SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

IURC CAUSE NO. 45086

REBUTTAL TESTIMONY

OF

JUSTIN M. JOINER

DIRECTOR, REGULATORY POLICY & MISO AFFAIRS

ON

BENEFITS OF OWNERSHIP OF RENEWABLE PROJECT
IN VECTREN SOUTH'S ASSIGNED SERVICE AREA

SPONSORING PETITIONER'S EXHIBIT NO. 9
ATTACHMENT JMJ-R1

REBUTTAL TESTIMONY OF JUSTIN M. JOINER

I. BACKGROUND AND INTRODUCTION

Q. Please state your name and business address.

A. Justin M. Joiner
One Vectren Square
Evansville, Indiana 47708

Q. What position do you hold with Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company")?

A. I am Director of Regulatory Policy and Midcontinent Independent System Operator ("MISO") Affairs for Vectren Utility Holdings, Inc. ("VUHI"), the immediate parent company of Vectren South.

Q. Please describe your educational background.

A. I received a Bachelor of Science in Economics and Finance (2005) and a Masters in Business Administration (2012), both from Southern Illinois University at Edwardsville.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission in relation to Vectren's MISO Cost and Revenue Adjustment (MCRA) filing, Cause Number 43354, and most recently MCRA20. I also have testified before the Commission in support of Vectren South's Certificate of Public Convenience and Necessity ("CPCN") for its proposed Combined Cycle Gas Turbine ("CCGT") generation facility, which is docketed as Cause Number 45052.

Q. Please describe your professional experience.

A. I have been employed by the Company since January, 2015. I began my career in the energy industry at Ameren Corporation ("Ameren") and actively participated in the MISO markets in both the regulated and merchant divisions from 2008 to 2013 and directly witnessed the rapid changes in the wholesale energy industry. While at Ameren, I helped manage and optimize Ameren's generation portfolio in the Real-Time and Day-Ahead markets in MISO. Prior to joining the Company, I worked at MISO in the Strategy and Business Development segment where I conducted key industry analysis on market developments such as Resource Adequacy, Footprint Diversity and Gas/Electric Coordination while working to attract and retain membership within MISO. I also was Secretary of the Internal Risk and Audit Committee at MISO.

Q. What are your present duties and responsibilities as Vectren South's Director of MISO Affairs?

A. I have responsibility for investigating emerging regulatory issues, wholesale energy market developments and proposals throughout the country, while overseeing Vectren South's day-to-day involvement with MISO, including oversight of Vectren South's Settlements Department. I am actively engaged in the stakeholder process at MISO and examine MISO initiatives in order to consider the impact to Vectren South. As part of my role and vetting process, I coordinate among our various departments at Vectren South that work with and/or are impacted by MISO developments and provide ad-hoc and scheduled updates to management and senior personnel in regards to industry and market changes. I also lead Vectren South's involvement with its Generator Interconnection ("GI") requests at MISO and have been involved in the process since the original submission and therefore have gained a great understanding of what the GI process involves and what key considerations and impacts may arise as a result.

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

A. My rebuttal testimony addresses certain issues raised in the direct testimony of Indiana Office of Utility Consumer Counselor ("OUCC") witness John E. Haselden, and Alliance Coal LLC ("Alliance") witness Charles S. Griffey. Specifically, I respond to Mr. Haselden's comparison of Vectren South's proposed Solar Project to other publicly announced potential solar projects and Request for Proposal results. I describe the implications of generator interconnection upgrades and transmission congestion on the total cost of a generation project, the requirements and risks of meeting Investment Tax Credit deadlines as a result of the GI process, and MISO market conditions. In whole, I discuss the benefits of owning a renewable generation facility in Vectren South's service territory with respect to controlling congestion and interconnection issues that can arise under purchased power agreements ("PPAs").

II. GENERATOR INTERCONNECTION PROCESS

Q. Do you agree with statements made by Mr. Haselden and Mr. Griffey suggesting the Solar Project would not be adversely impacted by delay?

A. No. Delaying the Solar Project is likely to make it more costly for a number of reasons, including the need to go through the MISO GI process again.

Q. Please explain the MISO GI process.

A. The MISO Generator Interconnection ("GI") process is a three phase study cycle conducted twice annually to study the impact and any associated transmission system upgrade costs as a result of new generation connecting to the MISO transmission system. Each calendar year there is a study cycle in the 1st quarter and 3rd quarter. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle. These two study cycles are the only two periods a project can enter the GI queue each year. Mid-year and mid-queue requests are not allowed. After all modeling details are finalized the study enters the Definitive Planning Phase ("DPP"). The DPP is broken into three phases that are restudies based on immaterial changes to generator attributes and the removal of projects where the requestor decides not to proceed to the next study phase. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. Upon satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate and receive full accreditation in the MISO energy and capacity markets.

Q. How long is this process?

A. MISO's estimate is for the process to take 505 days, start to finish. However, with the record amount of interconnection requests (554 projects currently in the queue that total more than 92.5 GW) in the last two years, the process is averaging over 2½ years per MISO's latest DPP schedule update posted August 1, 2018. As the rush of potential renewable development continues in order to qualify for the full Investment Tax Credits before it begins declining in 2020, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

Q. How many projects in the MISO queue are typically completed?

A. Historically, MISO has seen less than 20% of total GI requests actually completed.[1] Because of this phenomenon, MISO has worked on several iterations of GI queue reform to increase the burden a project must meet before moving into the Definitive Planning Phase (DPP) where GI studies occur. Project withdrawals cause the need for restudies and delay the GI process even further. MISO has increased the requirement for site control and the payment amounts to move through each phase of the GI process. These changes are expected to address the fact that many generation developers submit interconnection requests for projects that are speculative in nature and without rights or options for the location where the GI study is focused.

Q. Is there a cost benefit to a request being submitted to establish a project timeline?

A. Yes. GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying after prior cycles are more likely to be attributed higher costs as a result of prior projects connecting to and exhausting current transmission system topology.

Q. What happens to a project that decides not to move to the next DPP stage?

A. That project is withdrawn from the queue, and depending on which phase it is in, receives a portion of its milestone requirements back. However, the project loses any priority in the queue and must restart the process from the beginning if it decides to resume development.

