CONFIDENTIAL 4 CSR 240-2.135(2)(A)3,4,6

Issue: GFSA
Witness: James McMahon
Type of Exhibit: Surrebuttal Testimony
Sponsoring Party: The Empire District Electric Company
Case No: EO-2018-0092
Date: March 13, 2018

Before the Public Service Commission of the State of Missouri

Surrebuttal Testimony

of

James McMahon

March 13, 2018

<u>Denotes Confidential**</u>**

Liberty Utilities
EMPIRE DISTRICT

PUBLIC VERSION

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OF
JAMES MCMAHON
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. EO-2018-0092

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SURREBUTTAL TESTIMONY
OF
JAMES MCMAHON
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. EO-2018-0092

I. BACKGROUND

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND TITLE.

A. My name is James McMahon. I am a Vice President at Charles River Associates ("CRA") in the energy practice.

Q. ARE YOU THE SAME JAMES MCMAHON THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I filed direct testimony on behalf of The Empire District Electric Company ("Empire" or Company"). My professional background and qualifications are contained in that prior testimony.

II. INTRODUCTION

Q. CAN YOU PLEASE SUMMARIZE THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the questions, comments, and criticisms raised by the Staff of the Commission ("Staff"), the Office of the Public Counsel ("OPC"), and Midwest Energy Consumer Group ("MECG") in their respective rebuttal testimonies regarding Empire's Generation Fleet Savings Analysis ("GFSA").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have organized my testimony as follows:

First, I describe how the results of the Company's Request For Proposal ("RFP") process to acquire up to 800 MW of wind in or near Empire's service territory compare favorably to the assumptions used in the Generation Fleet Savings Analysis ("GFSA"). I also describe how through additional modeling that we performed using these results and other updates, the expected savings for Empire customers actually increased.

Second, I summarize the key questions raised in the testimony of Staff, OPC, and MECG regarding the GFSA and provide my response to each of these.

Third, I describe the additional analysis that Empire completed at the request of parties in this docket, and how these additional analysis continue to affirm the savings demonstrated in the GFSA.

Fourth, I describe my opinion on Empire's resource planning process that served as the foundation for the GFSA and how that process compares to industry best practices.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE ISSUES RAISED BY STAFF, OPC AND MECG REGARDING THE GFSA AND WHETHER IT IS APPROPRIATE FOR THE COMMISSION TO RELY ON THE GFSA IN EVALUATING THE CUSTOMER SAVINGS PLAN ("CSP").

A. For a regulated utility focused on lowering cost and limiting risk to customers, the CSP is compelling. Retiring Asbury and replacing it with up to 800 MW of low LCOE[1] wind will generate 20-year Net Present Value ("NPV") revenue requirement savings of $325 million, compared to the current Preferred Plan, including significant near term benefits for customers. While these savings were originally based on cost estimates for a hypothetical wind farm, they are now based on bids in hand from project developers with real projects and real world experience.

I understand well the concerns raised by the parties, mostly driven by a fear of making a mistake or from a focus on past decisions to invest in a coal plant that is now less economic. I also understand that this Company told the Commission in past Integrated Resource Plan ("IRP") process and rate cases that Asbury should be retained. But circumstances have changed. We have experienced large reductions in wind costs that, combined with the Production Tax Credit ("PTC") and tax equity financing capability, make wind incredibly cost effective. Empire expects today that the wind proposed as

[1] The levelized cost of electricity, or LCOE, is an estimate of the per-unit (MWh) cost of a particular generating resource over the life of the resource. This includes any variable and fixed operating costs and capital costs associated with the resource.

part of its CSP will cost just $22-$24/MWh on a levelized cost basis. This compares to $38/MWh for Asbury, and $55/MWh [2] for a gas Combined-Cycle in the market.

Make no mistake, the CSP is a big step forward for Empire. The Company will shift from a heavily fossil portfolio with emission, fuel, and capital cost risk to a portfolio with strong environmental attributes and much lower fuel and ongoing capital costs. Under the new portfolio, a majority of the power Empire generates will be from clean, low-cost wind. Empire's current portfolio construction is well-positioned for this transition as well: Empire's large amount of flexible gas assets will help facilitate the increased energy from the wind. This will leapfrog Empire ahead of many of its peers and position the Company strategically well today and into the future with a low cost, low risk, and sustainable source of energy.

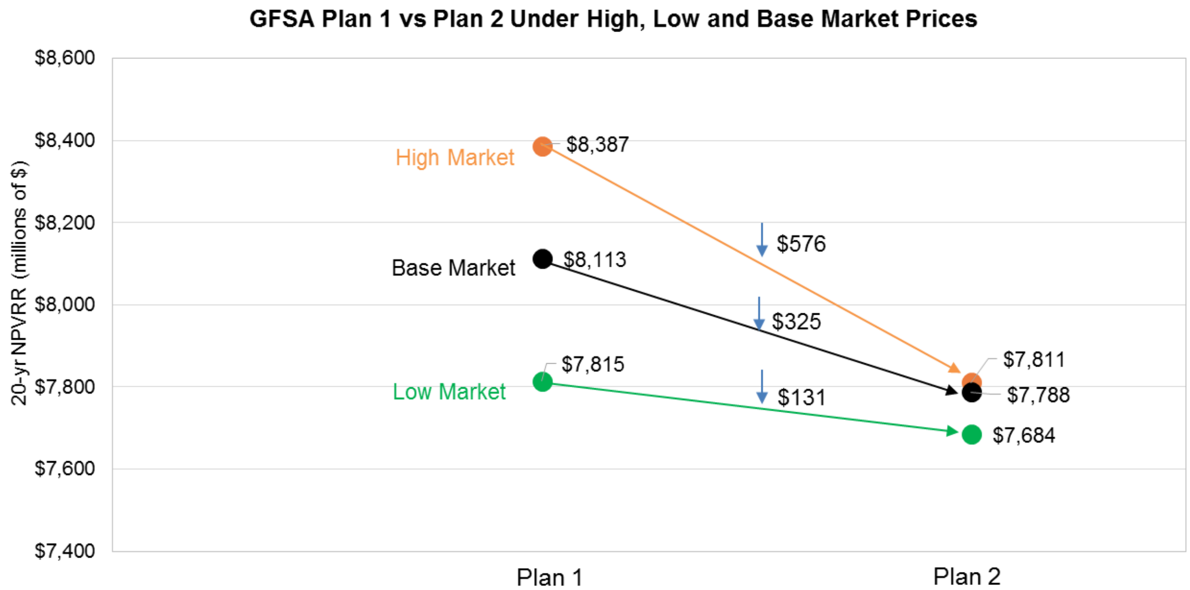
This rebalancing of the portfolio is not a knee-jerk reaction to a "one-time sale" or an attempt to buy low and sell high. Rather, it is an educated decision that reflects the fundamental change that Empire is observing in the energy markets, the federal tax credits <u>and</u> the unique opportunity this utility has to own low cost wind in the Southwest Power Pool. While Empire expects the costs of wind to continue to decline over time, the hefty tax credits that make the benefits so clear and convincing for Empire are scheduled to phase out soon. This brings the question to a head and is why Empire is seeking to make the CSP a reality.

[2] Workpaper "Attachment_Generator Fleet Savings Analysis – DH 2017 1103", "Summary" tab.

Q. WILL PURSUING THE CSP INCREASE RISK FOR EMPIRE'S CUSTOMERS?

A. No. Several parties have raised the concern that retiring Asbury and adding wind to the portfolio will increase risk to the portfolio and to Empire customers over the status quo. Yet the opposite is true, which has been proved out by the many modeling runs and analysis performed in the GFSA and at the request of parties. Wind reduces portfolio risk because, relative to conventional resources, wind's costs are more certain. The vast majority of a wind project's costs are incurred during construction and are reasonably foreseeable. Fossil plants, on the other hand, tend to have significant fuel costs that are a major expense through the plant's life. As history suggests, fossil fuel prices can shift significantly over time and can be difficult to forecast with accuracy. As Figure 1 illustrates below, the GFSA actually reduces risk for customers, narrowing the range of probable outcomes as compared with the current Preferred Plan. The high market case illustrates the benefit of a zero fuel resource in the portfolio. Plan 2 is significantly less expensive than Plan 1. On the other hand, even where market prices fall below expected levels due to flatter natural gas costs than expected, a concern raised by some, Empire customers are hedged against this risk by cost reduction in other parts of the portfolio. The risk is not in pursuing the CSP, the risk is in not pursuing the CSP.

Figure 1: GFSA Plan 1 and 2



III. PRELIMINARY RFP RESULTS CONFIRM THE WIND ACQUISITION ASSUMPTIONS IN THE GFSA

Q. MECG WITNESS MEYER INDICATED THAT HE DID NOT KNOW WHAT CONTRACTORS WOULD BE CONSTRUCTING THE 800 MW OF WIND ASSOCIATED WITH THE CSP AND SUGGESTED THAT RESPONSES TO THE RFP HAD BEEN RECEIVED BY THE TIME HE FILED REBUTTAL TESTIMONY. MR. MEYER DESCRIBED THIS INFORMATION AS CRITICAL TO THE CSP (REB., P. 4, 5). DID EMPIRE RECEIVE BIDS FROM DEVELOPERS RELATED TO AN RFP IT RECENTLY CONDUCTED FOR WIND?

A. Yes. As explained further in Empire witness Wilson's Surrebuttal Testimony, Empire conducted an RFP to solicit proposals to build up to 800 MW of wind generation in or near Empire's service territory. Through this process, Empire received bids from 10 developers, reflecting 18 sites that were owned by the developer. Six of the bidders also bid on Empire's two sites in Missouri[3].

Q. SINCE THE FILING OF THE GFSA, HAS THE COMPANY REVIEWED THE RESULTS OF THE RFP?

A. Yes. Empire witness Wilson discusses the process and preliminary results in his Surrebuttal Testimony.

Q. HOW DID THE PRELIMINARY RFP RESULTS GET INCORPORATED INTO THE GFSA MODELING?

A. Empire re-ran the GFSA analysis using preliminary RFP results in place of the hypothetical wind projects in the GFSA. Empire ran three cases, each involving unique combinations of proposed wind projects from the **________________________________ ____ ____ ____ ____ ____________**.

Q. HOW WAS EACH OF THE RFP CASES MODELED IN THE UPDATED ANALYSIS?

3 *See* Surrebuttal Testimony of Timothy N. Wilson, page 4.

A. The three RFP portfolios described above were converted into modeling inputs for purposes of running the updated analysis. The updated model inputs were developed as follows:

- Capital costs were based on the build and transfer prices from the RFP plus an estimate of internal financing and project management costs.
- Fixed O&M costs were based on the RFP results plus some additional modifications.
- Variable O&M payments to tax equity and PAYGO payments from tax equity were calculated for each project and had a unique value for each year from years 1 to 10.
- 8760 wind profile was based on the RFP responses and adjusted by the recommendation of the wind resource engineering firm DNV.
- Transmission interconnection costs were assumed to be the costs from the low-LCOE wind farm.
- Congestion, or basis differential, was the same as was used in the mid LCOE wind case from the GFSA.
- Tax equity estimates were calculated using the same methodology as the GFSA low and mid LCOE wind.

