Exhibit No.:	_______________
Issue(s):	OPC Recommendation
Witness/Type of Exhibit:	Mantle/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	EO-2018-0092

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EO-2018-0092

** **

Denotes Confidential Information
that has been redacted

March 13, 2018

PUBLIC VERSION

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan	)))	Case No. EO-2018-0092

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M. Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M. Mantle
Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 13th day of March 2018.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
JERENE A. BUCKMAN
My Commission Expires
August 23, 2021
Cole County
Commission #13754037

Jerene A. Buckman
Jerene A. Buckman
Notary Public

My Commission expires August 23, 2021.

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SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EO-2018-0092

Q. What is your name?

A. Lena M. Mantle.

Q. Who is your employer, what is your business address, and what is your job title?

A. I am employed by the Office of the Public Counsel ("OPC"). My business address is P.O. Box 2230, Jefferson City, Missouri 65102. I am a Senior Analyst for OPC.

Q. Are you the same Lena M. Mantle who testified in rebuttal in this case?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this testimony is to expand OPC's recommendation that the Commission reject the Empire District Electric Company's ("Empire") "Customer Savings Plan" as OPC recommended in its witnesses' rebuttal testimony to also recommend that the Commission find that, at this time, Empire's plan to build 800 megawatts of wind generation and retire its Asbury plant by 2019 is imprudent. I also respond to Renew Missouri Advocates ("Renew") witness James Owen's statement in his rebuttal testimony that Empire's plan would save customers' money and Division of Energy ("DE") witness Martin Hyman's statement in his rebuttal testimony that this plan would result in lower rates. I respond to Mr. Hyman's rebuttal testimony that there are no reliability concerns with Empire's plan. I also provide additional information in response to Staff witness John Rogers' rebuttal testimony regarding the selection criteria in the Commission's resource planning rules.

CHANGE IN OFFICE OF THE PUBLIC COUNSEL'S RECOMMENDATION

Q. What was OPC's recommendation to the Commission you presented in your rebuttal testimony?

A. My rebuttal testimony contains OPC's recommendation that the Commission not grant any of Empire's requests in this case. OPC made this recommendation because the actual impact Empire's "Customer Savings Plan" will have on Empire's Missouri retail customers' rates and the economy of southwest Missouri cannot, with any confidence, be determined. The actual impacts cannot be determined due to:

1) The vagueness of Empire's filing;
2) The significant changes in (a) the electric utility industry, (b) Southwest Power Pool ("SPP"), and (c) the economic environment that have occurred since Empire filed this case; and
3) The uncertainties around the future values of many of the inputs into Empire's analysis, and the risk these uncertainties put on Empire's customers.

Q. Can any of these actual impacts be determined with more confidence now?

A. No. To my knowledge, none of the uncertainties have been resolved. There now is additional information on the potential impact of the reduction in corporate income taxes. However, the impact of tax changes on the tax equity partners is still unknown. In addition, as I detail later in this testimony, OPC has learned of potential changes to SPP's markets that OPC believes are intended to reduce the frequency of negative prices in those markets. These proposed changes, if enacted, would create more uncertainty in both the revenues and production tax credits from energy generated by the wind turbines.

Q. Why has OPC expanded its recommendation to now include that the Commission find Empire's plan to build 800 megawatts of wind generation and retire its Asbury plant is imprudent?

A. Empire filed its application and testimony in this case on October 31, 2017, asking for an expedited schedule. OPC filed rebuttal testimony regarding this very complex $1.5 billion plan 99 days later. OPC has continued its investigation and analysis of this plan since that testimony was filed 35 days ago. As a result of that additional analysis, OPC now recommends that the Commission not only reject Empire's request in this case but also find that Empire's plan to build 800 megawatts of wind generation, and retire its Asbury plant is speculative, places too much risk on its customers, and, therefore, would be imprudent to implement. Empire's plan is not about meeting customers' requirements, now or in the future, in a least-cost manner. It is not driven by environmental regulations or legislative mandates. It is purely a business decision intended to enrich shareholders that could hypothetically, in ten to twenty years, provide benefits to the customers that would be funding the plan immediately. Schedule LMM-S-1 shows a chart of knowns and unknowns regarding Empire's proposal. A review of this charts quickly shows how this proposal is asymmetrical in favor of the shareholder who would recover the investment and a return on the proposal while the ratepayers would be shouldering the risks associated with almost doubling Empire's rate base and, perhaps, in five years start to see minimal benefits greater than the costs. This is explained in greater detail my testimony and in the rebuttal and surrebuttal testimony of OPC witnesses Dr. Geoff Marke, John S. Riley and John A. Robinett.

Q. Why is building wind generation as described in Empire's plan imprudent?

A. The wind generation is not needed to serve Empire's Missouri ratepayers. The effect of Empire's plan is for its shareholders and tax equity partner to be assured of a profit on a $1.5 billion investment in generating plants with virtually no risk when Empire already has all the generating resources it needs to serve its customers. Even under Empire's rosy analysis its customers would not receive significant annual net benefits (i.e. greater than $50 million) from the wind generation before 2030. Let me emphasize – the customers would see this benefit only if <u>everything</u> goes the way Empire is projecting it will. If a more normalized general rate case filing schedule is modeled and everything else remains the same as Empire is projecting, significant benefits to the customers will not be seen until 2032.

Empire's proposed plan contains no certainty that customers will receive any savings. In fact Empire's own analysis shows its customers would receive most of the benefits in the years 2033 through 2037. Empire is asking for a guarantee that Empire's shareholders receive millions of dollars of increased earnings from its retail customers starting as soon as 2020.[1] Any benefit to Empire's customers is very speculative while Empire is asking for regulatory certainty for its shareholders.