Q. When is the next study cycle?

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[1] MISO Interconnection Process Task Force presentation "Queue Outlook" – October 17, 2017

A. The next study cycle is March 2019. The application deadline is January 22, 2019. The following cycle would be in July or August of 2019 with an exact date to be determined.

Q. Based on your analysis and experience in the MISO GI queue process, if Vectren South cancels its proposed Solar Project and solicits a Request for Proposal as OUCC witness Haselden recommends, how would the project be impacted?

A. If Vectren South were to cancel its planned Solar Project and begin a RFP process, that would likely not yield results until late 2019, it would lose the priority of its current project in the MISO GI queue and therefore be forced to restart the 2½ year process. Vectren South would not receive a signed GIA until 2022, at the earliest. Accordingly, Vectren South would not be able to start partial construction in 2019 and would not realize the full Investment Tax Credit ("ITC") benefits of 30%. In other words, the proposed delay would greatly reduce the value of the ITC, increase the likelihood of increased GI costs, and risk Vectren South's ability to further pursue the Solar Project. Additionally, it is worth noting that during the timeframe in which Vectren South explored solar projects, there was only one other solar project in the MISO queue that was being studied for interconnection onto Vectren South's system and that project was also owned by Orion. While Orion is still exploring this project, there are currently land right issues impacting its ability to move forward.

Q. Alliance witness Griffey states on page 15 of his testimony that in order for Vectren South to qualify for the Investment Tax Credit that its Solar Project only needs to commence construction in 2019 and be in service by the end of 2023. Do you agree?

A. Yes I do. However, as Mr. Brinkman notes, construction must be continuous. Moreover, MISO's current GI process takes approximately 2½ years per its current posted schedule. As a result, in order to begin construction of a project in 2019, the project must either have submitted a GI request in 2016 or 2017 to have near final upgrade costs determined or begin construction on a project without knowing the costs or knowing if the project is feasible to interconnect to MISO's transmission system. This simply is too great a risk for any generator owner to take on, let alone a Load Serving Entity ("LSE") like Vectren South.

III. SITING OF GENERATION AND IMPACTS ON CONGESTION AND INTERCONNECTION COSTS

Q. Page 12 of OUCC witness Haselden's testimony references NIPSCO's IRP Public Advisory Meeting 3, PowerPoint Presentation, Slide 19, and suggests this demonstrates 16 Indiana solar projects bid an average price of 3.6 cents/KWh. Do you agree with the conclusions drawn by Mr. Haselden?

A. No. First, I would note that contrary to Mr. Haselden's testimony, the slide does not reflect that all of the projects are located in Indiana. The referenced NIPSCO All-Source Request for Proposal Results Summary data is only provided by generator technology type and groups all bids based on specific technology type into one average price. The slide referenced shows 35 solar proposals, of which 9 are asset sales or options and 26 are PPAs. Slide 14 of the referenced NIPSCO presentation shows that of the 35 proposals, the locations varied – with projects located in Illinois, Iowa and Indiana.

Q. Depending on the location of the NIPSCO solar project, what other expenses might be associated with the delivery of power to the utility's system?

A. Location of a generator has two large cost impacts: cost of congestion and cost of interconnection. Typically speaking, the further a generator is located from the load it serves, the greater the potential for price separation, which is demonstrated through the concept of congestion. Quite simply, congestion represents limitations on the transmission system in the form of positive or negative price signals for generators to either increase or decrease production. With an intermittent resource, such as solar, it is extremely important to consider congestion, especially with respect to a PPA or feed-in arrangement as witness Haselden recommends. The intermittent nature of renewable generation makes it less able to respond to system conditions and thus a potential contributor and irritant to system congestion. Renewable PPAs typically include take or pay provisions that require the purchaser to pay for the production from the renewable generator regardless of financial or market conditions.

Q. How do such take or pay provisions typically impact the price of power under a PPA?

A. Congestion occurs at virtually every 5-minute Locational Market Price (LMP) interval per MW and can have an extremely expensive impact over the life of the generator or PPA.

The epitome of congestion is demonstrated via negative LMPs. When negative LMPs occur, the generator is greatly contributing to a system constraint and is paying the MISO market to produce energy. Take or pay provisions require the purchaser of the PPA to take the energy production during negative pricing periods or pay the contracted amount without receiving energy. Hence, the generator is losing money and paying for a service that it typically receives revenue for. Vectren South has experienced this first-hand with PPAs it has in place with wind farms located greater than 50 miles from its load. As demonstrated in the table below, renewable generators located away from Vectren South's footprint experience substantially greater amounts of impactful congestion in the form of negative LMP hours.

Negative LMPs for the period August 2013 – July 2018		
Generation Source (Location of Generator)	**Day Ahead Hours with Negative Pricing**	**Real Time Hours with Negative Pricing**
Brown (Evansville, IN)	27	192
Culley (Evansville, IN)	25	196
Benton County (Earl Park, IN)	2,082	4,868
Fowler Ridge (Fowler, IN)	1,027	1;806

Q. Are there other costs that increase when a project is located a greater distance from the load it serves?

A. Yes. GI costs are greatly impacted by the location of a generator. The MISO GI process involves a nearly 2½ year long process that identifies transmission upgrades and cost responsibilities as a result of a new generator connecting to the MISO transmission system. The costs are allocated proportionately to the generator that causes or contributes to a constraint, and as discussed earlier in my testimony, projects studied after prior projects are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying after prior cycles are more likely to be attributed higher costs as a result of prior projects connecting to and exhausting current transmission system topology. Additionally, projects that are located in areas that already have a large number of generation units or that have existing constraints are likely to have substantial upgrade requirements, the total costs of which are not finalized until the end of the 2½ year GI process and stipulated in the GIA.

Q. Given those costs, could the cost of power generated by the referenced NIPSCO RFP proposals be higher?

A. Most definitely. When analyzing the cost of generation, the total delivered cost is the true indicator of the project's value. Therefore, the total delivered cost includes the cost of the generator itself plus the required GI upgrades, the transmission service to deliver the energy to a specific point and the estimated cost of congestion.

Q. Page 11 of OUCC witness Haselden's testimony references a potential Hoosier Energy 20-year, 200 MW PPA with Riverstart Solar Farm (Riverstart) in Randolph County with a cost in the 4 cents/kWh range. Depending on the location of the solar project what other expenses might be associated with the delivery of power to the utility's system?

