ACP ($/MW-Day)	$1.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	N/A

* Values displayed in MW UCAP

Next Steps

- Detailed results review at May 9 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 18
- Results from previous Planning Resource Auctions can be found on the MISO website at: Planning-> Resource Adequacy -> PRA Document

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- ARC - Aggregator of Retail Customers
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- LRZ - Local Resource Zone
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZDB – Zonal Deliverability Benefit
- ZRC – Zonal Resource Credit

MISO

2019/2020 Planning Resource Auction (PRA) Results

April 12, 2019

04/12/2019: MISO Planning Resource Auction (PRA) for Planning Year 2019-2020 Results Posting

Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of nearly 135,000 MW
- Footprint cleared at **$2.99**/MW-day
- Zone 7 (MI) cleared at **$24.30**/MW-day
- Regional generation supply consistent with the 2018 OMS-MISO Survey
- Several offers (~1.5MW) were mitigated by the Independent Market Monitor (IMM) for economic withholding, with a $0.01/MW-day impact on Zone 7.