Q. Why is the timing of the benefits and costs important?

A. Empire modeled the costs and benefits of its plan based on projected costs, forecasted market prices, and forecasted fuel prices. As in any forecast, the projection is likely to be more accurate in the early years of the forecast than in the later years of a forecast. The farther into the future of a forecast, the less likely that it is accurate. In this case, the costs will be incurred in the near future making the actual costs incurred for the wind generation more likely to be accurate than the costs of the solar generation Empire's plan includes in 2031. Benefits greater than costs are not projected to occur until many years in the planning future meaning that these benefits are unlikely to be as modeled. They may be higher. They may be lower but they are very uncertain.

Q. Why is Empire's proposed regulatory treatment for the premature retirement of Asbury imprudent?

[1] While Empire has not stated when it would file for a rate increase to include the cost of the wind generation, because of the large investment for the wind it is likely to occur in 2020.

A. Retiring Asbury in 2019 is imprudent. As described in OPC witness Robinett's rebuttal testimony, Asbury underwent significant modifications in 2014 to retrofit and upgrade of the steam turbine as well as install mercury, sulfur dioxide, and particulate matter emissions controls.[2] This plant is now running more efficiently than it did in 2008.[3] Empire estimated that these improvements would extend the life of Asbury by 5 years, from 2030 - to 2035. New rates incorporating recovery of these costs through 2035 became effective on July 26, 2015. Now just less than three years later, Empire has determined that, because there may be a need for additional investment in Asbury by 2020,[4] and because the operations and maintenance costs at Asbury result in it being marginally economical in the SPP market in some hours of the year, Asbury should be retired in 2019, well before 2035.

Q. Is Empire proposing to retire Asbury because it is Empire's most expensive generating plant to run?

A. No. In Empire's last general rate case, Case No. ER-2016-0023, the Commission Staff's fuel run modeling showed that, given the inputs into the production cost model, including normalized SPP market and fuel prices and the purchased power costs, Asbury generated the most energy of all of Empire's resources. Attached as Schedule LMM-S-2 to this testimony is a summary of the Staff fuel run that includes Empire's newer Riverton combined cycle plant. Because of the costs, some plants were not even dispatched. Empire's wind purchased power agreements, even though energy from them was more costly than energy from Asbury, were dispatched because these agreements state that Empire must pay for the energy that they generate whether Empire needs the energy at that time or not.

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[2] Robinett rebuttal, pg. 5:8-9J
[3] Id, pg. 7
[4] The need for this additional investment was known when the decision was made to add the emission controls and upgrade the steam turbine.

Q. Does Asbury have operating characteristics that make it more attractive as a source of energy than Empire's wind contracts?

A. Yes. In addition to its fuel costs being lower than purchased power prices, Asbury can generate electricity when called upon.[5] There is some coal kept on site that increases its availability. Forced outages may occur but typically Asbury will be available during the hottest months of the year when wind generation is providing the least amount of energy.

Q. How is Empire asking the Commission to treat Asbury for ratemaking purposes in this case?

A. Empire is seeking approval from the Commission to create a regulatory asset to allow Empire to recover both a return of and a return on Empire's Asbury plant balances as of the date it is retired, which Empire projects to be approximately April 2019. It is my understanding that Empire will then request in its next rate case that it be allowed to recover the undepreciated cost of Asbury from its customers over the next 30 years.

Q. Is Empire's proposed rate making treatment for Empire prematurely retiring Asbury prudent?

A. No it is not. If Empire determines that Asbury should be retired before 2035, Empire's customers should not be required to provide Empire recovery of its investment in the plant. Asbury would no longer be fully operational and used for service, or used and useful, and would no longer provide any electrical energy or capacity for Empire's customers' benefit. By the Commission authorizing Empire to receive a return on its investment in Asbury since it began operating in 1970, a return above the long-term interest rate, Empire's shareholders have been compensated for this type of risk.

[5] Taking into account ramp up time and minimum operating constraints

COST OF THIS PLAN TO EMPIRE'S CUSTOMERS

Q. Renew witness James Owen states in his rebuttal testimony that Empire's plan will save customers money.[6] Division of Energy witness Martin Hyman states in his rebuttal testimony Empire's customers will see lower rates.[7] What is your response to these statements?

A. It is yet to be determined whether or not customers would actually save money if Empire implements its plan. What is certain is that this plan will cost customers. Empire is asking for assurances that, regardless of the revenues that may be generated by selling wind energy on the SPP market, the Commission require its customers to pay for both Empire's investment in building the wind generation and a return on that wind generation investment.

Q. What has Empire estimated the increase in its revenue requirement as a result of adding the wind generation as described in Empire's plan to be?

A. According to the work papers of Empire witness Greg Macias, Empire's revenue requirement increase attributable to the wind generation in 2020 is $133 million.

Q. How would that impact an Empire residential customer's bill?

A. Everything else being held equal and assuming an equal increase across jurisdictions and customer classes, this increase in revenue requirement would be approximately 26%.[8] This equates to an increase to a residential customer using 1,000 kWh a month of $37.38 a month in the summer months and $34.84 a month in the non-summer months, for a total annual increase of $428.24.

Q. Would this increase be off-set by revenues Empire receives from energy from this wind generation that it sells on the SPP markets?

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[6] Owens rebuttal, page 4:9
[7] Hyman rebuttal, page 7:7-8
[8] Using the Empire total company actual annual residential, commercial, and industrial customer revenues for 12-months ending September 2017 as provided in Empire's FAC quarterly surveillance report BFQR-2018-0213

A. It would. However, the magnitude of that revenue is very uncertain, and would not be known until it is actually received. However, the cost would be incurred, and Empire's plan is for its customers to not only pay the costs of the wind generation, but also provide a return to its shareholders, regardless of what revenues it receives.

Q. Since you filed rebuttal testimony has anything occurred that makes the revenues estimated in Empire's analysis even more uncertain?