A. Similar to the considerations that need to be taken for the responses to NIPSCO's RFP, the Riverstart project will have interconnection and congestion cost components. A review of the public MISO GI queue posting as of September 12, 2018 shows that there are not any GI requests in Randolph County for MISO to begin the nearly 2½ year GI process to study and identify these potential costs.

Q. Given those costs, could the cost of power generated by the Riverstart project be higher?

A. Yes. Since there is not a GI request for the project, there is not official MISO identification of potential upgrades. Therefore, the 4 cents/kWh is either based on a flat interconnection and congestion assumption that has not been preliminarily confirmed by MISO, or the estimate excludes GI and congestion cost consideration altogether.

Q. Page 15 of OUCC witness Haselden's testimony states that the price under the terms of a PPA should be lower than that of a utility-owned project, because merchant companies are more leveraged. Are there other costs not necessarily factored into a PPA that the utility must incur?

A. Yes. Each PPA is unique, but under the terms of most PPAs, there is a stated contract amount of capacity and a take or pay provision for energy in order for the owner of the generator to realize the maximum ITC. Additionally, depending on the structure of the PPA there may be limits on the costs that the developer will pay for interconnection and transmission delivery of the energy, thus placing a cap on these costs and exposing the utility to the risk of overages. Accordingly, regardless of the utility's energy needs or market conditions, a utility that enters into the PPA has to pay for the energy generated up until the contracted amount so as not to financially harm the owner of the generator. This term of a renewable PPA adds additional cost by forcing the purchaser of the PPA to pay the grid during periods of negative pricing, in addition to the price of the PPA. A PPA that would grant ITCs to the PPA purchaser would require additional expense.

Owning the Solar Project, on the other hand, allows Vectren South to manually curtail the generator during highly constrained periods when it is financially prudent to do so, thereby preventing the Company from incurring further costs and preventing the project from contributing to a system issue.

Q. Alliance witness Griffey says on page 12 of his testimony that siting a solar facility in Indiana is not a reason for customers to pay more: "While locating the solar facility in Indiana at the proposed location may lessen the risk of congestion while having lower interconnection cost, nature's limitations on solar radiation cause the facility to have a relatively low capacity factor and thus a much higher cost per kWh." Do you agree?

A. I agree with Mr. Griffey that a solar facility at the proposed location lessens the risk of congestion and lowers the interconnection cost. However, I do not agree that Vectren South customers would be paying more. First, as discussed earlier in my testimony, the risk of congestion is substantial and can be very expensive over the life of a generator. Also, without being far along in the MISO GI queue process, it is unknown what the MISO GI and Affected Systems' costs will be. Absent certainty with respect to these costs it is baseless to claim Vectren South customers would be paying more for the Solar Project. The awareness of this cost uncertainty and risk makes Vectren South's Solar Project even more attractive. The Solar Project is in the February 2017 GI queue and has already received 2nd Phase GI cost estimates that are under budget and on time for a signed GIA to be executed as early as next June.

Second, Southern Indiana is a good location for solar generation, especially in the MISO Central and North Region. MISO currently awards 50% Unforced Capacity (UCAP) accreditation to solar capacity in MISO. Early estimates from experts we have worked with suggest this solar facility will achieve a higher UCAP rating once operational. Although Mr. Griffey believes that UCAP accreditation is not the proper way to think about capability to serve load relative to other types of generation, it is the MISO and industry method. As Mr. Griffey explains on page 18 of his testimony, UCAP measures the amount of generation that can be expected to meet peak load. MISO's peak load historically occurs in the afternoon of August when solar energy generation is at its highest outputs. Because of this, Mr. Griffey attempts to recalculate the cost of Vectren South's project using methods to minimize the value of Vectren South's Solar Project by minimizing the amount of capacity it provides and hence increasing the average MW cost of the Solar Project.

IV. MISO MARKET CONDITIONS

Q. Do you agree with Mr. Griffey's market assessment on MISO energy and capacity prices, on page 21 of his testimony? Specifically, do you agree it is unlikely that MISO prices will be high in the short-term and continue to be high?

A. No I do not. First, Mr. Griffey does not qualify what constitutes "high" prices. Secondly, I do not claim to know what future prices will be, but note that it is important to appreciate current developments with regards to MISO's resource adequacy picture and generation fleet transition. Mr. Griffey cites the last several years' worth of energy prices and last two years of capacity prices in MISO as the basis for his claims. However, what has occurred in MISO and what may occur are two different topics. MISO is in the middle of a fleet transition that is tightening capacity and causing capacity shortfall projections in MISO as early as 2019. As such, MISO is in the middle of several market reforms that are changing energy market principles and outcomes.

MISO is working on several market developments, proposals, and implementations as part of its Market Roadmap, which is an annual prioritization of projects and initiatives developed by MISO and its stakeholders and Resource Availability and Need ("RAN") initiative to enhance MISO's energy and capacity market services. Specifically:

- Extended Locational Marginal Pricing (ELMP): implemented Phase 2 on May 1, 2017;
- Emergency Pricing: implemented on July 1, 2017;
- 5-minute Settlement: implemented July 1, 2018;
- Tightened threshold for un-instructed deviation: presented at the MISO Market Subcommittee for further consideration;
- Locational/External Capacity Zones: to be re-filed with FERC this year;
- Capacity Performance: currently being evaluated as an improvement to PRA and part of the RAN effort; and
- Seasonal Capacity Auction: also currently being evaluated and part of the RAN effort.

The full realization of all of the pending and recent market changes will take time. However, changes are starting to occur in the energy markets as seen directly in the 13% increase over the last four years in both the Real-Time and Day-Ahead around-the-clock energy prices of the major MISO pricing hubs (Illinois, Indiana, Michigan, Texas, and Louisiana):

Year	MISO Real-Time ATC Average	YoY % Change	MISO Day-Ahead ATC Average	YoY % Change
2018 (YtD)	$32.18	4.46%	$32.79	6.55%
2017	$30.80	11.82%	$30.77	10.71%
2016	$27.55	-3.52%	$27.80	-2.71%
2015	$28.55	-	$28.57	-

Additionally, the last two years of capacity auction results do not demonstrate the full volatility in MISO's capacity market. As demonstrated below, there has been consistent volatility the last 5 auctions and the swings in prices have been severe:

MISO Planning Year	Highest Clearing Zone Price in MISO	YoY % Change	Zone 6	YoY % Change
2018-19	**$10.00**	567%	**$10.00**	567%
2017-18	**$1.50**	(98%)	**$1.50**	(98%)
2016-17	**$72.00**	(52%)	**$72.00**	1969%
2015-16	**$150.00**	796%	**$3.48**	(79%)
2014-15	**$16.75**	-	**$16.75**	-

Q. Are there circumstances that can cause the Vectren South capacity position to change and be exposed to this market volatility?