Q. WAS ANY OTHER DATA UPDATED FROM THE GFSA ANALYSIS WHEN EMPIRE RAN THE PRELIMINARY RFP RESULTS?

A. Yes. In addition to running scenarios with specific RFP locations and costs in mind, Empire revised estimates of fixed O&M and variable O&M related to power generation to more accurately represent the costs of items such as repowering capital, tax equity contributions, and the sponsor equity buyout.

Q. HOW DO THE FINANCIAL AND PERFORMANCE RELATED ASSUMPTIONS FOR THE PRELIMINARY RFP RESULTS COMPARE TO THE ASSUMPTIONS IN THE GFSA?

A. The preliminary results of the RFP are supportive of the assumptions used in the GFSA for the cost to acquire up to 800 MW of low LCOE wind[4]. As Table 1 illustrates, **__________** from the Wind RFP has an estimated LCOE of $24/MWh compared to $22/MWh for Plan 2 from the GFSA.

Table 1: Comparison of Preliminary RFP Results Versus GFSA Assumptions

	Low-LCOE Wind (GFSA)	Initial RFP Results
All-In Capital Cost ($2020)	$1806/kW	$1573/kW
EDE Capital Cost ($2020)	$726/kW	$701/kW
Capacity Factor	54%	47%
Tax Rate Change	35%	21%
Basis	Low-LCOE Basis	Mid-LCOE Basis
Transmission Interconnection	Low-LCOE Connection Costs	Low-LCOE Connection Costs
Online Date	2019	2020
LCOE ($/MWh)	**$21.52**	**$23.89**

[4] Low LCOE wind refers to the low cost wind resource option that was modeled in the GFSA.

The all-in capital cost of the Plan 2b wind is significantly below the estimated cost of low LCOE wind in the GFSA. The capacity factor of the Plan 2b wind is estimated at 47%, which is more consistent with mid LCOE wind. This is expected given the projects' proximity to Empire's service territory.

Q. DO THE RFP RESULTS REVEAL ANY OTHER BENEFITS OVER THE LOW LCOE WIND PROJECT IN THE GFSA?

A. Yes. In the GFSA, Empire assumed that low LCOE wind would be located in Kansas, in a location comparable to Elk River. Because of its location away from load and historical congestion, Empire discounted the price that the wind would receive at Elk River by 13.5%. The preliminary RFP results, however, indicated attractive projects located relatively close to Empire's service territory, more consistent with the mid LCOE wind in the GFSA. Thus, in the three cases that Empire modeled using the preliminary RFP results, Empire used the mid LCOE congestion discount of ~4%.

Q. WHAT WERE THE ESTIMATED CUSTOMER SAVINGS FOR THE THREE CASES USING THE PRELIMINARY RFP RESULTS?

A. All three plans demonstrate significant savings on a 10-year, 20-year and 30-year basis versus the 2016 IRP Preferred Plan as shown in Figure 2. Moreover, Plan 2b indicated increased savings levels over Plan 2 across the time period.

Figure 2: RFP Plan Savings Compared to Plan 1 ($Millions) [5]

Plan Name	10 Year	20 Year	30 year
Base 2B - 800 MW RFP Wind	$164	$396	$615
CSP Plan 2	**$71**	**$325**	**$607**
Difference (increased savings)	*+$93*	*+$71*	*+8*
Alternative Cases			
550 MW RFP Wind	$145	$309	$484
500 MW RFP Wind	$85	$194	$338

Q. HOW DID THE STOCHASTIC RESULTS COMPARE TO THE ORIGINAL PLAN 2 IN THE GFSA?

A. The stochastic results emphatically confirmed the findings of the GFSA. Under both 20-year and 30-year NPVRRs, the updated Plan 2B was lower cost under all 54 stochastic endpoints, with customer savings between $48 million and $682 million on a 20-year basis and between $126 million and $1,049 million on a 30-year basis.

Q. HAS THE WIND RFP SCENARIO CHANGED EMPIRE'S RECOMMENDATION IN THE GFSA OF RETIRING ASBURY AND BUILDING UP TO 800 MW OF LOW LCOE WIND?

A. No. The RFP results validate the findings of the GFSA that retiring Asbury and adding up to 800 MW of low LCOE wind will provide significant savings for Empire's customers over the 2016 IRP Preferred Plan.

[5] See Results Wind Study_Corporate Tax Change_RFP Wind Plans.xlsb for more information on the updated results (Surrebuttal Workpaper).

IV. EMPIRE'S FURTHER RESPONSE TO ISSUES RAISED IN TESTIMONY OF STAFF, OPC, AND MECG

Q. CAN YOU SUMMARIZE THE ISSUES RAISED BY STAFF, OPC, AND MECG?

A. Yes. The following issues were raised by Staff, OPC, and MECG:

- OPC witnesses Robinett, Riley, Marke and Mantle question the need to modify Empire's 2016 IRP Preferred Plan, particularly in light of past investments made in Asbury;
- OPC witness Mantle, Staff witness Rogers, and MECG witness Meyer question the loss of coal as a baseload resource in SPP and in Empire's portfolio;
- Staff witness Rogers and MECG witness Meyer express concern with the lack of upfront (first ten-year) savings in the CSP;
- OPC witnesses Marke and Mantle and MECG witness Meyer question the amount of market price uncertainty and the risk of lower than expected prices in SPP;
- OPC witness Mantle and Staff witness Rogers question the reliance on "off-system" sales to provide customer savings, and;
- Staff witness Rogers questions the benefits of retiring Asbury.

I address each of these issues in my testimony below.

a. THE NEED TO MODIFY EMPIRE'S 2016 IRP PREFERRED PLAN AND PAST INVESTMENT IN ASBURY

Q. OPC WITNESS RILEY STATES THAT "EMPIRE'S PLAN WILL PLACE UNNECESSARY COST ON EMPIRE'S CUSTOMERS SINCE EMPIRE'S CURRENT RESOURCE PLAN DOES NOT CALL FOR THE ADDITION OF ANY RESOURCES TO MEET ITS CUSTOMERS' NEEDS UNTIL 2029 AT THE EARLIEST." (REB., P. 3) IS THIS A REASONABLE POSITION?

A. No, absolutely not. Additional resources do not necessarily imply higher costs versus the status quo. Maintaining the 2016 IRP Preferred Plan is expected to cost customers $325 million on a 20 year net present value revenue requirement basis and $607 million on a 30 year net present value revenue requirement basis relative to replacing it with the GFSA Plan. Maintaining the 2016 IRP Preferred Plan also leads to greater levels of risk than the GFSA. Empire illustrated in the GFSA risk analysis that Plan 2 is less costly than Plan 1 in almost all market price scenarios. Under the stochastic analysis from the GFSA, Empire determined that 92.5% of the time, the GFSA will generate material savings for Empire's customers, ranging between $131 million to $850 million over 20 years. Moreover, the GFSA actually *reduces* exposure to market price risk for Empire's customers.

Q. IS THE FACT THAT THE 2016 IRP PREFERRED PLAN DOES NOT CALL FOR NEW GENERATION UNTIL 2029 A REASONABLE BASIS FOR NOT CONSIDERING ALTERNATIVE PLANS THAT RETIRE AND BUILD NEW CAPACITY SOONER?

A. No, of course not. The very purpose of the resource planning exercise is to consider the most effective portfolio for supplying power to customers, minimizing costs, limiting risks, and meeting any other objectives the company has identified. Retirement and replacement is an essential option that every utility should have available to enable it to pivot when market, operating conditions, or government policy changes. That certainly is the case here, where market conditions have changed recently, the cost of wind resources have declined dramatically, coal compliance policy has changed, and federal production tax credits are expiring.

Q. IN YOUR OPINION, HAVE MARKET CONDITIONS CHANGED SUFFICIENTLY TO CONSIDER RETIREMENT AND NEW GENERATION OPTIONS?

A. Yes, as discussed in my Direct Testimony there are a number of conditions that have changed in the last several years that warrant a new look at Empire's generation portfolio. Expected wind capacity factors in both SPP and Empire's service territory have dramatically increased due to technological improvements. Likewise, capital costs for wind have decreased drastically over the last five years, placing wind generation on an almost equal footing with many fossil-fuel technologies from a purely cost to procure perspective. Finally, persistently low gas and power prices over the last few years have negatively impacted the economics of traditional baseload resources like coal and nuclear plants in favor of low-cost resources like natural gas and renewables.

Q. OPC WITNESS MARKE STATES THAT EMPIRE'S DECISION TO INVEST IN ENVIRONMENTAL RETROFITS WOULD NOT HAVE BEEN PRUDENT IF ASBURY WAS GOING TO BE IN SERVICE FOR ONLY ANOTHER FIVE

YEARS. (REB., P. 9) HOW ARE PAST DECISIONS TO SPEND ENVIRONMENTAL CAPITAL ON ASBURY RELEVANT TO THE GFSA?

A. It is not relevant, and it is important to point out that the decision to make the environmental upgrade at Asbury was not made in 2014, but rather has a history that dates back to the mid-2000s, as Mr. Mertens explains in his Direct Testimony (p. 13-14) and Surrebuttal Testimony (p. 11). That decision was based on the best available information at the time regarding the future fuel and electricity prices, technology costs, load, and a number of other assumptions. To the extent market and operating conditions have changed for Asbury such that the plant is more cost effective to retire, action should be taken. I can appreciate the difficulty in accepting that Asbury is no longer a cost effective element of the Empire generation portfolio.

b. <u>COAL AS A BASELOAD RESOURCE</u>

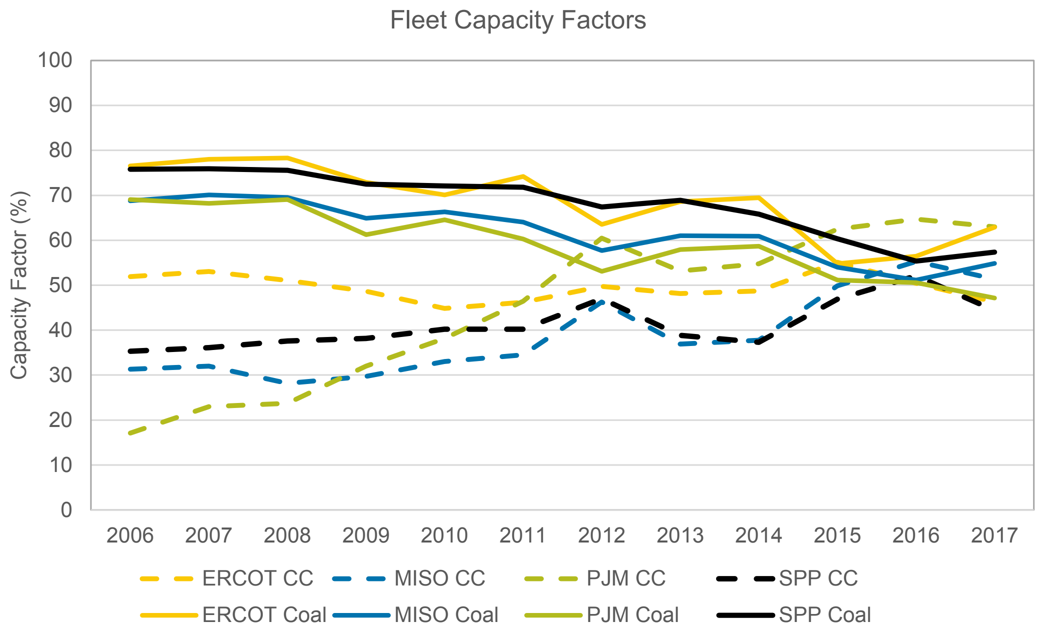
Q. ON PAGE 15 OF HER REBUTTAL TESTIMONY, OPC WITNESS MANTLE DESCRIBES DIFFERENT RESOURCE OPTIONS. CAN YOU SUMMARIZE HER VIEWS?