A. Yes. As described in Missouri Energy Consumer's Group ("MECG") witness Greg Meyer's testimony and my rebuttal testimony, SPP has become concerned regarding the number of hours with negative prices. As Mr. Meyer explains, "due to the presence of the [production tax credits ("PTCs")], and recognizing that PTCs are paid on the basis of MWh's generated, owners of wind generation are willing to pay negative prices to SPP in order to maximize the value of the PTC." [9]

Since filing rebuttal testimony, I became aware of the SPP Revision Request 272 Report that I have attached to this testimony as Schedule LMM-S-3 which I believe is a SPP attempt to resolve this problem. In this revision report, SPP states:

> Collections of [Non-Dispatchable Variable Energy Resources ("NDVERs")] are generally located in the same region, however it is often necessary to redispatch many Resources ([Dispatchable Variable Energy Resources ("DVERs")] and others with potentially lower shift factors) around them in order to solve constraints, leading to higher congestion costs for the market. Additionally, SPP has observed NDVERs reacting to [Locational Market Price ("LMP")] signals - dropping offline when the LMP drops and responding to increased LMPs by generating at the same prior output; although by definition, NDVERs are not capable of being incrementally dispatched by the Transmission Provider. When this price-following behavior from NDVERs occurs, the subsequent market redispatch and pricing are inefficient, due to the assumption that NDVERs are not capable of dispatching and reacting to price.

In addition, SPP states in this report that:

[9] Meyer Rebuttal, page 16:11-14

> The price-following behavior of NDVERs also present reliability and operational challenges when NDVERs suddenly drop offline and then return to follow an increase in LMP as more relief may be realized than was requested . . .

In this revision request SPP is proposing that energy resources that previously SPP had taken energy from regardless of the price or the need for energy, be redefined as a dispatchable resource. This means that SPP would have the ability to tell a wind generator that SPP would not take the energy from the wind generator's wind turbines.

Q. What would be the impact of such a revision to Empire's plan?

A. It is my understanding that in its analysis of its plan, Empire assumed that when weather conditions were favorable, its wind generation would automatically sell into the market and the project would receive a production tax credit. If this SPP revision is adopted, Empire should not assume that SPP will automatically buy all the energy Empire's wind turbines would generate regardless of whether the energy was needed or whether it would cause reliability concerns. This revision would likely reduce Empire's revenues from SPP that Empire uses to offset its revenue requirement increase required for its proposed additional wind generation.

Q. Could changing wind generation from being a non-dispatchable variable energy resource to a dispatchable energy resource affect more than just Empire's revenues from SPP?

A. Yes. It could reduce the amount of production tax credits, which are based on the energy generated by wind. According to Empire's direct testimony, payments to the equity tax partner(s) in years six through ten are dependent upon the production tax credits received in years one through five. Lower production tax credits in years one through five will result in higher payments from Empire to its tax equity partner(s) in years six through ten. This in turn reduces the cost-effectiveness of the plan to the customers, because Empire ultimately intends to recover these payments from its customers in their rates.

RELIABILITY CONCERNS

Q. Division of Energy witness Martin Hymen states that there are no reliability concerns related to Empire's plan.[10] Do you agree?

A. No. Mr. Hyman bases his belief on Empire's testimony. However, OPC asked in its data request 8018 for Empire to provide its analysis which supports Empire's assertion that its plan "provide[s] the non-intermittent capacity to provide our customers stable energy resources."[11] Empire's response follows:

> The Southwest Power Pool (SPP) requires Empire to maintain a capacity margin of 12% and a reserve margin of 13.6% to service our native load. Assuming that Asbury is retired in 2019 and the wind projects are operational in 2020, Empire will be able to meet all of SPP's requirements in 2019 and beyond.

Q. Does this response support Mr. Hyman's belief that there are no reliability concerns related to Empire's plan?

A. No, it does not. This response merely states that Empire has enough capacity to meet the SPP capacity margin. What this means is that Empire has enough accredited capacity to meet its peak load plus a margin. However, reliability is more than just the peak load. Reliability is 8,760 hours of the year. Because wind is intermittent (i.e. energy is only generated when the wind blows), it cannot be depended on for every hour of the year. Empire provided no analysis to show that its non-intermittent capacity could provide reliable energy for its customers.

PLAN SELECTION CRITERION

Q. Were you on the Commission's Staff when the Commission's Chapter 22 Electric Utility Resource Planning rules were written?

[10] Page 4:4
[11] Mertens Direct, page 11

A. Yes. I was on the Staff team that developed the original Electric Utility Resource Planning Chapter 22 that Staff presented to the Commission in 1992, and I oversaw the revisions that Staff proposed to the Commission in 2010.

Q. When these Chapter 22 rules were being developed, to your knowledge, did anyone envision that a load serving electric utility would build resources, not because its customers needed additional resources, but because it was attempting to generate more net revenue from an energy market?

A. No. Chapter 22 originally was written before the Federal Energy Regulatory Commission began to promote wholesale markets. The only reason for electric utilities to build generation was to meet their customer's needs. Because adding generation is "lumpy" there were times when a utility built more generation than it needed. In these instances when a utility had excess capacity or energy it would enter into a bilateral contracts with neighboring utilities to sell the excess until that capacity and energy was needed for its own customers.

Q. Staff witness John Rogers testifies in his rebuttal testimony that the Commission's resource planning rule 4 CSR 240-22.010 requires present value of revenue requirement ("PVRR") to be the primary selection criteria for an electric utility to choose its preferred resource plan. Were you a part of the discussions regarding what the primary selection criterion should be for a preferred resource plan?

A. Yes.

Q. Was there discussion in the development of Chapter 22 regarding the selection criteria for an electric utility's preferred resource plan?