A. Yes. Vectren South's capacity position is based on several assumptions and factors that influence the MISO Planning Reserve Margin Requirement ("PRMR") that dictates the amount of capacity Vectren South must have on hand.

Q. Please describe the mechanics of the PRMR.

A. The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in ten years and therefore is the specific amount of Zonal Resource Credits ("ZRCs") required of each Load Serving Entity ("LSE") to meet its Resource Adequacy Requirements based on its Coincident Peak Demand. ZRCs is MISO terminology for the MWs of capacity MISO's formulas require LSEs such as Vectren South to hold. Each LSE has a calculated PRM, which is the level of capacity above the forecasted Coincident Peak Demand that each LSE must provide. The PRMR calculation is driven by four factors; external non-firm support, load forecast uncertainty, load, and generation. External non-firm support refers to the diversity of load between MISO and neighboring systems and areas outside of MISO that allow for limited support and transfer of capacity. An example would be generators in PJM providing capacity to MISO load. Load forecast uncertainty is due to variability of economics and weather that impact the demand for energy and increase the uncertainty of forecasts. The greater the Load Forecast Uncertainty, the greater the PRMR. Finally, an LSE's PRM reflects the size and outage rate of its units. The frequency and duration of un-planned, "forced" outages in MISO has increased. This is especially impactful during peak summer months when MISO forced outages have increased since 2013. Forced outages peaked in June of 2013 at 10.5 GW and in July of 2017 that number increased to 11.7 GW. MISO has attributed this phenomenon to its aging generation fleet.

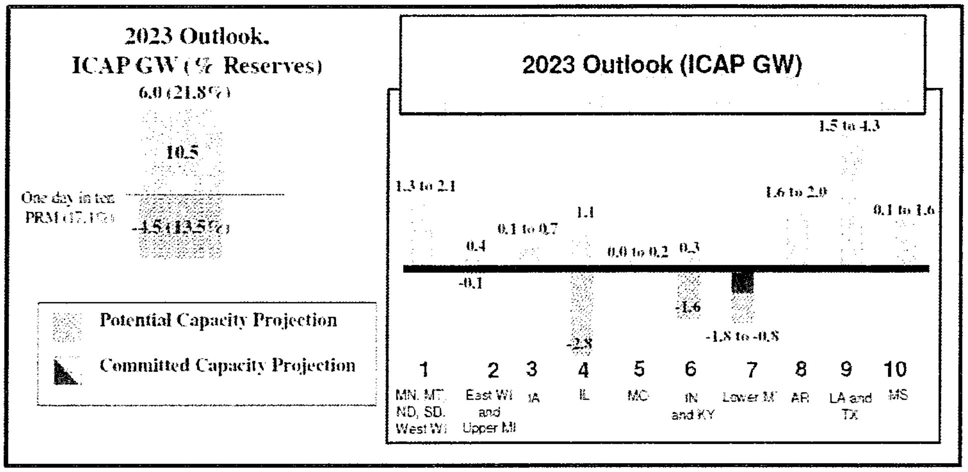
Q. Has the MISO system-wide PRMR increased in recent years?

A. Yes. There has been consistent increase in the annual PRM as shown here:

Planning Year	MISO-wide Planning Reserve Margin (ICAP)	MISO-wide Planning Reserve Margin (UCAP)
2018/19	17.1%	8.4%
2017/18	15.8%	7.8%
2016/17	15.2%	7.6%
2015/16	14.3%	7.1%
2014/15	14.8%	7.3%

Q. Is there a risk that capacity will not be available for Vectren South to purchase?

A. Yes. The Organization of MISO States ("OMS") and MISO began an annual survey in 2013 to capture 10-year resource adequacy projections. The survey is used to compare load projections with generation portfolio plans and measure the two against the annual PRMR. The survey is sent to MISO members, has a 97% response rate and is the primary tool MISO uses for resource adequacy projections. This past June, the 2018 OMS-MISO Resource Adequacy Survey was released and demonstrated a potential capacity shortfall beginning as early as 2020. This potential shortfall increases and could be as much as 4,500 MW by 2023. With respect to Zone 6 (Vectren South's Zone) the survey shows a potential shortfall of 1,600 MW by 2023. The tightening of supply in MISO that is demonstrated in the 2018 OMS-MISO Resource Adequacy Survey and current market reforms that have been proposed to FERC and/or are being discussed at MISO stakeholder meetings make it unreasonable to assume that capacity and energy will be available in future years and at an economic price. The survey's 2023 outlook, by zone, is represented below:



A copy of the entire survey results is attached here as Petitioner's Exhibit No. 9, Attachment JMJ-R1

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A MISO-side capacity shortfall would mean that MISO members would all be competing for a finite amount of external capacity that would have to be pseudo-tied, which is essentially transmission service assigned from a neighboring RTO that would allow for it to be recognized as MISO capacity.

V. <u>CONTARY TO MR. GRIFFEY'S SUGGESTION XCEL ENERGY IS REPLACING COAL WITH SOLAR</u>

Q. Page 17 of witness Griffey's testimony references XCEL Energy's (XCEL) CEO's recent comments on the future cost of solar to support Mr. Griffey's expectation that an RFP would yield lower costs. Has XCEL delayed its plans to implement solar additions to its resource portfolio?

A. No. Alliance witness Griffey references the following comments from XCEL's CEO during a July 2018 earnings call:

> "And I believe solar is going to continue to fall in price and very quickly offset the fall off of the ITC. So I'm more inclined to match our solar resources with our capacity needs....because we think the technology is going to continue to improve, and we'll have other opportunities to lock in great prices."