A. Yes. Ms. Mantle describes four types of capacity resources: baseload, intermediate, peaking, and intermittent. For baseload resources, she describes plants that run in all hours and follow load because they have the lowest variable costs. She provides coal as an example of a baseload resource. For intermediate resources, she describes plants that run less frequently than baseload due to their dispatch costs being generally higher. She provides combined cycle gas plants as an example of intermediate resources. For peaking plants, she describes plants that run for short periods of time and generally have a higher cost to run. She provides natural gas and oil CTs as examples of peaking resources.

Q. DO YOU AGREE WITH MS. MANTLE'S CHARACTERIZATION OF COAL RESOURCES AS BASELOAD?

A. No. I find her characterization inconsistent with the current planning environment. Today, much coal in the U.S. is not a baseload resource. Figure 3: shows the average capacity factor for U.S. coal and natural gas combined cycle plants in four different regions over the last 10 years. Coal capacity factors have generally trended downward (from around 75% to around 55% on average in SPP), and gas combined cycle factors have generally trended upward (from around 35% to nearly 50% in SPP). In addition, more than 43 gigawatts of coal-fired capacity has been retired in the past five years. In many places in the United States, including Empire's service territory, coal is less competitive today than efficient gas-fired generation. Thus, plants like Asbury do not run in all hours as Ms. Mantle suggests. In 2017, Asbury's capacity factor was 57%.

Figure 3: Average CC and Coal Capacity Factors by RTO



Q. DO YOU AGREE WITH MS. MANTLE'S CHARACTERIZATION OF GAS COMBINED CYCLE RESOURCES AS INTERMEDIATE?

A. No, not necessarily. In some cases, combined cycle resources serve the role that Ms. Mantle describes, but in other cases they do not. Today, many gas combined cycle plants have dispatch costs near or below many coal plants. Thus, depending on the proximity to load and other plants, a combined cycle plant today can run some of the time or nearly all of the time.

Q. WHY IS IT IMPORTANT TO POINT OUT HOW YOU DIFFER WITH MS. MANTLE IN DEFINING BASELOAD AND INTERMEDIATE GENERATION?

A. Because Ms. Mantle suggests that Empire's fleet today is optimized because it comprises a mix of baseload, intermediate, and peaking resources.

Q. DO YOU AGREE THAT A UTILITY PORTFOLIO SHOULD INCORPORATE A MIX OF BASELOAD, INTERMEDIATE, AND PEAKING GENERATION?

A. While the concept of mixing baseload, intermediate, and peaking resources is relevant to portfolio optimization, the reality is that resource planning today is much more complex. An intermittent resource, like wind, has much more value as an energy resource than a capacity resource, but can be paired with low cost capacity resources or storage to meet a utility's capacity requirements. Thus, a utility today needs to consider how capacity resources fit with energy resources to meet reserve margin requirements and minimize costs to customers, among other objectives.

Q. HAVE YOU SEEN OTHER UTILITIES RETHINKING HOW CAPACITY AND ENERGY RESOURCE FIT TOGETHER?

A. Yes. MidAmerican, an Iowa based utility, is expected to generate more than 90% of its customers' annual energy consumption by the end of 2020 from renewables, primarily from wind power.[6] Xcel Energy is also investing heavily in wind over the next five years, planning to add over 3,000 MW of new wind projects across its regulated utilities in six states. Xcel is projecting that by 2027, 47% of its generation will come from renewables.[7] These utilities are building large amounts of wind, not for the capacity value, but for the significant levels of low-cost energy that the projects are expected to produce.

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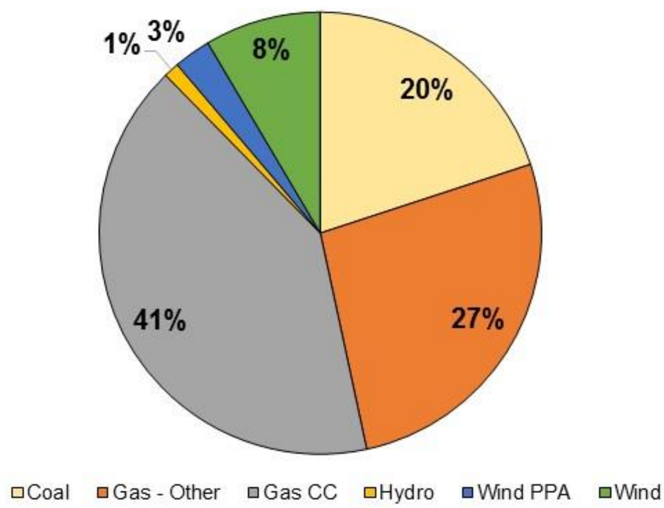
[6] https://www.midamericanenergy.com/wind-energy.aspx
[7] http://investors.xcelenergy.com/Cache/1500105918.PDF?O=PDF&T=&Y=&D=&FID=1500105918&iid=4025308]

Q. OPC WITNESS MANTLE ILLUSTRATES THAT UNDER THE GFSA WIND WILL COMPRISE 46% OF EMPIRE'S CAPACITY. (REB., P. 17) IS THIS ACCURATE?

A. The wind resource will be capable of generating an amount of power that is 46% of all of Empire's capacity, when running at full output. However, for purposes of reliability, SPP counts only 15%[8] of that wind toward meeting Empire's capacity requirements. Thus a more appropriate characterization of Empire's capacity is in the figure below, with wind only making up approximately 11-12% of Empire's total accredited capacity.

Figure 4: Empire Capacity by Fuel Type



Q. MS. MANTLE ALSO ARGUES THAT UNDER THE GFSA, WIND WILL COMPRISE 51% OF EMPIRE'S GENERATION OUTPUT. IS THIS ACCURATE?

[8] The 15% is an estimate based on SPP's historical treatment of Empire's Elk River and Meridian Way wind farms. Actual accredited capacity will be calculated for each wind project.

A. Yes, under the GFSA wind will comprise 51% of all megawatt-hours produced by Empire resources after it enters into service. Over time, this number is projected to decrease as a result of load growth and other changes to the Empire portfolio, such that the share is less than 40% by 2031.

Q. WHY DO YOU BELIEVE A PORTFOLIO THAT GENERATES APPROXIMATELY HALF OF ITS POWER IN THE FORM OF WIND IS NOT A PROBLEM FOR EMPIRE?

A. There are several reasons that a portfolio that generates half its power in the form of wind is not a problem for Empire:

- First, the GFSA represents a plan optimized around meeting reserve requirements and minimizing costs to Empire customers. Because of tax incentives, declining capital costs, and improving performance, wind has become an exceptionally low cost energy resource.
- Second, wind reduces portfolio risk because, relative to other resources, wind's costs are more certain. The vast majority of a wind project's costs are incurred during construction and are reasonably foreseeable. Fossil plants, on the other hand, often have significant fuel costs which are a major expense throughout the plant's life. As history suggests, fossil fuel prices can shift significantly over time.
- Third, Empire's shift toward having more wind in the portfolio is consistent with the industry trend and the actions other utilities in SPP, such as Xcel and MidAmerican.

- Finally, as Company witness Mertens also discusses in Surrebuttal Testimony, the addition of wind to the Empire generation mix causes no concerns from an operations or reliability perspective. Again, Empire's large fleet of flexible gas assets will help facilitate the wind energy production.

c. UPFRONT SAVINGS FROM THE CSP

Q. MULTIPLE PARTIES HAVE EXPRESSED CONCERN THAT THE CUSTOMER SAVINGS PLAN SAVINGS ARE "BACK-LOADED" AND PROVIDE LIMITED SAVINGS IN THE NEAR TERM. WHAT EXACTLY IS THE NATURE OF THAT CONCERN?

A. Although the GFSA indicates significant expected customer savings over both 20-year ($325 million) and 30-year periods ($607 million), the savings in the first ten years were lower ($71 million).

Q. HAS EMPIRE MADE ANY CHANGES IN ITS REVISED ANALYSIS THAT WOULD IMPACT THE EARLY YEAR SAVINGS?

A. Yes. In addition to running scenarios with specific RFP locations and costs in mind, Empire revised its estimates of fixed O&M and variable O&M related to power generation to more accurately represent the costs of items such as repowering capital, tax equity contributions, and the sponsor equity buyout. These updated estimates, combined with the specific updated RFP inputs, produced significantly increased upfront savings in the first ten years of the forecast. Plan 2B, described earlier, results in customer savings of $164 million over the first ten years of the forecast, compared to $71 million for Plan 2. Figure 5 compares NPVRR customer savings for Plan 2, 2B, and the two alternative RFP results cases over the first ten years.