A. Yes. There was much discussion regarding whether or not Chapter 22 should state a controlling criterion for choosing a preferred resource plan and, if so, what that criterion should be. However, there was agreement that, if such a criterion was chosen, it should only be listed as the "primary" criterion which would allow the electric utility some flexibility to choose a preferred plan. Specifically, different resource types, both supply- and demand-side, have different unknowns and risks. With the rule only prescribing a "primary" criterion instead of a single definite criterion, the utility could choose a plan that may not necessarily maximize the chosen criterion, but have other characteristics such as greater certainty in costs and technology, greater reliability, and lower year-to-year impact on rates that would result in a better resource plan.

For example, in his rebuttal testimony Mr. Rogers provides that the results of Empire's own analysis only shows a difference of $22 million between the 20-year PVRR of its proposed plan and the same plan with Empire's Asbury plant continuing to operate until 2035. This $22 million amounts to less than a 0.3% difference in PVRRs between these two scenarios. So, in essence, there is no difference in the PVRR of these two plans. Before determining which of the two plans to go forward with, the unknowns and risks of the two plans, along with the potential impacts - monetary, safety, and reliability - of the unknowns should be carefully considered before determining which plan is the better plan.

Q. What was the difference in the PVRRs of Empire's current preferred resource plan and the plan Empire is seeking for the Commission to approve in this case?

A. Based on Empire's analysis, the difference between Empire's current preferred plan and the plan Empire is requesting special regulatory treatment of in this case is $325 million over 20 years. This $325 million is just a 4% change in PVRR, well within the margin of modelling error. As I described in my rebuttal testimony, using a more reasonable estimate of when the customers would actually see reductions in revenue requirement, the change in PVRR is $223 million which is less than a 3% change in PVRR.

While these numbers ($325 million and $223 million) seem large, other things need to be taken into account. As shown in Schedule LMM-S-1 and described in rebuttal and surrebuttal testimonies of OPC witnesses, Staff witness Mr. Rogers, and MECG witness Mr. Meyer, there are many unknowns regarding Empire's plan. Using different assumptions regarding many of these unknowns could change which of these two plans actually has the lower PVRR.

For these two plans, the cost to Empire's shareholders is the opportunity cost of the return on investment that the shareholders from the proposed plan over the current plan. So in essence, if this plan is approved, there is no cost to Empire's shareholders. Empire's customers would bear the burden of the cost of building the wind generation, of paying for a plant that has been prematurely retired, and for energy efficiency programs that will not delay the need for any additional generation and increase costs to non-participants while benefiting participants and Empire's shareholders.

According to Empire's own analysis, its customers will not see any benefits from the wind generation until 2023, and it estimates that benefit in 2023 to be a minimal, $4 million. If revenues from market prices are as little as 3% lower than what Empire forecasts, there would be no benefit for Empire's customers until 2024. However, by Empire's own analysis, by the end of 2024, Empire's retail customers would have paid over $650 million through revenue requirement increases for this generation.[12]

Q. You have testified that you were on the Staff team that developed Chapter 22. How long have you worked with electric utility resource planning?

A. Except for the 18 months between when I retired from Staff and began working at OPC, I have been involved in resource planning for at least 28 years.

[12] Assumes changes in revenue requirement in 2020 and 2024

Q. In that time are you aware of any time an investor-owned electric utility built generation for the explicit purpose of making off-system sales?

A. I am not aware of any such instance for a Missouri investor-owned electric utility. There have been instances where affiliates of Missouri investor-owned electric utilities have built generation to make off-system sales. These generating units have since been sold. However, I am not aware of any investor-owned electric utility in Missouri building generation with the explicit expectation that it would recover the cost of the generation from the customers and return the revenues from the sales to the customers.

Q. How could Commission approval of this request change resource planning for Missouri electric utilities?

A. If this Commission allows this, there will be no need for resource planning. Building of generation will be bifurcated from load just as the load requirements of Empire's customers have nothing to do with this request. The electric utilities will rely their regional transmission organization ("RTO") to meet the energy requirements of their customers, with no concern about how or when their customers use electricity. Instead of customers' load being used to determine when and what generation to build; generation will be built based on whether or not the electric utility management believes it can achieve more revenue from sale of energy[13] from the generation resource than it believes the resource will cost and the minimum necessary to meet the capacity requirements of the RTO. The customers' role would be to provide certainty for the shareholders to receive both a return of and a return on the utility's capital investment and, perhaps, if the utility management guesses correctly, the customers may receive a little benefit from the RTO to offset the cost of energy.

[13] The utility would also receive revenue for capacity if it is a member of a RTO with a capacity market.

Q. Has Empire's board of directors approved of the plan Empire is requesting that the Commission approve in this case?

A. No. According to Empire's January 5, 2018 response to OPC data request 8014:

> No formal presentations have been made to the Company at this time. While the Company Board of Directors has been apprised of the regulatory filing progress via verbal updates, no decisions are pending for Board approval at this time. Once regulators approve the Customer Savings Plan [("CSP")] or the Company enters into material contracts related to the CSP, Board of Directors approval to proceed will be sought.

Q. Why not?

A. I do not know. From this response, it seems as if the responsibilities of Empire's Board of Directors is limited to carrying out the plans of Algonquin. In this case, the Board of Directors would be asked to implement the "customer savings" plan to use Missourians to provide earnings to its Algonquin's shareholders. This plan would take money out of the pockets of hardworking Missourians of all income levels and give it to Algonquin's shareholders scattered all over the world.

Q. Would you summarize your testimony?

A. Retail utility rates should reflect only the costs that are necessary for the utility to provide safe, adequate, and reliable utility service. Empire has not shown that its plan is necessary for it to provide safe, adequate, or reliable service. Given the uncertainties of Empire's plan, the large magnitude of Empire's proposed investment, and that Empire does not need the wind generation to meet its customers' energy needs, the Commission should find Empire's plan imprudent. This plan is about Empire's desire to use its customers to guarantee a large investment to increase Empire's shareholders' return with a speculation that, in five to ten years down the road, Empire's customers may realize benefits greater than their costs.