The statement was made during XCEL's July 26, 2018 earnings call. However, on August 28, 2018 the Colorado Utility Commission issued a bench order for its staff to prepare a final written order to approve XCEL's $2.5 billion Colorado Energy Plan that retires coal and replaces it with a combination of natural gas and renewables, including 700 MW of solar. This timing allows XCEL to commence construction in 2019 to fully realize ITC benefits. Thus XCEL will move ahead with significant solar projects.

VI. CONCLUSION

Q. Please summarize your rebuttal testimony.

A. In my opinion, the addition of the Solar Project to Vectren South's generation portfolio is reasonable and in the public interest as a means to effectively diversify Vectren South's generation while positioning Vectren South and its customers for market, transmission system, and political changes. Contrary to Mr. Haselden's testimony, the development of the Solar Project as a Company-owned generation source is far superior to entering into a PPA or feed-in type arrangements. Owning the resource allows maximum operational flexibility to react to market and system conditions. Furthermore, owning a renewable project in Vectren South's service territory minimizes the sizeable risk of obtaining energy from a distant resource that would then be susceptible to 5-minute interval congestion costs for the remainder of the life of the asset or the PPA. In summary, the Solar Project is the culmination of lessons learned from ongoing issues with renewable PPAs and from our recent RFP process centered on a CCGT and the modeling that demonstrated the sizable financial impacts of just slight price separation between the generation and load nodes. The Solar Project mitigates these real cost risks.

Q. Does this conclude your prepared rebuttal testimony?

A. Yes it does.

VERIFICATION

I, Justin M. Joiner, Director of Regulatory Policy and Midcontinent Independent Systems Operator ("MISO") Affairs for Vectren Utility Holdings, Inc,. under the penalties for perjury, affirm that the answers in the foregoing Rebuttal Testimony are true to the best of my knowledge, information and belief.

Justin M. Joiner
Director, Regulatory Policy and MISO Affairs

2018 OMS MISO Survey Results

Furthering our joint commitment to regional resource assessment and transparency in the MISO region, OMS and MISO are pleased to announce the results of the 2018 OMS MISO Survey

June 2018

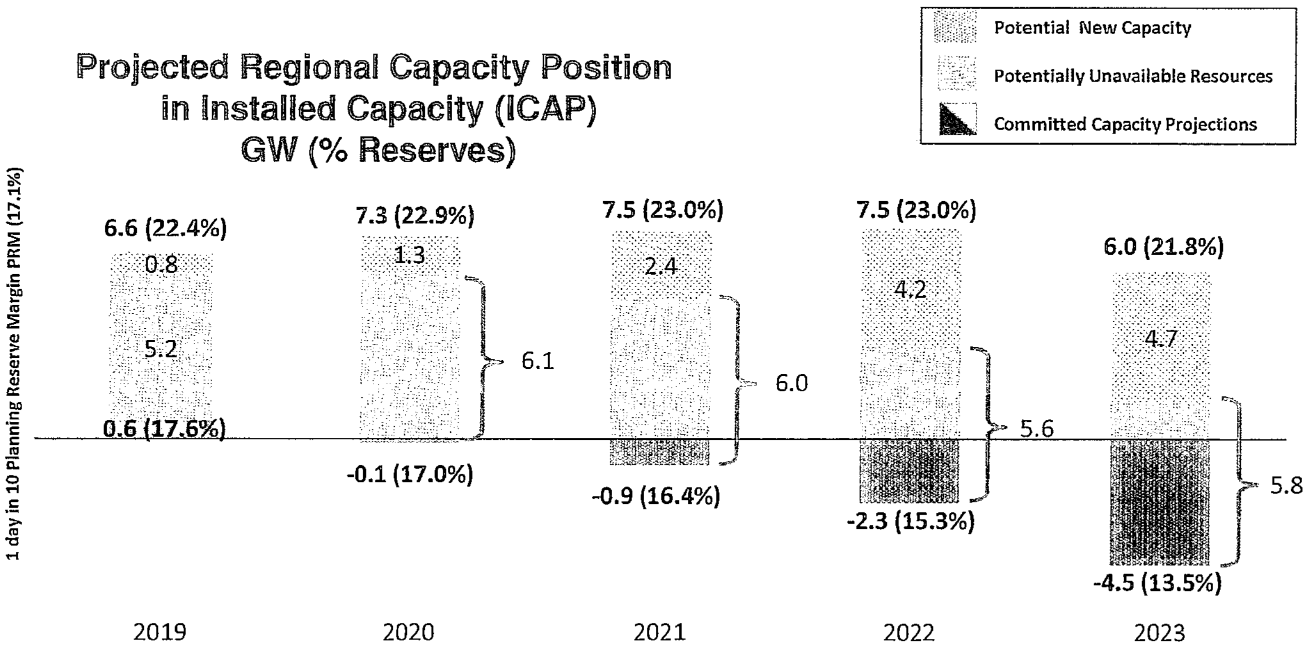
MISO Region is projected to have adequate resources to meet its Planning Reserve Requirement for 2019; continued action will be needed to ensure sufficient resources are available going forward

- The region is projected to have 0.6 GW to 6.6 GW resources in excess of the regional requirement, based on responses from over 97% of MISO load
- Beyond 2019, decrease in resource commitments could lead to more risk to resource adequacy than previously projected
  - Lower resource commitments are mainly focused in Zones 4 and 7
  - Fewer resource commitments lead to higher likelihood of using emergency resources
- Demand forecast continues to decrease similar to previous projections
  - 2019 summer peak forecasts decreased 1.5 GWs from 2017 projections
  - Regional 5 year growth rate is 0.3%, down from 0.5% last year