Figure 5: 10 Year Savings GFSA versus RFP

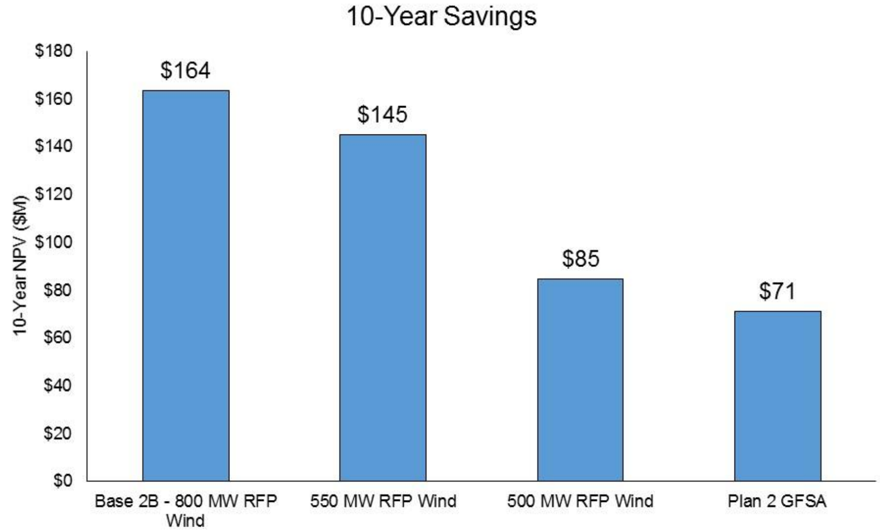
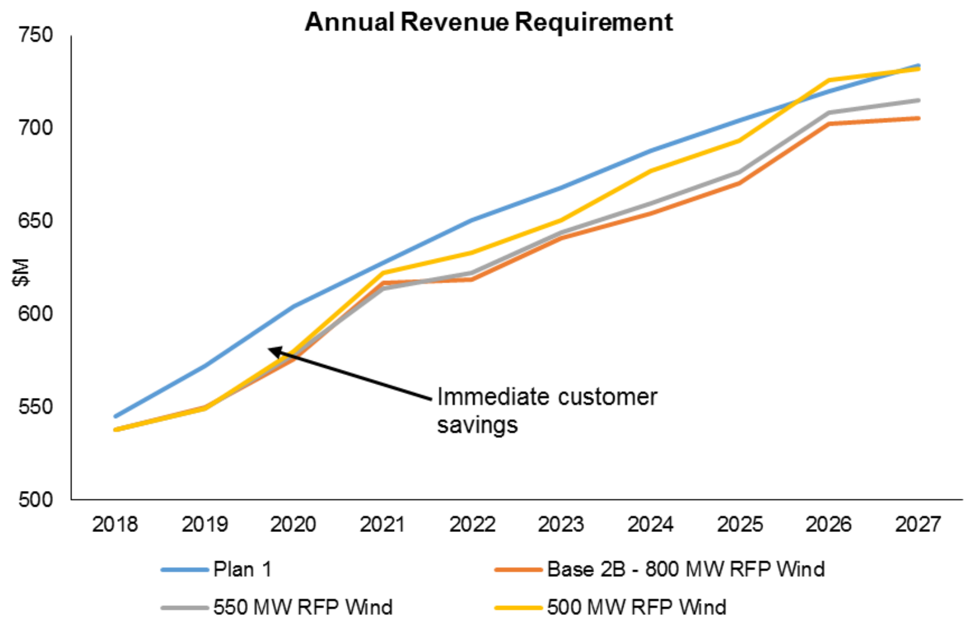


Figure 6 illustrates the annual revenue requirement of Plan 1 versus Plan 2B and the two alternative RFP cases.

Figure 6: Annual Revenue Requirement: Plan 1 vs. RFP Results Plans



d. MARKET PRICE UNCERTAINTY

Q. PLEASE SUMMARIZE THE CONCERNS RAISED BY OPC AND STAFF REGARDING THE MARKET RISK ASSOCIATED WITH THE WIND PROPOSED IN THE GFSA.

A. OPC witnesses Marke and Mantle and Staff witness Rogers raise concerns that the market revenue Empire expects to receive from operating up to 800 MW of new wind could be overstated due to the market price expectation. Their concerns fall into primarily three areas:

(1) Dr. Marke, Ms. Mantle, and Mr. Rogers argue that wind is being added to the system more quickly than Empire's modeling suggests which could drive market prices lower than expected (Marke Reb., p. 22; Mantle Reb., p. 11; and, Rogers Reb., p. 10);

(2) Ms. Mantle argues that a downward trend in electric prices and occasional negative pricing in SPP today suggest that Empire's upward sloping market price forecast is unreasonable (Mantle Reb., p. 8), and;

(3) Ms. Mantle and Mr. Rogers argue that the addition of Mountain West Transmission Group ("MWTG") to SPP, as currently contemplated, could lower market prices (Mantle Reb., p. 14; and, Rogers Reb., p. 10).

i. WIND ADDITIONS AND COAL RETIREMENTS IN SPP

Q. PLEASE DESCRIBE WHY DR. MARKE BELIEVES THAT MORE WIND IS BEING ADDED TO SPP THAN EMPIRE MODELED.

A. Dr. Marke believes that Empire may have underestimated the amount of wind being added to SPP in the GFSA modeling. Dr. Marke provides several examples of projects that were not included in Empire's modeling, but may come online. First, he describes Kansas City Power & Light's recently announced PPA with Pratt Wind and Prairie Queen for 444 MW. Second, he describes the 2,000 MW Wind Catcher project and the Dakota Community Wind project which were weighted 50% and 10% respectively in Empire's modeling. Finally, he points out that Empire's own planned project was not included in the modeling. Despite these differences Dr. Marke indicates that he does not necessarily disagree with Empire's analysis. Rather, he uses the differences to point out the potential margin for error in the range of wind addition assumptions.

Q. DO YOU AGREE WITH DR. MARKE REGARDING THE POTENTIAL MARGIN OF ERROR IN FORECASTING WIND ADDITIONS IN SPP?

A. Yes, I agree that it can be difficult to forecast specific projects. Wind projects require various permits and approvals to be constructed and can be delayed unexpectedly. Indeed, the Dakota Community Wind project that Dr. Marke cites now appears to be in doubt[9], and the Wind Catcher project has recently received an unfavorable decision from an Oklahoma administrative law judge.[10] I also note that to be eligible for the full PTC, projects must be in service by the end of 2020 and have qualified as having commenced construction by the end of 2016.

[9] https://www.argusleader.com/story/news/2017/11/30/developers-ditch-wind-power-easements-lincoln-county/910333001/
[10] https://www.bloomberg.com/news/articles/2018-02-12/biggest-ever-u-s-wind-farm-suffers-blow-from-oklahoma-judge

Q. BEYOND THE GFSA, DID EMPIRE SEPARATELY MODEL A CASE FOR OPC WHERE MORE WIND WAS ADDED TO THE SYSTEM?

A. Yes. OPC requested a modeling case that reflected a more current set of assumptions regarding wind additions and coal retirements in SPP.

Q. CAN YOU DESCRIBE THE ASSUMPTIONS FOR WIND ADDITIONS THAT WERE INCLUDED IN THIS CASE?

A. The case run for OPC included a view on wind additions that reflected the latest ABB reference case from the Fall of 2017 plus a probability weighting of the SPP wind queue to reflect the likelihood that some of the projects would be built. This probability weighted resulted in an additional 3.8 GW of wind added to the forecast from 2018 to 2020, for a total increase of 8.2 GW. For context, this would represent an approximate 50% increase in the total wind capacity in SPP.

Q. CAN YOU DESCRIBE THE ASSUMPTIONS FOR COAL RETIREMENTS THAT WERE INCLUDED IN THIS CASE?

A. The coal retirements were based on updated estimates from ABB to reflect what was known and expected as of September 15, 2017, when ABB's updated forecast was developed.

Q. WHAT WERE THE RESULTS OF THIS REVISED CASE ON MARKET PRICES?

A. The additional wind additions and retirements led to an average market price reduction in SPP of 5-7%. Compared to the Base Case, Plan 2 PVRR savings fell $44 million, from $325 million to $281 million.

Q. STAFF WITNESS ROGERS STATES ON PAGE 11 OF HIS REBUTTAL TESTIMONY THAT SAVINGS UNDER THIS CASE FALLS TO $160 MILLION FOR PLAN 2. IS THIS CORRECT?

A. No. In reviewing Witness Rogers' workpaper that was submitted with his testimony, I discovered that the PVRR comparison that he used in his testimony was actually comparing the NPV of Plan 2 vs Plan 1 from *2015 to 2034* instead of 2018 to 2037. The savings from 2015 to 2034 are only $160 million, but the savings from 2018 to 2037 are $121 million greater.

Q. BEYOND RUNNING THIS CASE FOR OPC, HOW WAS THE RISK OF MORE WIND ADDITIONS THAN EXPECTED CONSIDERED IN EMPIRE'S GFSA ANALYSIS?

A. The risk was considered through the modeling of low market prices in the stochastic analysis of the GFSA. The purpose of the stochastic analysis in the GFSA was to address uncertainty and ensure that a chosen plan is robust to alternative market conditions, like those contemplated by Staff and OPC. The stochastic analysis involved analyzing uncertainty across 3 major variables: market prices, transmission congestion, and carbon pricing. Empire considered three possible outcomes for market prices: high, base and low prices. In the low market case, market prices were an average of 24% lower than the base case. Note, this compares to the 5-7% decrease modeled for OPC.

Q. DID PLAN 2 GENERATE CUSTOMER SAVINGS RELATIVE TO PLAN 1 UNDER THE LOW MARKET CASE?

A. Yes. Under the low market case, Plan 2 generated $131 in customer savings relative to Plan 1. Table 2 compares the 20 year PVRR customer savings of the Base, Low Market, and OPC cases.

Table 2: Plan 2 Savings in Low Market Conditions

Scenario	Market Price Change	Savings
Base	-	$325 million
Low Market	-20% to -30%	$131 million
OPC Case: High Wind Low Coal	-5% to -7%	$281 million

Q. HAS THE ANALYSIS OF MORE COAL RETIREMENTS AND WIND ADDITIONS IN SPP CHANGED YOUR CONCLUSION THAT RETIRING ASBURY AND BUILDING UP TO 800 MW OF LOW LCOE WIND?

A. No. The results of the GFSA continue to hold even in the face of increased wind additions and coal retirements within SPP. While the amount of wind added to SPP could be somewhat higher than what Empire estimated in its GFSA, this does not alter my conclusion. First, Empire included a low market price scenario in its GFSA. *Even with market prices 20-25% lower, the GFSA is expected to generate $131 million in customer savings compared to the 2016 IRP Preferred Plan*. Second, at the request of

OPC, Empire ran a stand-alone scenario that increased wind additions and coal retirements over the GFSA levels. That case resulted in market prices falling 5-7% but produced a customer savings of $281 million.

Q. DR. MARKE ALSO RAISES A CONCERN ABOUT THE IMPACT ON PEAK AND OFF PEAK PRICING OF MORE WIND ENTRY AND COAL RETIREMENTS. CAN YOU EXPLAIN HIS CONCERN?

A. Yes. Dr. Marke posits that a sharp uptick in coal retirements and a deluge of new wind will have the effect of causing off-peak energy prices to drop due to an abundance of wind and on-peak energy prices to spike due to less coal.