In addition, if the Commission approves Empire's request, it sets a precedent. If Empire, in 2022 decides there is a new resource that better "beats the market" and creates some analysis that shows this is a possibility, will it come ask for Commission approval to "retire" this 800 MW of wind generation, charge the customers for the wind generation and then also charge the customers for the new technology? This is exactly what it is asking in this case a mere three years after it asked the Commission for cost recovery of its improvements to its Asbury plant.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Empire District Electric Company “Customer Savings Plan”
Partial List

<table>
<tr><th>Knowns</th><th>Unknowns</th></tr>
<tr><td>
Equity partners receive a return of and on their investment

Empire shareholders receive a return of and on their investment

Empire customers depend on SPP for reliable energy

Revenue requirement will increase

Benefits are based largely on saving in the later years

Less diversity in Empire’s generation resources

Massive one-time investment will diminish Empire’s ability to

take advantage of emerging energy technologies including wind
improve distribution system
make other capital investments

No new generation is needed to meet customers’ needs
</td><td>
Identity of Tax Equity (“TE”) Partner

Structure of the specific tax equity partnership agreement

How much of capital costs TE partner will provide ($560 mil - $840 mil)
Hedge price Empire customers pay the TE partner in years 1-5
TE’s partner’s share of cash distribution during years 6-10
Regulatory treatment of hedge price Empire pays TE partner in years 1-5

SPP market prices

Impact of wind generation added by other SPP members
Impact of retirement of fossil fuel plants
Changes in SPP market rules
Additional member resources

Construction of wind turbines

Contractor(s)
Location(s)
Technology to be installed
Cost
Impact of tariffs on imported steel
Date installation would be complete
Construction risks
Availability of materials
Availability of construction crew
Weather

Impact on wildlife (birds, bats, etc.)
</td></tr>
<tr><th>Knowns</th><th>Unknowns (continued)</th></tr>
</table>

	Fossil fuel costs • Natural gas • Coal • Transportation Production tax Credits • Date installation complete • Actual turbine capacity factors • SPP market rules regarding dispatchability/curtailment • Weather Turbine risks • Maintenance issues • Under-performance • Aging of components • Weather Wind technology advancement • Obsolescence • Cost of repowering Transmission costs Changes in environmental regulations • Fossil fuel plants • Wind turbine sites Impact on economy of Southwest Missouri • Electric rates • Bill volatility • Jobs • Property taxes

EO-2018-0092

Mantle Surrebuttal Testimony

Schedule LMM-S-2

has been deemed

Confidential in its entirety

Revision Request Recommendation Report

RR #: 272	**Date:** 2/6/2018
RR Title: NDVER to DVER Conversion	
SUBMITTER INFORMATION	
Submitter Name: Erin Cathey on behalf of SPP	**Company:** Southwest Power Pool
Email: ecathey@spp.org	**Phone:** 501.590.8298
EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION	
OBJECTIVE OF REVISION	

Objectives of Revision Request:
Describe the problem/issue this revision request will resolve.

SPP proposes in this revision request to require that, after a two year transition period, all Variable Energy Resources registered as Non-Dispatchable Variable Energy Resources be required to register as Dispatchable Variable Energy Resources unless they are a Qualified Facility exercising their rights under the Public Utility Regulatory Policies Act of 1978 (PURPA).

Non-Dispatchable Variable Energy Resources in SPP's market create market inefficiencies and reliability risks that SPP resources and systems must mitigated.

1) Market Efficiency: Collections of NDVERs are generally located in the same region, however it is often necessary to redispatch many Resources (DVERs and others with potentially lower shift factors) around them in order to solve constraints, leading to higher congestion costs for the market. Additionally, SPP has observed NDVERs reacting to LMP signals - dropping offline when the LMP drops and responding to increased LMPs by generating at the same prior output; although by definition, NDVERs are not capable of being incrementally dispatched by the Transmission Provider. When this price-following behavior from NDVERs occurs, the subsequent market redispatch and pricing are inefficient, due to the assumption that NDVERs are not capable of dispatching and reacting to price. Additionally, SPP may OOME NDVERs today. However, the issuance of an OOME is less precise than the systematic redispatch provided by the market when resources are dispatchable. This imprecision results in either too much or too little redispatch being provided requiring other market and reliability mechanisms to make up the difference.
2) Reliability: The price-following behavior of NDVERs also present reliability and operational challenges when NDVERs suddenly drop offline and then return to follow an increase in LMP as more relief may be realized than was requested by the SCED solution; SCED is unable to effectively clear energy and cover regulation when NDVERs behave in this manner. This behavior results in the SPP BA having to manually manage the additional lost output with regulation, putting the Reliability Coordinator in a position to possibly issue an OOME to the NDVERs who are responding to LMP changes in order to mitigate flowgates becoming unstable from the unexpected oscillations caused by NDVERs that follow price. Additionally, NDVERs make up a large majority of the Resources to which OOMEs are issued. The need to issue an OOME inherently represents an actual reliability issue that has risen to the attention of the RC and requires the RC to take action to maintain reliability. Although these reliability issues are manageable, converting NDVERs to DVERs would remove the associated reliability risks.

In the 2015 ASOM Report, the SPP MMU stated their concern with Non-Dispatchable Variable Energy Resources due to their adverse impact on market prices. The SPP MMU stated that when prices are depressed in high wind production regions, NDVERs have an adverse impact on prices in two ways. Some resources chase price, ignoring the system dispatch and self-dispatching to a lower level in an attempt to avoid the cost associated with producing when prices are very low. This behavior at times causes unexpected volatility on the system and distorts market prices. The alternative behavior is for these NDVER units to continue to produce as expected even when prices are below what would be an appropriate market clearing price. Both cases result in sub-optimal market results. The SPP MMU recommended SPP transition NDVER Resources to DVER status to lessen the negative impact of such resources on the market. Work to respond the MMU's recommendation has been tracked via both MOPC and MWG action items.