Understanding Resource Adequacy Requirements

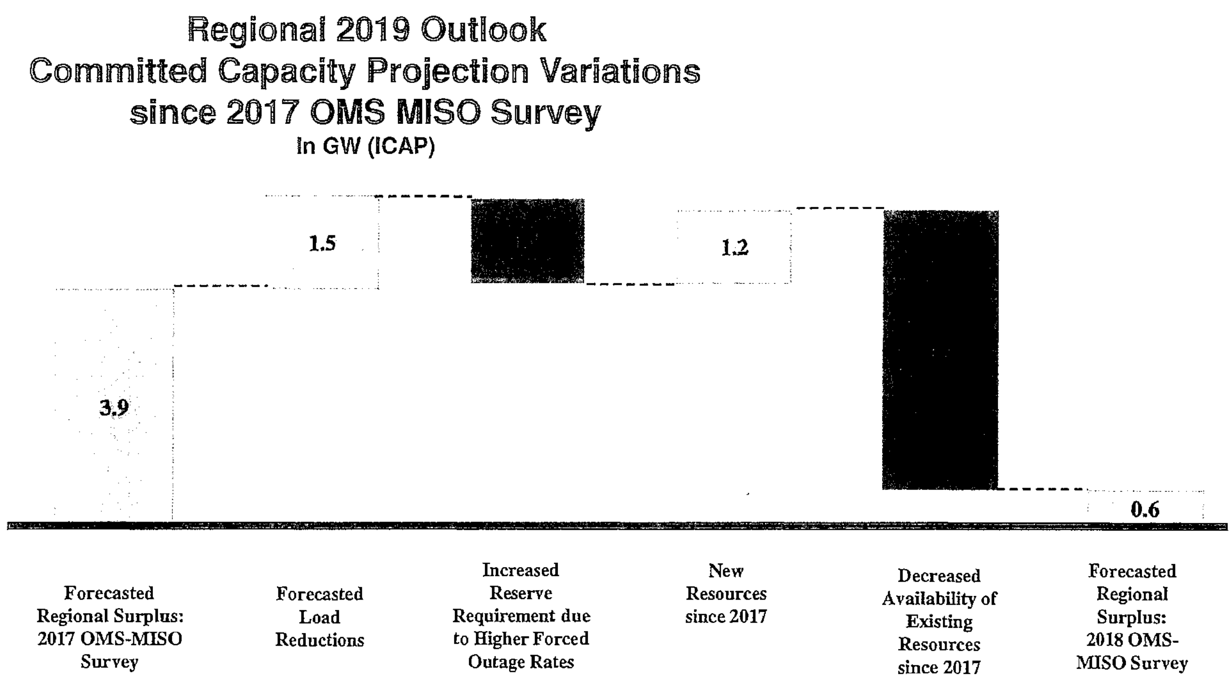
- Load serving entities within each zone must have sufficient resources to meet load and required reserves
- Surplus resources may be shared among load serving entities with resource shortages to meet reserve requirements

Existing resources, potential retirements, and new resources create a range of resource balances



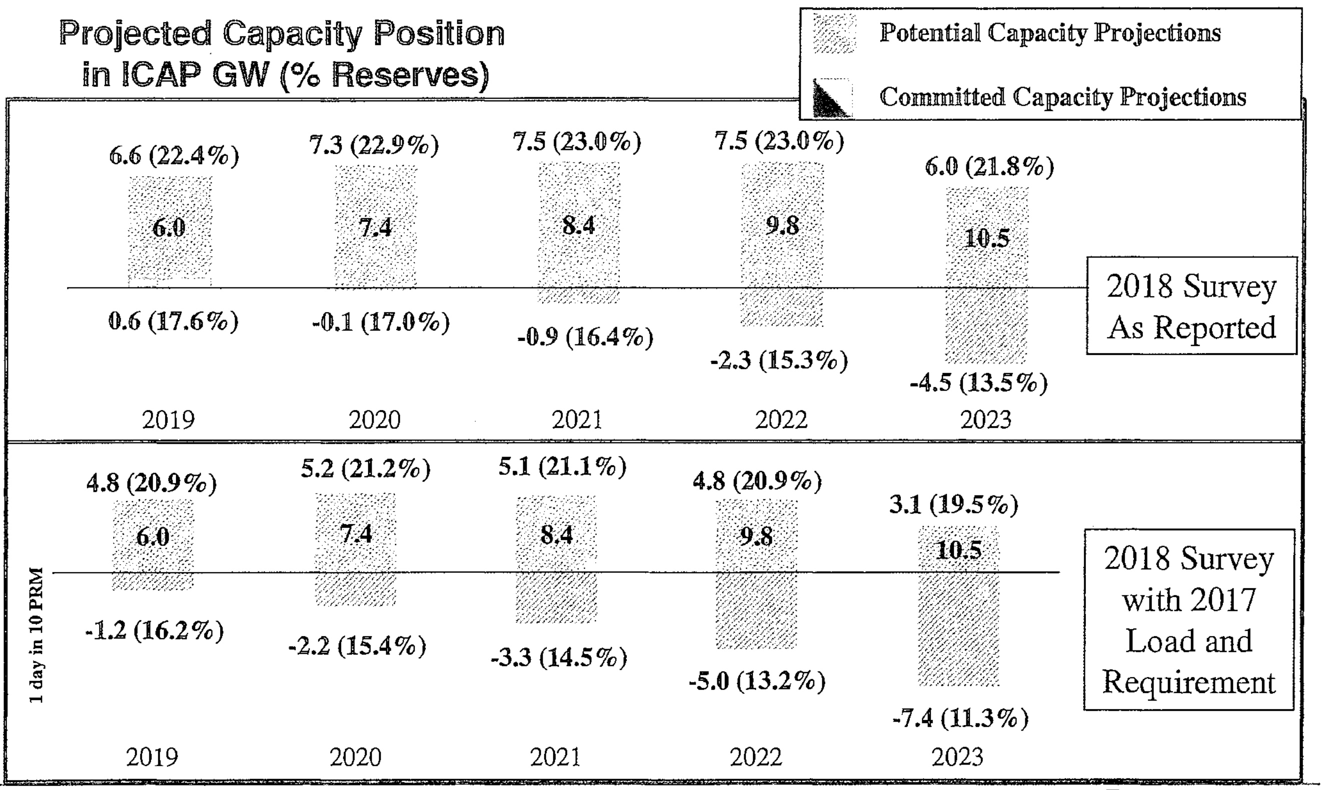
- Regional outlook includes projected constraints on capacity, including the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities, state commissions, and local regulators
- **Potential New Capacity** represents the capacity in the DPP study of the MISO Generator Interconnection Queue at their expected capacity credit and projected queue certainty factors (see slide 12), as of May 1, 2018
- **Potentially Unavailable Resources** includes potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint

Regional capacity balances decreased largely due to decreased availability of resources