Q. DO YOU AGREE WITH DR. MARKE'S CONCERN?

A. No, not necessarily. First, wind in SPP has a high capacity factor and produces during both on-peak and off-peak periods. Second, SPP currently has a very high reserve margin, so peak period energy shortages are not expected in the current analysis. Third, lower priced natural gas resources keep peak price impacts mitigated. This is reflected in the additional scenario Empire ran, where market prices in both peak and off-peak periods decreased, and overall around the clock prices fell 5-7%.

ii. <u>MARKET PRICE TRENDS</u>

Q. PLEASE SUMMARIZE OPC WITNESS MANTLE'S CRITICISM OF EMPIRE'S MARKET PRICE FORECAST.

A. Ms. Mantle points to the last three years of SPP data showing declining average market prices and increasing instances of negative market prices to contradict Empire's fundamentally produced forecast of gently rising market prices over the next 30 years. (Mantle Reb., p. 8) Ironically, Ms. Mantle also criticizes Empire for relying on the last three years of data to estimate potential nodal discounts for congested zones.

Q. DOES EVERY INTEGRATED RESOURCE PLAN USE SOME TYPE OF FORECAST?

A. Yes.

Q. DOES MS. MANTLE PRODUCE ANY MODELING TO SUGGEST THAT EMPIRE'S LONG-TERM FORECAST IS WRONG?

A. No.

Q. ARE THESE SIMILAR, IF NOT IDENTICAL, TYPES OF FORECASTS THAT EMPIRE HISTORICALLY USED IN ALL OF ITS RESOURCE PLAN MODELING?

A. Yes.

Q. DO OTHER UTILITIES USE THE SAME OR A SIMILAR FORECASTING PROCESS?

A. Yes. Ameren has used power price forecasts from ABB/Ventyx in the past, including in its most recent IRP.[11]

Q. DOES MS. MANTLE PRODUCE AN ALTERNATIVE FORECAST USING AN ALTERNATIVE APPROACH?

A. No.

Q. DOES MS. MANTLE SUGGEST AN ALTERNATIVE APPROACH TO FORECASTING MARKET PRICES?

A. No.

Q. WHY DOES MS. MANTLE NOT SUGGEST AN ALTERNATIVE APPROACH?

A. Ms. Mantle states in her testimony, "[t]here are so many uncertainties regarding market prices that are impossible to predict[12]," and "any estimate of market prices more than two years out is purely a guess due to the limited amount of historical information to base such a forecast on.[13]" It appears that Ms. Mantle does not believe there is a means today in SPP to produce a reasonable forecast of market prices.

Q. DO YOU AGREE WITH MS. MANTLE THAT UNCERTAINTY AND LIMITED HISTORICAL INFORMATION MAKE IT IMPOSSIBLE TO PRODUCE REASONABLE PRICE FORECASTS IN SPP?

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[11] MoPSC File No. EO-2018-0038, Ameren 2017 IRP Vol. 2 page 22.
[12] Mantle Reb., p. 14
[13] Mantle Reb., p. 10

A. No. Uncertainty is part of any market price forecasting exercise and is the very reason that Empire has gone to extensive effort to run alternative scenarios and a stochastic model to express outcomes in both expected case, high-low, and probability based format. Even if we were to accept Ms. Mantle's premise of "so many uncertainties," Empire should not hide its head in the sand hoping that the future will someday become crystal clear. Customer cost saving decisions absolutely can be made in the absence of certainty. Moreover, while Ms. Mantle appears to imply that recent market price observations in SPP defy explanation or prediction, they are squarely aligned with the same fundamental drivers of supply and demand that are used in Empire's forecast. That is, natural gas prices, which are a key driver of market prices, have been in period of decline the last five years due to continued shale growth and productivity gains. ABB's modeling suggests a future tightening of supply and demand leading to rising natural gas and, in turn, electricity prices over time.

Q. DO YOU HAVE CONFIDENCE IN THE APPROACH USED BY ABB TO FORECAST NATURAL GAS PRICES?

A. Yes. ABB's natural gas forecasting module uses industry standard tools and analysis to forecast both short-term and long-term natural gas prices. ABB uses a blend of liquid futures market data and cost-minimization linear programming of gas supply and demand to create fundamental forecasts of gas prices at major hubs throughout the United States.

Q. DO YOU HAVE CONFIDENCE IN THE APPROACH USED BY ABB TO FORECAST ELECTRICITY PRICES?

A. Yes. ABB's electricity price forecasting module uses industry standard tools and analysis to forecast long-term power prices. ABB uses long-term views of power supply and demand, including resource mix and buildouts, technology costs, fuel prices, load, and transmission constraints, to create prices. These prices are based on the fundamental interaction between the demand for electricity and the marginal cost to supply that electricity, using a chronological dispatch algorithm that dispatches the least cost resource given a set of constraints. As noted above, Empire, through ABB, has been producing similar forecasts for use in its IRP proceedings since before the SPP integrated marketplace was in place, and such an approach is far more rigorous than relying on observed trends over a short-term time period as Ms. Mantle does.

Q. MS. MANTLE AND DR. MARKE POINT TO AN INCREASING FREQUENCY OF NEGATIVE PRICING INTERVALS IN SPP. (MANTLE REB., P. 8; MARKE REB., P. 20, AND MEYER REB., P. 16) DO YOU AGREE?

A. Yes, observations of negative prices in SPP have increased. However, it is important to recognize that this phenomenon is highly dependent on which market in SPP is being examined and which node or sub-region within SPP is being studied.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY WHICH MARKET IN SPP IS BEING EXAMINED.

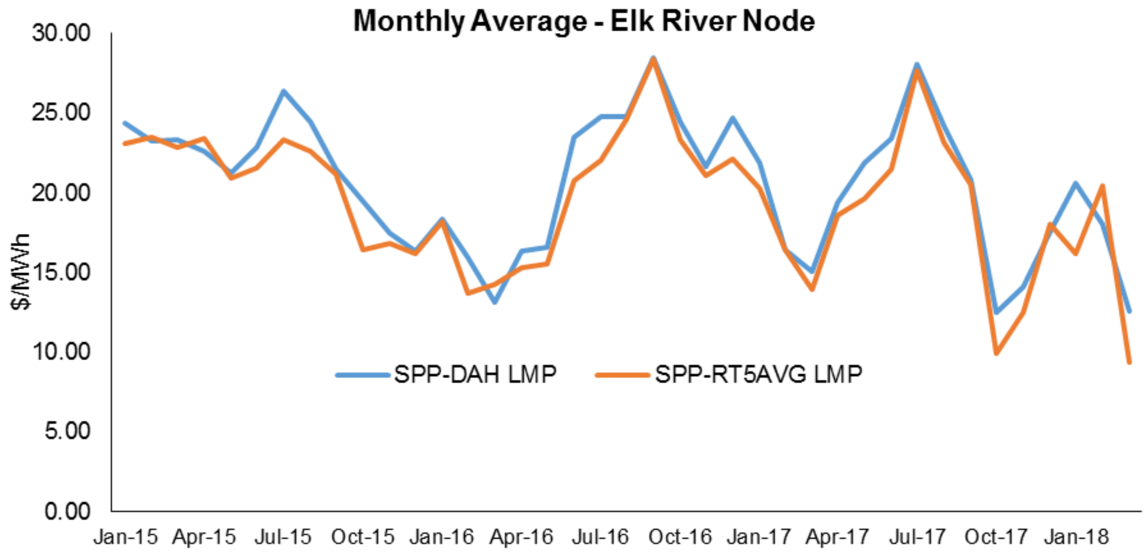
A. Two-settlement power markets like SPP have both day-ahead and real time markets, and the pricing behavior in these two markets can be significantly different. The day-ahead market financially binds resources to provide a certain amount of energy the next day at a settled price. Most market participants, including Empire, will attempt to optimize their participation of wind resources in the day-ahead market based on wind forecast predictions for the next day. During real time, however, market conditions can differ from the day-ahead forecast as a result of load changes, plant outages, and weather conditions that impact wind output. Because of this, real time prices are generally more volatile. In fact, negative prices have been much more frequent in the real time market than in the day-ahead settlement, as shown in Table 3 for the Elk River price location (the low-LCOE pricing node from the GFSA) below.

Table 3: Day-Ahead vs. Real Time Prices – Observations

Table of Observations		
Elk River Price Node (1/1/2015-3/8/2018)		
# of Observations	**Day Ahead**	**Real Time**
Less than -$30	14	310
Less than $0	888	1,705
Greater than $0	27,022	26,205
Greater than $50	351	920

Moreover, the average price in the real time market is generally lower than the day-ahead, as shown for Elk River in Figure 7 below.

Figure 7: Monthly Average Elk River Prices



It is not clear to me whether Ms. Mantle or Dr. Marke are referring to the day-ahead or real time markets in SPP or whether they have accounted for the expected participation of the proposed wind project in each market. Overall, while negative pricing has been witnessed in both markets, it has been more prevalent in the real time market, mitigating the impacts to a resource that is likely to sell most of its energy in the day-ahead.

Q. YOU ALSO MENTIONED THAT LOCATION CAN IMPACT THE FREQUENCY OF NEGATIVE PRICES. PLEASE EXPLAIN THIS FURTHER.

A. Negative pricing is more likely to occur in regions with high levels of transmission congestion, where there is more wind generation than load. This is why negative prices have been more frequent around the Elk River node than in areas closer to Empire's load. As discussed earlier, the RFP responses resulted in a short-list of wind projects that are all close to Empire's load, reducing the risk of negative pricing. This leads me to conclude that the risk of negative prices impacting the economic performance of these wind projects is much lower than if the projects were to be located in Kansas, the site of the initial low-LCOE wind from the GFSA.

Q. OPC WITNESS MANTLE STATES THAT "EMPIRE'S FORECASTED PRICES DO NOT MIMIC THE CURRENT MARKET TREND OF MORE HOURS WITH NEGATIVE PRICING." (MANTLE REB., P. 10) DO YOU AGREE?

A. No. Empire's price forecast uses location-specific historical data from the day-ahead market and develops an hourly discount that encompasses all of the observed historical data. Since it uses an averaging approach, the hours will not capture extremes in either direction, but they will effectively account for all of the prices present in the broad range of historical data without dismissing or disregarding any negative pricing. In addition, Empire also assessed a high basis risk scenario in the stochastic analysis. In that case, the average price discount was twice the historical average, effectively developing a proxy for a higher frequency of negative prices. This discount was applied for the full analysis period (20 or 30 years), which is conservative, given the potential mitigating effects of long-term transmission development to alleviate persistent nodal pricing issues.

Q. DOES EMPIRE HAVE OTHER ABILITIES TO MITIGATE NEGATIVE PRICING RISK?

A. Yes. SPP runs a Transmission Congestion Rights ("TCR") market, which offers financial rights along a transmission pathway, which can be used to hedge against congestion risk.[14] This allows market participants to mitigate all congestion price risk in exchange for a fixed fee, which is the price of the TCR. Thus, Empire intends to obtain a TCR for the new wind assets, consistent with its past practices for new assets. This TCR would be used to hedge against congestion-driven negative pricing at the location of the wind projects and protect against the extreme downsides of negative pricing risk.

iii. MOUNTAIN WEST INTEGRATION WITH SPP

Q. PLEASE SUMMARIZE OPC WITNESS MANTLE'S CONCERNS REGARDING THE POTENTIAL ENTRY OF THE MOUNTAIN WEST TRANSMISSION GROUP INTO SPP.