Describe the benefits that will be realized from this revision.

- Increased reliability realized through collective dispatchable Resources mitigating multiple constraints simultaneously
- Increased economic efficiency through reduction of manual Out-of-Merit Energy (OOME) instructions
- Reduction of price volatility (reliability and economic benefit)
- Having more VERs be controllable by the market and not subject only to variable fuel and external control behaviors leads to less pricing uncertainty as a result of:
    - Reduction of ramp scarcity events by having NDVERs controllable within SCED
    - Further optimization of quick start Resource needs by having a larger set of Resources that are under SCED control
    - Increased pricing convergence between Day Ahead and Real-Time due to larger set of controllable Resources in RT
    - Further potential optimization of Operating Reserves with potentially more VERs participating in the offering of certain ancillary services. If they convert, they will be controllable and may qualify for REG DN
    - Increased reliability by reducing NDVER generation oscillation
    - Market efficiencies are gained by adding dispatchable generation to resolve congestion in the load pocket, rather than redispatching less effective generation to protect the NDVER output. This has the potential to reduce the congestion costs from less effective generation redispatch

SPP STAFF ASSESSMENT

IMPACT
Will the revision result in system changes ☒ **No** ☐ **Yes** **Summarize changes:** **Will the revision result in process changes?** ☒ **No** ☐ **Yes** **Summarize changes:**
Is an Impact Assessment required? ☒ **No** ☐ **Yes** **If no, explain:**

Estimated Cost: N/A	**Estimated Duration:** N/A
Primary Working Group Score/Priority: N/A	

SPP DOCUMENTS IMPACTED		
☒ **Market Protocols**	**Protocol Section(s):** 1, 6.1.8, 6.1.9	**Protocol Version:** 54a
☐ **Operating Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Planning Criteria**	**Criteria Section(s):**	**Criteria Date:**
☒ **Tariff**	**Tariff Section(s):** 1.1, 2.2	
☐ **Business Practice**	**Business Practice Number:**	
☐ **Integrated Transmission Planning (ITP) Manual**	**Section(s):**	
☐ **Revision Request Process**	**Section(s):**	
☐ **Minimum Transmission Design Standards for Competitive Upgrades (MTDS)**	**Section(s):**	
☐ **Reliability Coordinator and Balancing Authority Data Specifications (RDS)**	**Section(s):**	
☐ **SPP Communications Protocols**	**Section(s):**	

WORKING GROUP REVIEWS AND RECOMMENDATIONS List Primary and any Secondary/Impacted WG Recommendations as appropriate	
Primary Working Group: MWG	**Date:** 2/6/2018 **Action Taken:** Approved **Abstained:** CUS **Opposed:** KEPCO, WR, NPPD, Tenaska, OPPD, AECC, KCPL

Reason for Opposition:

<u>John Varnell (Tenaska)</u> – I voted no because it has no prevision to help type I & II's to get wavers except from FERC if they cannot meet the requirements.

<u>Jim Flucke (KCPL)</u> – KCP&L voted in opposition to RR272 NDVER to DVER Conversion. KCP&L believes that the mandatory conversion of all Non-Dispatchable Variable Energy Resources is unnecessary and potentially places an undue financial burden on market participants. This financial burden will be most immediate and severe on Variable Energy Resources utilizing type 1 and type 2 wind turbines but also on those market participants with "take or pay" contracts for the power generated by Variable Energy Resources. The intent of the exception granted in the protocols for wind facilities "with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012" was precisely to avoid the costly conversion of older wind facilities to be capable of dispatchability and also to avoid the legal issues associated with renegotiating power purchase agreements.

Secondary Working Group: ORWG	**Date:** 3/1/2018 **Action Taken:** Approved **Opposed:** NPPD, KCPL, Empire District

Reasons for Opposition:

<u>Ron Gunderson (NPPD)</u> – NPPD voted against RR272 because of its potential to harm market participants by exposing them to curtailment costs associated with economic curtailments that were not required when they entered into PPA contracts. I do not have a reliability based concern with RR272 unless current NDVERS register as a DVER as required by this RR and do not perform as expected due to physical limitations with the facility.

RR272 effectively abrogates all NDVER PPA contracts, except for qualifying facilities, by undermining the grandfathered non-dispatchable status over older wind farms upon which their supply contracts were based. RR272 throws NDVER owners/buyers "under the bus" by financially exposing them to "economic dispatch" of which neither contract accounted for nor for which the unit was operationally constructed. RR272 forces NDVER conversion costs upon the Asset Owners which did not anticipate the cost when they were integrated with SPP. SPP is effectively adding another interconnection requirement years after the fact, which does not seem just or reasonable.

Last and perhaps the most import factor not considered by RR272 is SPP's market reputation. NDVERs were a condition of several MPs agreeing to transition from EIS to IM. If we go back on our word, will other MPs lose confidence in the stability of SPP tariff grandfathering and agreements made to prospective Balancing Authorities, Asset Owners, and Market Participants considering the benefits of join SPP as a stable settlement & market platform?

<u>Jay Patel (KCPL)</u> – KCP&L voted in opposition to RR272 NDVER to DVER Conversion. KCP&L believes that the mandatory conversion of all Non-Dispatchable Variable Energy Resources is unnecessary and potentially places an undue financial burden on market participants. This financial burden will be most immediate and severe on Variable Energy Resources utilizing type 1 and type 2 wind turbines but also on those market participants with "take or pay" contracts for the power generated by Variable Energy Resources. The intent of the exception granted in the protocols for wind facilities "with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012" was precisely to avoid the costly conversion of older wind facilities to be capable of dispatchability and also to avoid the legal issues associated with renegotiating power purchase agreements.

<u>David Pham (Empire District)</u> – I have no concern about reliability on this RR. But the contracts that members had that would impact the economic significantly; in addition, who is paying for all the systems and upgrades so that these grand-fathered farms can follow dispatch instructions. As far as operating the wind farms reliably today, RC can always curtail the wind farms to control them.