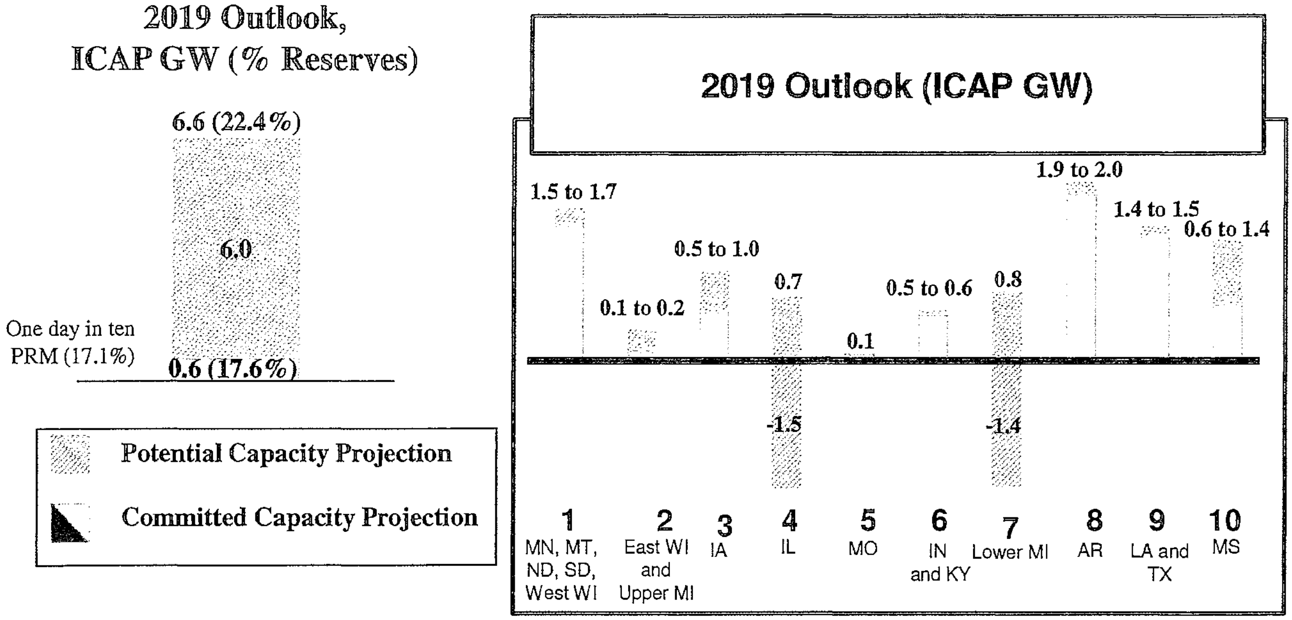
New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Decreased availability results from new retirements and potential retirements

Demand forecast variation creates risk for forward-looking resource adequacy projections



Potential Capacity includes potential new capacity and potentially unavailable resources

In 2019, regional surpluses are sufficient to cover areas with potential resource deficits



- The MPSC recently made a determination that the Michigan LSE's have adequate resources (owned or contracted) to meet projected resource adequacy through 2021, this aligns with the upper range of the OMS MISO survey projections for zone 7
- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint

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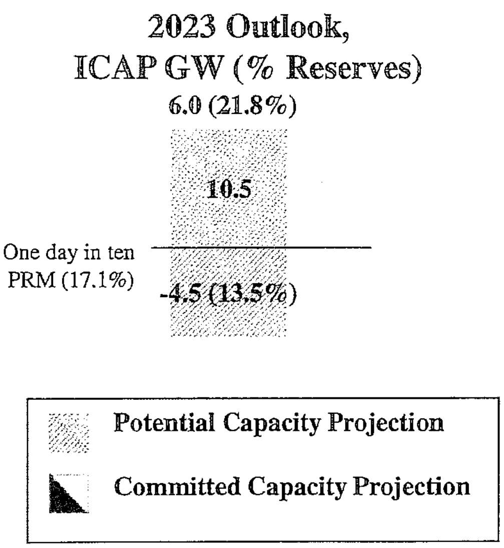
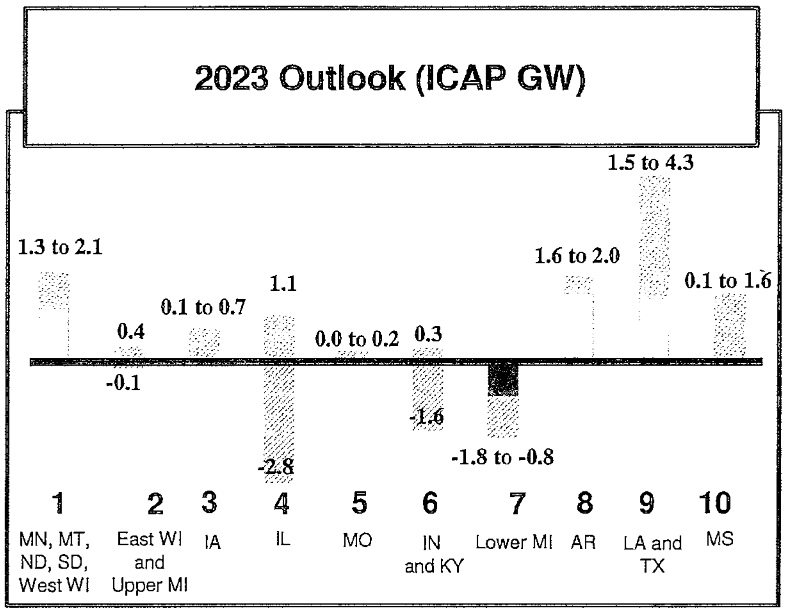
Continued focus on load growth variations and generation retirements will reduce uncertainty around future resource adequacy assessments