A. Ms. Mantle believes that it is likely that MWTG will join SPP resulting in additional wind resources in SPP.[15] Ms. Mantle appears to imply that MWTG entry will further soften SPP market prices, negatively impacting market prices.

Q. DO YOU BELIEVE IF MOUNTAIN WEST TRANSMISSION GROUP JOINS SPP IT IS A RISK TO THE GFSA PLAN?

A. No. This is a "red herring." As discussed in Empire's response to OPC data request 8012 in January, The Glarus Group (TGG) performed an independent analysis to assess

[14] https://www.spp.org/engineering/tcr-markets/

[15] Mantle Reb., p. 14

the impacts of the MWTG joining SPP Integrated Market.[16] TGG's report identified 720 MW of transmission capability between the MWTG region and SPP, and it evaluated the impacts to the market of allowing power to flow on these transmission links economically. Under the base case scenario, TGG found that economic access to the transmission lines would increase flows in both directions, with most energy going into SPP. Despite increased trading volumes, no material change was found in overall production costs for the aggregate SPP generation fleet required to serve load (a $0.01/MWh decline in SPP production costs and total system costs). Although production costs do not represent marginal prices, the minimal change in system costs is indicative of an expected small change in system prices across the SPP footprint with the integration of the MWTG. This is expected, given that the integration would only open up import capacity of 720 MW, which is not expected to be utilized fully all the time, on an average system demand in SPP that is currently around 30,000 MW.

e. SALES IN EXCESS OF EMPIRE LOAD

Q. STAFF WITNESS ROGERS DESCRIBES THE GFSA AS PROPOSING HIGH LEVELS OF OFF-SYSTEM SALES TO OFFSET THE CAPITAL COSTS OF NEW WIND. (ROGERS REB., P. 12-15) DO YOU AGREE?

A. I think it is important to distinguish Empire's operating environment today from the past. Before Empire joined SPP, Empire controlled the dispatch of its own plants. To the extent the Company was long or short energy or capacity in an hour, or believed it could

[16] "Mountain West Transmission Group – Southwest Power Pool DC Intertie Value Study" by The Glarus Group (TGG) (https://www.wapa.gov/About/keytopics/Documents/mountain-west-spp-dc-intertie-value-study.pdf)

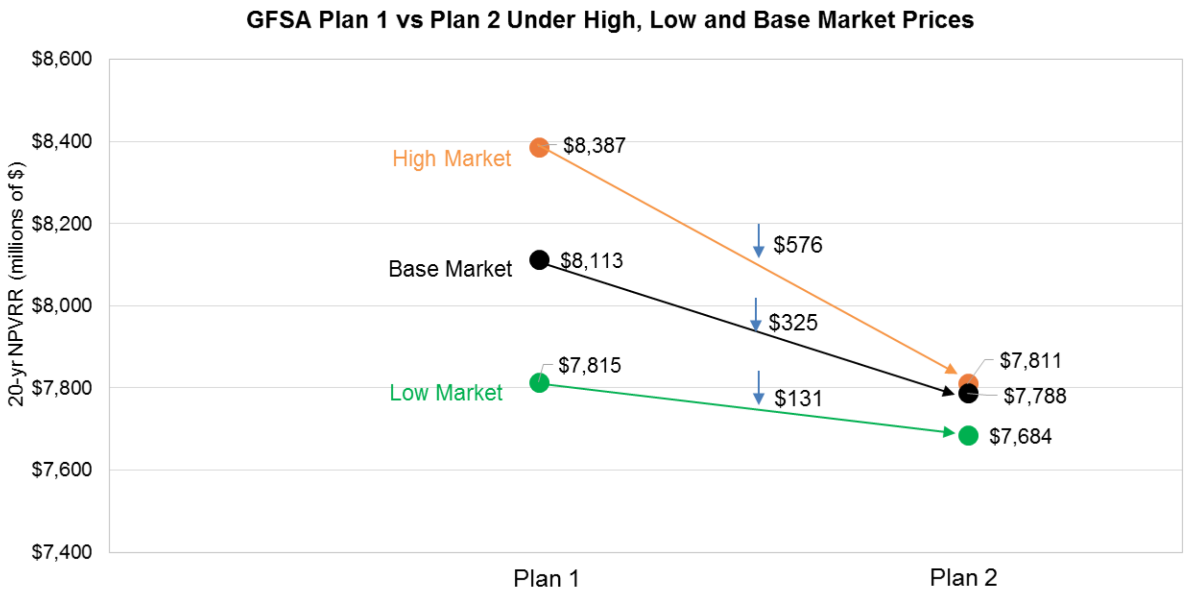
procure capacity or energy more cheaply elsewhere, it could bilaterally transact (purchases or sales) with other utilities or generation owners. Today, Empire's generation is centrally controlled and dispatched by SPP, alongside the generation of other members. SPP manages the flow of power within, through, into, and out of its system, seeking to minimize costs of electricity to its members. Empire's load buys power from SPP at a nodally-weighted market price and receives revenue for the power it generates based on the price of power at the respective generation node. As such, Empire does not have off-system sales in the traditional sense of the term.

Mr. Rogers calculates off-system sales as the difference between Empire's generation dispatch and Empire's load. Using Mr. Rogers' definition of off-system sales, I agree that the GFSA would increase off-system sales. I also agree that the incremental revenue that the new wind generates in the SPP market will more than offset its capital costs.

Q. MR. ROGERS ARGUES THAT THE INCREASE IN OFF-SYSTEM SALES MAKES THE GFSA RISKY. (ROGERS REB., P. 15) DO YOU AGREE?

A. No. I expect the CSP to reduce financial risk relative to the 2016 IRP Preferred Plan. The figure below illustrates the change in PVRR for Plan 1 (2016 IRP Preferred Plan) and Plan 2 under high, base, and low market conditions. Not only does Plan 2 reduce the base case PVRR by $325 million, it lowers the risk, as represented by the smaller spread between the cases. Moreover, Empire's analysis indicated that Plan 2 is expected to generate customer savings in all but 7.5% of the cases. Finally, even in a low market price environment, the PVRR for Plan 2 actually falls ($7,788 to $7,684). This is a result of lower production costs for Empire's other generating assets.

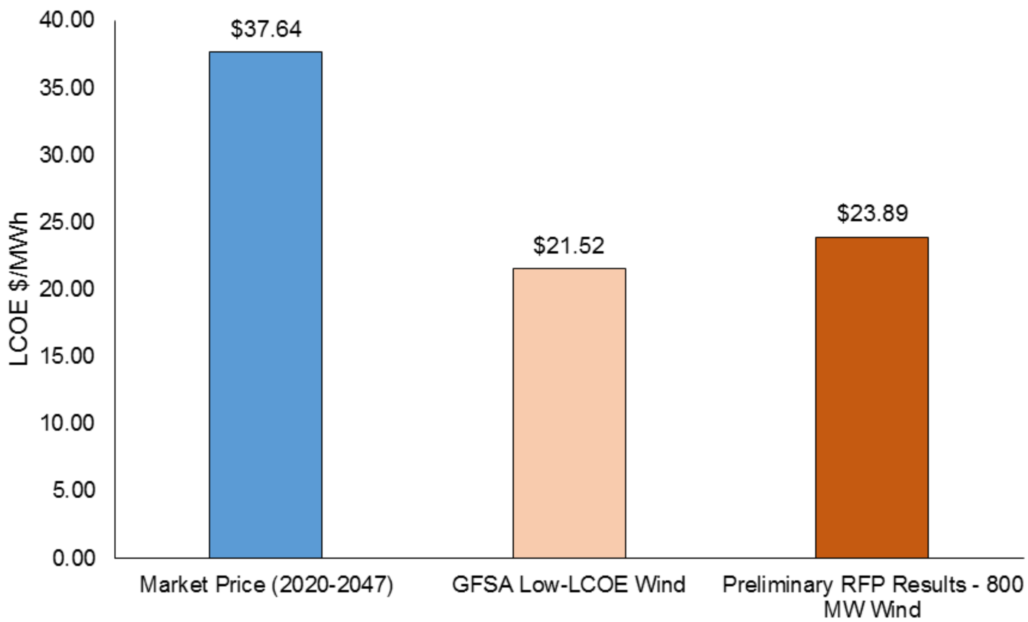
Figure 8: Plan 1 vs. Plan 2 Under Base, Low and High Market Prices



Q. DOES IT CONCERN YOU THAT EMPIRE WILL BE SELLING MORE ENERGY INTO THE SPP MARKET THAN ITS CUSTOMERS BUY OUT OF THE MARKET?

A. No, for a couple of reasons. First, Empire is well positioned within a wind-rich region to take advantage of decreasing wind turbine costs, improving wind technology performance, the PTC, and tax equity financing to significantly lower costs for its customers. Empire's GFSA and the preliminary RFP results indicate that Empire can produce wind energy at a substantial discount to market, today and into the future. Figure 9 shows a comparison of the Levelized Cost of Energy ("LCOE") of market priced power, low LCOE wind as referenced in the GFSA, and the LCOE of wind from the preliminary RFP results. I expect a direct correlation between customer savings and the amount of wind that is added.

Figure 9: LCOE of Wind Resources vs. Market Prices



Second, even in the unlikely case where the market price is below the LCOE of wind, I would expect that these net costs would be at least partially offset by lower production costs from other generation in the portfolio, as described in response to the previous question.

Q. WHY NOT BUILD MORE WIND THAN 800 MW IF EVERY INCREMENT OF WIND REDUCES COSTS TO EMPIRE CUSTOMERS?

A. For a couple of reasons. First, it likely would be difficult to transact for more than 800 MW of wind in the timeframe allotted to take full advantage of the PTC. Second, while we expect Empire customers to benefit from increasing amounts of wind ownership, at some point beyond 800 MW of wind additions, a low market price scenario may produce less savings than Plan 1 and increase overall customer costs.[17] This would be a scenario where the net costs of the additional wind are not offset by the lower costs of other Empire portfolio elements (e.g., the lower cost of the natural gas units). Finally, an additional 800 MW of wind limits the total capacity of Empire wind resources to peak load and means that approximately 50% of the energy that Empire expects to generate is from wind.

Q. HAVE OTHER UTILITIES MOVED TOWARD A 50% RENEWABLE ENERGY LEVEL?

A. Yes, many utilities are moving in that direction and at least one, MidAmerican, appears to have already have achieved it. As I describe earlier in this testimony, MidAmerican is expected to generate more than 90% of its customers' annual energy consumption by the end of 2020 from renewables, primarily from wind power,[18] and Xcel Energy is projecting that by 2027 47% of its generation will come from renewables.