Secondary Working Group: RTWG	**Date:** 3/22/2018 **Action Taken:** **Abstained:** **Opposed:**

Reasons for Opposition:	
MOPC	**Date:** 4/10/2018 **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
BOD/Member Committee	**Date:** 4/24/2018 **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
COMMENTS	
Comment Author: Ronald Thompson on behalf of NPPD	
Date Comments Submitted: 2/1/2018	

Description of Comments:

NPPD has concerns with RR272

See below for NPPD comments related to RR272:

- SPP has stated that conversion of the NDVER to DVER units would have a positive impact on market efficiencies. With a potential of market benefits, we believe it to be short sighted to not address the cost impacts of such a conversion on the member utilities. This would include a process to determine the level of cost by that Entity and have the market compensate the costs.
- There are some Resources not designed to move every 5 minutes. Example would be Type 1 and Type 2 wind turbines. Converting these types of Wind Turbines would likely result in additional maintenance costs and increased risk of turbine failures. These costs and risks will be borne by the member or developer with potentially no chance of cost recovery from SPP.
- Generally speaking, there is a broader issue that should be addressed. And that is the lack of market systems recognizing that there are a number of generating units that have connected to the SPP system utilizing only a Generator Interconnect Agreement (GIA). The SPP Tariff has historically allowed this type of service, but the market needs to be able to recognize that these units are essentially utilizing non-firm transmission and being dispatched comparatively to units that have requested, and paid for, firm transmission service. Most NDVER's have requested and paid for upgrades to get firm transmission for delivery to their load. The Firm Transmission Rights allow a hedge however that still is not enough to offset the impacts of resources not having Firm Transmission Rights. Also getting the congestion rights needed, are at times, not possible even if having firm transmission rights. If SPP could differentiate between these types of resources and dispatch those non-firm resources that are impacting the congestion before prices become volatile that would result in a better overall market. At this time there is not much in enhancement of acquiring Firm Transmission by resources. If SPP would curtail resources without firm transmission before those with Firm it could enhance more firm transmission being requested and upgrades that the costs are currently borne by the Load.
- The SPP Market sees many periods of price spikes in the RT Market due to flowgate congestion. At what level of a price spike due to a CME event is a Reliability Signal? NPPD believes that there are times that when flowgates are "Binding" or "Breached" and flows need to change address reliability concerns it should be a Reliability Signal. The reason for the price spikes is due to a current or projected transmission line overload or N-1 condition. That is a reliability concern and that signal should be treated that way. NPPD has asked for a clarification on this subject from SPP and has yet to see a response.

Additionally, this is an example of SPP changing the market rules which were agreed upon during the SPP IM integration phase. SPP allowed the use of NDVERs and now that agreement is potentially changing with the added cost burden of the changes being placed on the member utilities.

Status: MWG reviewed

COMMENTS

Comment Author: Grant Wilkerson and Cliff Franklin on behalf of Westar

Date Comments Submitted: 2/2/2018

Westar has concerns with RR272:

Westar agrees with the NPPD comments listed at the bottom of this document but would add several considerations not addressed by SPP staff in RR272.

- First and foremost, SPP staff has repeatedly communicated their desire to make NDVER dispatchable, either through dispatch instruction NDVER clips, RR272, or in MWG discussions on wind. They state that price-following NDVERs have caused significant reliability issues since the start of Integrated Marketplace (IM) in 2014. If price-following NDVERs are the real problem, then at a minimum, SPP staff should have submitted an option for MWG consideration to penalize price-following NDVERs instead of forcing all NDVER conversions as in RR272.

- SPP provides a presentation *8.a.NDVER to DVER Conversion Analysis.pdf* claiming there have been reliability issues associated with price following NDVERs and there exists significant market efficiency benefits to be gained in forcing NDVER to DVER conversion. There is no study, nor does it include financial impacts forced upon NDVER owners/buyers in making conversions. The presentation states "78% of NDVERs have Firm PTP/Firm NITS" but fails to acknowledge that the market dispatch provides no recognition of this fact. In fact, this RR fails to recognize the fact that it is the interconnection process that has allowed additional generation to be connected to the grid creating existing generation NDVERs to become congested and now look for the NDVER party to financially remedy this short coming in market design. In SECTION 4: INDIVIDUAL NDVER RESOURCE CONVERSION – FINANCIAL ANALYSIS, SPP states, "The annual savings ranged from $94k to $115k" for a single NDVER to DVER conversion. We can assess nothing from this analysis. Was the unit the most constrained NDVER or was it truly a representation of the average. Someone once said that you can twist the arm of statistics/modeling until they confess to anything. SPP fails to provide critical information needed to make their analysis credible;

    1. What was the name and location of the NDVER resource?
    2. What was the size in MW of the NDVER resource and was it representative of all NDVERs?
    3. Is SPP claiming 5000 intervals where NDVER offers fall below LMP representative of all SPP NDVERs and is it necessary to achieve positive economics and is it representative of all NDVERs?
    4. Do NDVERs having less than 5000 intervals where their offer fell below the LMP not benefit from a NDVER conversion?
    5. What transmission constraints were applicable to the study NDVER and was it representative of all NDVERs?
    6. How many hours of negative pricing were experienced by this resource and is it representative of all NDVERs?
    7. During high wind and low load intervals, what was the bottom standard deviation LMP pricing and was it representative of all NDVERs?
    8. Did SPP re-price SCED dispatch for both the NDVER, NDVER→DVER conv, DVER, DVER+8 or did SPP staff just add subtract NDVER/DVER scenarios assuming historical LMPs would not change?
    9. What transmission constraints were applicable to the study NDVER and was it representative of all NDVERs?
    10. Would conversion of all NDVERs reduce benefits for the study NDVER if SPP completely re-priced all SPP LMP locations?
    11. Is 10/2016 – 10/207 representative of wind and wind/generation mix since market startup or did that time frame contain higher wind values that historically seen in SPP?