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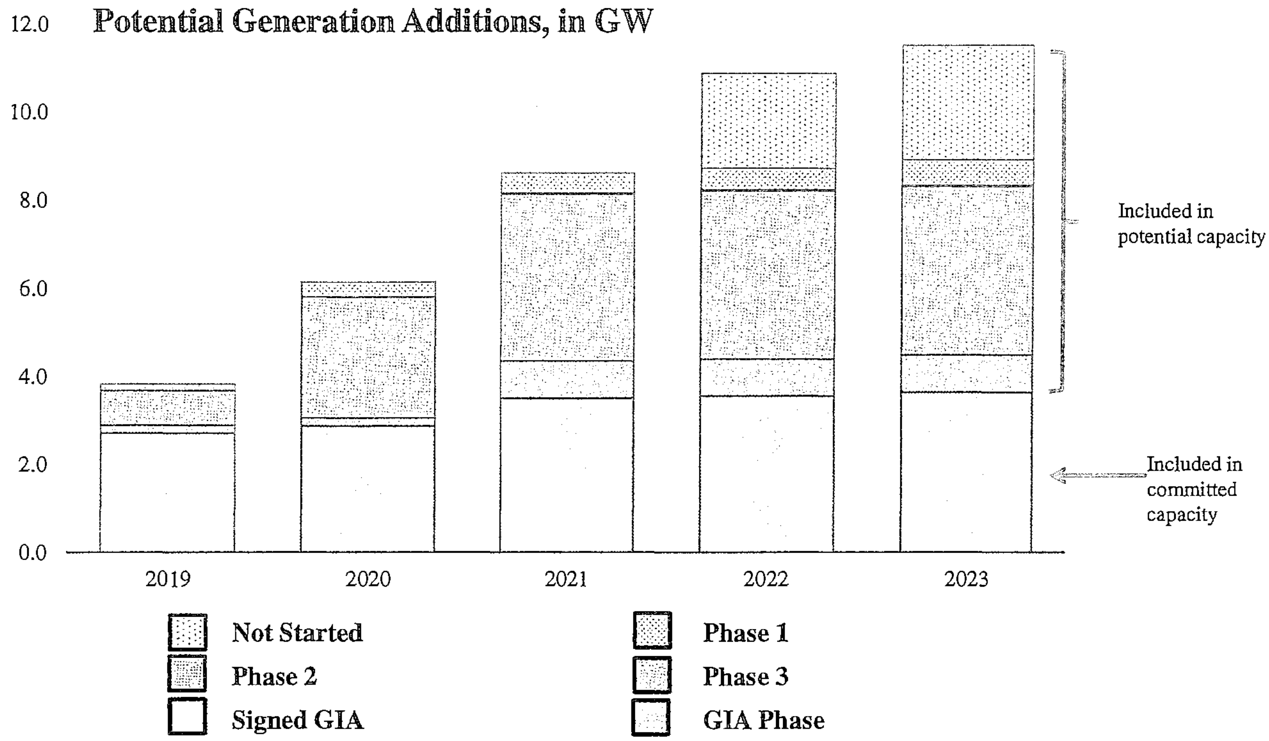
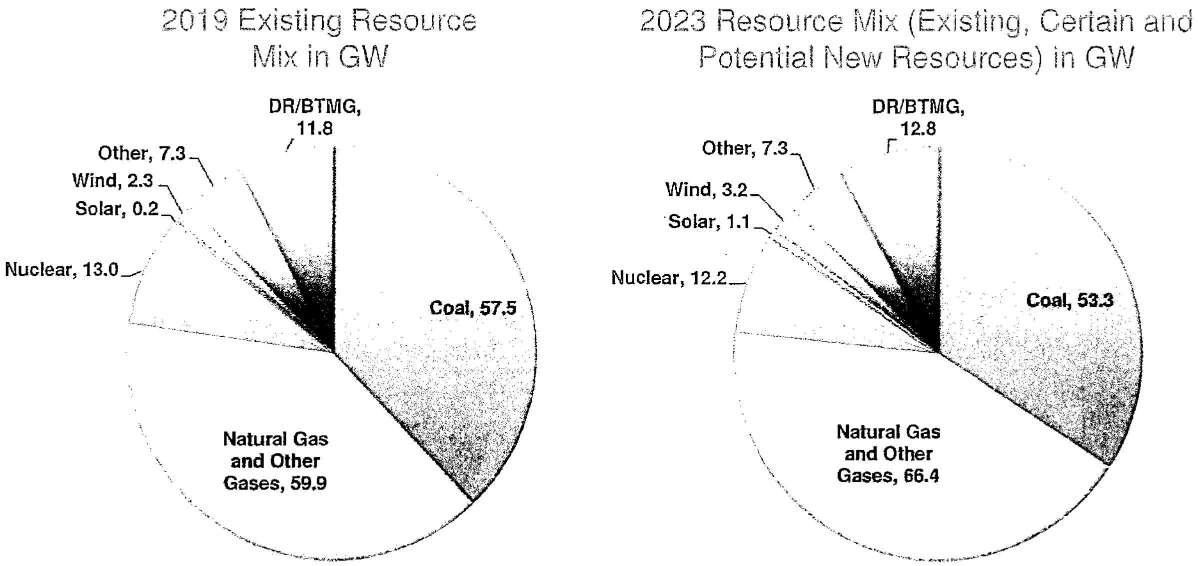
Future resource ranges will shift as planned generation interconnections are firmed up



- Potential new resources are represented at their expected capacity credit and projected queue certainty factors from slide 12

Forecasted resource mix changes continue to underpin a number of initiatives currently in the stakeholder process



- Existing wind and solar resources are at their expected capacity credit
- Potential new resources are represented at their expected capacity credit and projected queue certainty factors from slide 12

Appendix

MISO

2018 OMS MISO survey results consider new generator interconnections as potential capacity

Apply Capacity Credit

- Wind 15.6%
- Solar 50%
- All other 100%

Apply DPP Study Phase Weighting

- [illegible]
- [illegible]
- Phase 2 = 50% Non-Intermittent 25% Intermittent
- [illegible]
- [illegible]

Requested In-Service Date

If requested in-service date is prior to 2018 projects would be moved to their DPP study cycle end date unless an updated date is provided in the OMS MISO Survey

DPP Study Cycle Not Started

If the DPP Study Cycle hadn't started, then project requested in-service dates would be moved to their DPP study cycle end date plus 2 years, unless an updated date is provided in the OMS MISO Survey

- DPP = Definitive Planning Phase in the MISO generator interconnection queue
- DPP Study Phase Weighting is applied to recognize that as projects move through the queue process they generally become more certain
- In-service adjusted if the DPP Study Cycle Not Started to recognize that a project likely can't get capacity credit until at least the end of the DPP study cycle and additional 2 years to reflect expected GIA dates and possible construction timelines

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