Q. IS IT APPROPRIATE FOR A RELATIVELY SMALL-SIZED UTILITY LIKE EMPIRE TO MOVE TOWARD A CLEANER ENERGY FUTURE?

A. In my opinion, yes. Being relatively small I believe is an advantage to Empire in that it is able to pivot and significantly reduce customer costs with up to 800 MW of new wind.

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[17] In Plan 2, the low market scenario has a lower PVRR than the base scenario.

[18] https://www.midamericanenergy.com/wind-energy.aspx

f. SAVINGS FROM RETIRING ASBURY

Q. CAN YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY RELATED TO THE CUSTOMER SAVINGS BENEFIT FROM RETIRING ASBURY?

A. In the GFSA analysis, Empire estimated the benefit of retiring Asbury as $26M under the base case scenario[19]. These savings derive from avoiding expected capital and fixed operating costs in an environment where Asbury is delivering little margin in the SPP market. Retiring Asbury and building up to 800 MW of wind is expected to save Empire customers $325 million.

Q. CAN YOU SUMMARIZE STAFF WITNESS ROGERS' REBUTTAL TESTIMONY RELATED TO THE DECISION TO RETIRE ASBURY?

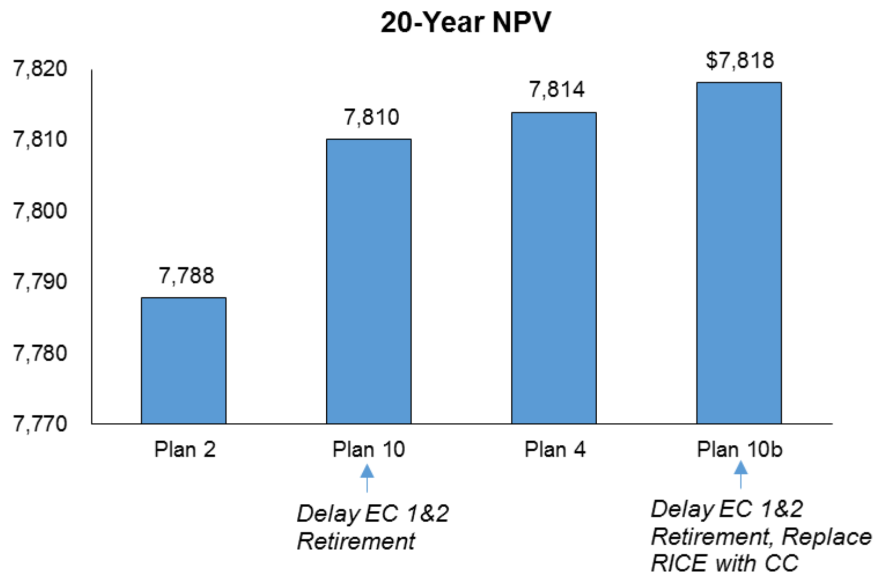
A. Mr. Rogers believes that retiring Asbury may not be cost effective for Empire, based on his review of the GFSA analysis and subsequent modeling runs performed by Empire at the request of Staff. (Rogers Reb., p. 9) Mr. Rogers compares Plan 2 and Plan 3 with Plan 10 and Plan 10b where Asbury is retained. Plan 10b is an alternate to Plan 4, where the Energy Center retirement is delayed, and instead of a reciprocating engine being built in 2035, a 200 MW combined cycle unit is built. It is Staff's position that due to the increased energy sales from the combined cycle relative to the reciprocating engine unit, that this plan would come out lower cost than both Plan 4 and Plan 2 from the GFSA.

[19] The $26 million in savings is from Plan 4b, which includes a correction to Plan 4.

Q. MR. ROGERS POSITS THAT PLAN 10B WILL BE LOWER COST THAN PLAN 2 ONCE THE MODELING IS COMPLETE. (ROGERS REB., P. 10) NOW THAT THE MODELING IS COMPLETE, WAS THAT TRUE?

A. No. Plan 10b is higher cost than both Plan 4 and Plan 2 from the GFSA, which is depicted in Figure 10 below:

Figure 10: 20-Year NPV of Plan 2, 4, 10, 10b

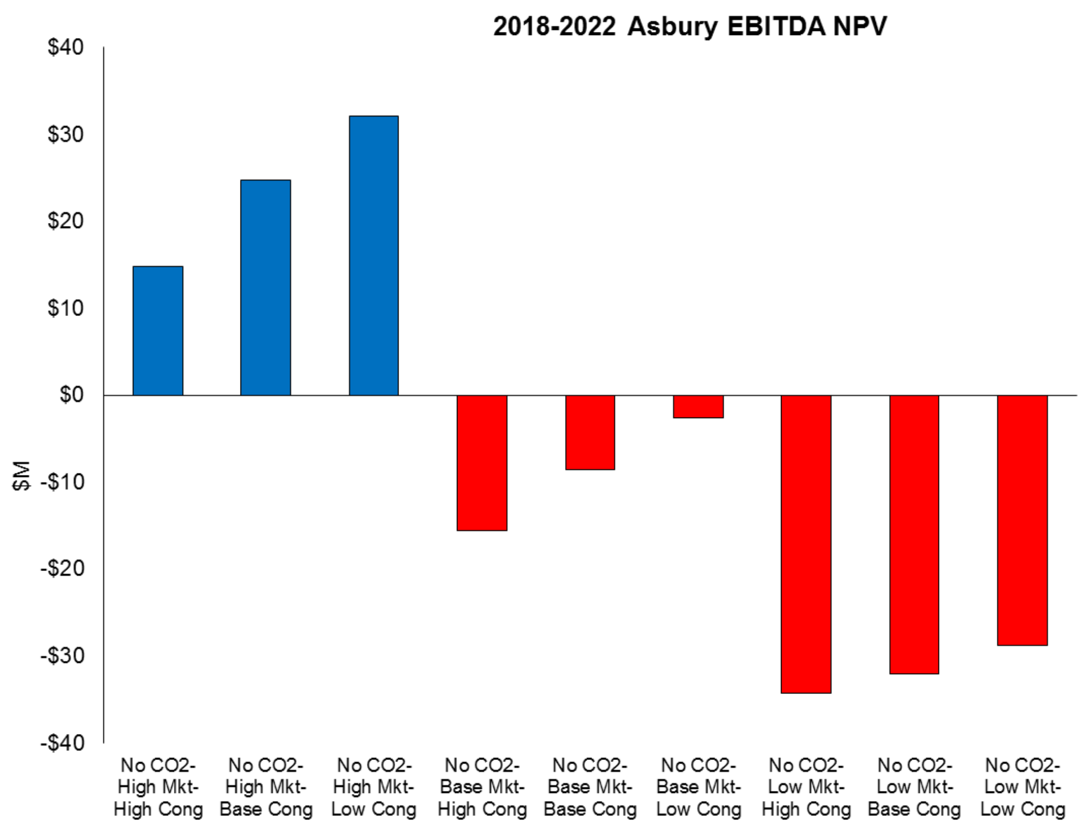


Plan 10b comes out higher cost than Plan 4, Plan 10 and Plan 2, on both a 20-year and 30-year NPV basis. Plan 10b does have more net sales into SPP, as the combined cycle unit dispatches more than the RICE unit, but results in higher overall costs as the higher SPP revenues are offset by fuel costs and energy margins are not able to cover other fixed and capitalized costs.

Q. BEYOND THE EXPECTED SAVINGS IN THE GFSA, WHAT ARE THE TRADE-OFFS OF RETIRING ASBURY?

A. While Asbury is an important part of the current Preferred Plan, based on current projections of gas and power prices, Asbury is projected to not generate enough revenue in the SPP market to cover just its variable and fixed operation and maintenance costs, without considering any additional capital, for three years, under many of the stochastic endpoints. This is depicted in the graphic below. Retiring Asbury and replacing it with a more economic generating resource would provide material savings to Empire customers.

Figure 11: Asbury EBITDA 2018-2022



Q. IS THERE ANY ECONOMIC BENEFIT TO DELAYING THE RETIREMENT OF ASBURY?

A. The only benefit to delaying Asbury would be if electricity prices were to rise precipitously, most likely due to an increase in natural gas prices or a tightening of the market, and Asbury could generate significant additional margins. However, in this case, Empire would benefit from owning a significant amount of wind and would therefore be appropriately hedged if gas ran less.

V. <u>ADDITIONAL ANALYSIS COMPLETED AT THE REQUEST OF PARTIES</u>

Q. CAN YOU DESCRIBE THE TYPE OF ADDITIONAL ANALYSIS THAT PARTIES HAVE REQUESTED FROM EMPIRE SINCE THE GFSA WAS FILED?

A. Party requests generally have fallen into 3 categories: (1) requests that have sought to test the robustness of the GFSA conclusions under different ranges for key uncertainties; (2) requests that have sought to evaluate alternative Plans to those run by Empire, and; (3) requests that have sought to evaluate the impact of tax reform.

Q. TO YOUR UNDERSTANDING, HAS EMPIRE RESPONDED TO ALL REQUESTS FOR ADDITIONAL ANALYSIS?

A. Yes. Empire has either responded to every request from a party for additional analysis, including those made through formal and informal data requests.

Q. HOW MANY ADDITIONAL ANALYSES WOULD YOU ESTIMATE EMPIRE HAS CONDUCTED AT THE REQUEST OF PARTIES?

A. Based on my review of the formal and informal data requests, I would estimate that Empire has developed 15-20 unique analyses at the request of parties.

Q. HAS THE ADDITIONAL ANALYSIS CHANGED EMPIRE'S RECOMMENDATION IN THE GFSA OF RETIRING ASBURY AND BUILDING UP TO 800 MW OF LOW LCOE WIND?

A. No. The additional analysis has only strengthened the conclusion that retiring Asbury and replacing it with up to 800 MW of wind will save Empire customers money relative to the 2016 IRP Preferred Plan. Plan 2 from the GFSA comes out as the lowest cost plan under both updated market price and updated tax reform scenarios, saving customers $281 million and $334 million under each scenario respectively. Plan 2 also continually comes out lower cost than many of the alternate plans that Staff requested.

Q. CAN YOU DESCRIBE THE ADDITIONAL ANALYSIS THAT EMPIRE COMPLETED FOR PARTIES THAT WAS NOT DESCRIBED ABOVE?

A. Staff and OPC requested numerous analyses to further test uncertainty around the time horizon, tax reform and load.

Variables Modified	Purpose of Analysis	Requesting Party
Corporate Tax Rate, Wind Inputs	Updated Tax Reform	MECG
Load – High and Low	Stochastic analysis around load	Staff
40 Year Time Horizon	40-Year End Effects	Staff

Empire also ran additional portfolio concepts at the request of parties, including different combinations of wind resource and DSM.