- RR272 effectively abrogates all NDVER PPA contracts, except for qualifying facilities, by undermining the grandfathered non-dispatchable status over older wind farms upon which their supply contracts were based. RR272 fails to address the financial exposure of owners/buyers of NDVERs by forcing them to become dispatchable which they may be incapable to perform within URD guides and which their contracts lacked notice to consider. RR272 throws NDVER owners/buyers "under the bus" by financially exposing them "economic dispatch" of which neither contract accounted for nor the unit was operationally constructed. RR272 forces NDVER conversion and abrogates NDVER contracts making RR272 unjust and unreasonable.

- RR272 fails to address the issue that many Market Participants (MPs) manage many NDVERs in the market owned by an Asset Owner which is not an MP. SPP puts the burden of NDVER conversions completely onto MPs which may not own the NDVER nor have any control over upgrades for the resource. Likewise, in cases where NDVERs capacity/energy is sold from AO seller to MP buyer, RR272 places all burden of NDVER conversion to the buyer MP in which RR272 has no regard for their inability or lack of authority to make NDVER→DVER upgrades. This will leave the buyer MP in a badly disadvantaged position to renegotiate unit upgrades and contract terms, likely resulting in significant financial loss exposure. RR272 lack of consideration for NDVER financial exposure to make them dispatchable is clearly unjust and unreasonable. RR272, at minimum, should be changed to make Generation Interconnection Owners have the burden of upgrading NDVERs.

- Last and perhaps the most import factor not considered by RR272 is SPP's market reputation. NDVERs were a condition of several MPs agreeing to transition from EIS to IM. If we go back on our word, will other MPs lose confidence in the stability of SPP tariff grandfathering and agreements made to prospective Balancing Authorities, Asset Owners, and Market Participants considering the benefits of join SPP as a stable settlement & market platform?

Status: MWG reviewed

Comment Author: Erin Cathey on behalf of the MWG

Date Comments Submitted: 2/6/2018

Description of Comments:

The MWG modified Protocol Section 6.1.8 and Attachment AE Section 2.2, incorporating language to clarify what resources can be exempt from NDVER to DVER conversion under PURPA.

Status: MWG approved and incorporated language

PROPOSED REVISION(S) TO SPP DOCUMENTS

Market Protocols

1. Glossary

Dispatchable Variable Energy Resource

~~A Variable Energy Resource that is capable of being incrementally dispatched down by the Transmission Provider.~~ As defined in Attachment AE of the tariff.

Non-Dispatchable Variable Energy Resource

~~A Variable Energy Resource that is not capable of being incrementally dispatched down by the Transmission Provider.~~As defined in Attachment AE of the tariff.

6.1.8 Dispatchable Variable Energy Resource

All Variable Energy Resources in the market must be registered as a Dispatchable Variable Energy Resource (DVER) except for ~~(i) Wind Powered Variable Energy Resources with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (ii)~~ a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility.~~, or (iii) Non-wind Variable Energy Resources registered on or prior to January 1, 2017 and with an interconnection agreement executed on or prior to January 1, 2017. VERs included in (i) and (iii) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider.~~ A Generation Interconnection Customer with Variable Energy Resources that are not QFs exercising their rights under PURPA previously registered as an NDVER must convert to a DVER on or prior to July 1, 2020. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the DVER market rules including Uninstructed Resource Deviation Charges.

Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resources.

(1) A Dispatchable Variable Energy Resource is eligible to submit Offers for Regulation-Down if that Resource qualifies to provide Regulation-Down by passing the test described under Section 6.1.11.3.

(2) A Dispatchable Variable Energy Resource is not eligible to submit Offers for Regulation-Up, Spinning Reserve or Supplemental Reserve;

(3) Dispatchable Variable Energy Resources are committed and dispatched the same as any other Resource in the Day-Ahead Market.

(4) For the RUC and RTBM, special commitment and dispatch rules apply as defined under Section 4.2.2.5.5.

(5) Dispatchable Variable Energy Resource data submittal requirements are defined in ~~the SPP Criteria~~ Section 4.1.2.

6.1.9 Non-Dispatchable Variable Energy Resource

~~Variable Energy Resources that qualify may register as a Non-Dispatchable Variable Energy Resource. The Market Participant registering a Non-Dispatchable Variable Energy Resource must provide documentation to SPP verifying that it meets one or more of the exceptions in Section 6.1.8. Otherwise, the Resource must be registered as a Dispatchable Variable Energy Resource.~~Only a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Non-Dispatchable Variable Energy Resource. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

NDVERs are committed and dispatched the same as any other Resource in the Day-Ahead Market. For the RUC and RTBM, special commitment and dispatch rules apply as defined under Section 4.2.2.5.6. Non-Dispatchable Variable Energy Resource data submittal requirements are defined in Section 4.1.2~~in the SPP Criteria~~.

Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the market that is capable of being incrementally dispatched by the Transmission Provider.

Non-Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the market that is not capable of being incrementally dispatched by the Transmission Provider.

2.2 Application and Asset Registration

…

(10) All Variable Energy Resources in the market must be registered as a Dispatchable Variable Energy Resource (DVER)~~All Variable Energy Resources must register as a Dispatchable Variable Energy Resource~~ except for ~~(1) a wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (2)~~ a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility~~ or (3) a non-wind powered Variable Energy Resource registered on or prior to January 1, 2017 and with an interconnection agreement executed on or prior to January 1, 2017~~. ~~Variable Energy Resources included in (1) and (3) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider.~~ A Generation Interconnection Customer with Variable Energy Resources that are not QFs exercising their rights under PURPA previously registered as an NDVER must convert to a DVER on or prior to July 1, 2020. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

…