Q. CAN YOU DESCRIBE THE ADDITIONAL ANALYSIS YOU DEVELOPED TO REFLECT THE IMPACT OF TAX REFORM?

A. Yes. After the GFSA was filed in October 2017, the Tax Cut and Jobs Act of 2017 ("TCJA") was passed by Congress and signed by the President. The TCJA cuts corporate taxes to 21%, among other things. The primary impact on the GFSA is to lower customer rates and to potentially increase the cost of tax equity. Several parties requested that Empire update the results of the GFSA to reflect the impact of tax reform.

Q. DID EMPIRE RUN A SCENARIO THAT EVALUATED THE IMPACT OF TAX REFORM ON THE GFSA?

A. Yes. Empire updated the GFSA analysis to include the change in the corporate tax rate as part of the passage of tax reform in December 2017. The analysis included two major updates: (1) the effect that the new tax rate has on the overall revenue requirement for

Empire's customers, and; (2) the effect the new tax rate has on the availability of tax equity financing for the wind projects. The tax reform update resulted in a decrease in the PVRR for all nine plans from the GFSA by approximately $500M, depending on the plan. The savings of Plan 2 relative to Plan 1 increased from $325 million to $334 million, while the savings of Plan 3 increased from $172M to $258M (20-year NPV). The tax reform update resulted in an increase in capital cost for both the Low-LCOE and Mid-LCOE wind, due to a slight decline in the percentage of the tax equity financing (60% down to 54%), which is offset by lower income tax expense. All plans with new wind continue to provide significant savings versus the 2016 IRP Plan, despite the slight increase in effective capital costs.

Figure 12: 20 Year NPVRR - GFSA vs. Tax Reform

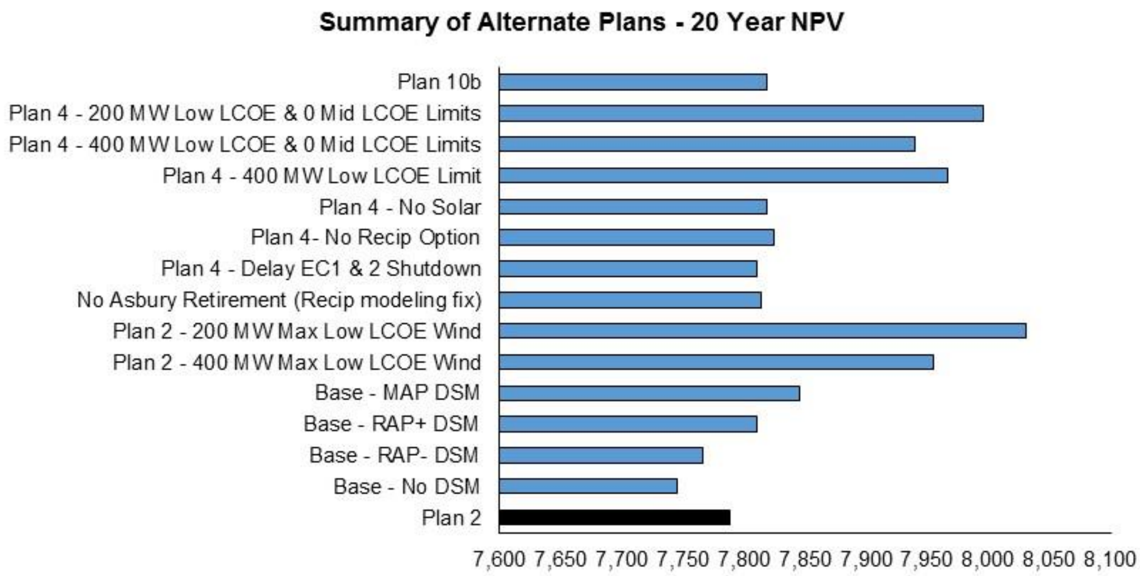
Q. HAS THE ANALYSIS OF TAX REFORM CHANGED EMPIRE'S RECOMMENDATION IN THE GFSA OF RETIRING ASBURY AND BUILDING UP TO 800 MW OF LOW LCOE WIND?

A. No. Plan 2 still creates significant savings of $334 million after accounting for tax reform.

Q. PLEASE SUMMARIZE GENERALLY THE RESULTS OF THE ADDITIONAL PLANS ANALYZED.

A. As Figure 13 illustrates, GFSA Plan 2 remains the lowest cost plan relative to all of these alternative plans, with the exception of the two base plans with lower levels of DSM (Plan 2-No DSM and Plan 2-RAP-DSM). Additionally, adding DSM increases costs for Plan 2 relative to the original Plan 2. The alternate plans that constrained the amount of wind built for Plans 2 and 4 likewise came out higher cost than the baseline. Finally, the alternate Plan 4 plans had various results. Delaying the Energy Center retirements came out less expensive than the original Plan 4, by $4 million. Replacing the RICE engine with a combustion turbine in 2035 resulted in a higher cost of $11 million (20-year) and $36 million (30-year). Replacing the RICE engine with a combustion turbine in 2035 *and* removing the solar unit resulted in a higher cost of $5 million (20-year) and $48 million (30-year).

Figure 123: Alternate Plans NPVRR (20-Year) vs. Plan 2



Q. HAS THE ANALYSIS OF THE ALTERNATE PLANS CHANGED EMPIRE'S RECOMMENDATION IN THE GFSA OF RETIRING ASBURY AND BUILDING UP TO 800 MW OF LOW LCOE WIND?

A. No. The Plan 2 from the GFSA still produces the most customer savings, with the exception of the Plan 2 scenarios that remove DSM. Moreover, the alternate scenarios reaffirm the conclusions of the GFSA: that adding 800 MW of wind is beneficial for Empire customers. For example, in all cases where the amount of wind built was constrained, the plans came out higher cost.

VI. <u>EMPIRE'S PROCESS FOR DEVELOPING THE GFSA</u>

Q. IN YOUR WORK IN THE INDUSTRY, ARE YOU FAMILIAR WITH THE APPROACHES USED BY OTHER VERTICALLY INTEGRATED INVESTOR-OWNED UTILITIES TO EVALUATE RESOURCE DECISIONS?

A. Yes. I have recently reviewed the IRP for most of the vertically integrated investor-owned utilities in the United States and am broadly knowledgeable on the approach and modeling systems used by utilities today. My experience is a result of: (1) directly supporting utilities in resource planning through market price forecasting, portfolio modeling, risk analysis, tradeoff analysis, and stakeholder support; as well as, (2) my leadership of CRA's retail rate forecasting service which involves an annual review of many utility IRPs to support a long-range retail rate forecast.

Q. CAN YOU PROVIDE A LIST OF THE UTILITY IRPS THAT YOU HAVE RECENTLY REVIEWED OR SUPPORTED?

A. Yes. In the last year, as part of CRA project work, I have reviewed or led the development of IRPs for utilities of the following utility holding companies: AEP, AES, Allete, Alliant, Black Hills Energy, CMS Energy, DTE Energy, Duke Energy, FirstEnergy, Macquarie (Puget, CLECO), MDU Resources, NiSource, Otter Tail Power, PacifiCorp, Southern Company, Tennessee Valley Authority, Vectren, Xcel Energy, and WEC.

Q. RELATIVE TO OTHER UTILITIES, HOW WOULD YOU CHARACTERIZE EMPIRE'S APPROACH TO RESOURCE PLANNING AND PREPARATION OF THE GFSA?

A. I would characterize Empire's resource planning approach to be consistent with, and in some cases, exceeding the industry standard. Empire employs an approach to resource planning, which was used to develop the GFSA that is similar to many other utilities.

Q. CAN YOU DESCRIBE MORE SPECIFICALLY WHAT ELEMENTS OF EMPIRE'S RESOURCE PLANNING APPROACH ARE CONSISTENT WITH OTHER UTILITIES YOU HAVE REVIEWED?

A. Yes. I assess Empire's resource planning approach along four dimensions that I believe are important to sound resource investment decisions: (1) decision framework; (2) model mechanics; (3) scenario structure; and, (4) assumptions development. In my opinion, Empire met or exceeded the industry standard in each of these areas in conducting the GFSA.

Q. CAN YOU DESCRIBE HOW EMPIRE'S DECISION FRAMEWORK MET OR EXCEEDED THE INDUSTRY STANDARD?

A. Yes. Empire uses the minimization of the present worth of long-run utility costs as the primary selection criteria in its IRP. Empire also assesses the risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans. Empire's focus on cost and risk in resource selection is consistent with industry best practices. Some utilities also consider additional factors such as sustainability or environmental attributes of the portfolio.

Q. CAN YOU DESCRIBE HOW EMPIRE'S MODEL MECHANICS MET OR EXCEEDED THE INDUSTRY STANDARD?

A. Yes. Empire relied on a modeling suite developed and operated by ABB for analyzing resource options. The modeling suite comprises primarily two models: a capacity optimization model and a production cost model. The capacity optimization model determines the resource plan that minimizes costs to Empire customers given a starting resource portfolio, a set of options and a set of constraints. Numerous utilities use the same or similar tools to the ABB capacity optimization model in their resource planning projects. The production cost model develops a detailed revenue requirement calculation for the optimized portfolio and any related scenarios. Likewise, numerous utilities use the same or similar tools to the ABB production cost model in their resource planning projects.

Q. CAN YOU DESCRIBE HOW EMPIRE'S SCENARIO STRUCTURE MET OR EXCEEDED THE INDUSTRY STANDARD?

A. Yes. All utility resource plans that I have reviewed recognize that evaluating uncertainty is a critical part of a resource planning exercise. I find that utilities employ a few different approaches here though. Some utilities begin with a base case scenario and then run sensitivities on key uncertainties, such as natural gas prices or technology costs. Other utilities will consider a range of scenarios or future 'states of the world' complemented with some one-off sensitivities. Finally, some utilities will begin with a base scenario and then run a set of probability-weighted scenarios to create a probability distribution around the expected case mean. Empire uses this third approach, which I find to be industry leading.

Q. WHY DO YOU CONSIDER AN APPROACH THAT USES STOCHASTIC ANALYSIS AS INDUSTRY LEADING?

A. Stochastic analysis structures a probability distribution around a base case expectation. This is particularly useful for describing with a certain level of confidence the range over which customer costs (or cost savings in the case of the GFSA) will fall. I find this approach to be more useful than scenarios or sensitivities alone for characterizing uncertainty in a resource plan. As one point of reference, the Indiana Utility Regulatory Commission ("IURC") released a report in 2017 that described deficiencies in certain utility resource filings because of their failure to include stochastics, which the IURC described as industry leading.[20]

Q. CAN YOU DESCRIBE HOW EMPIRE'S ASSUMPTIONS DEVELOPMENT MET OR EXCEEDED THE INDUSTRY STANDARD?

A. Empire relied on a combination of internal and external sources for developing assumptions to support the GFSA. This is consistent with the approach used by utilities that I have reviewed. Assumptions for market prices and technology costs are particularly important to the GFSA analysis. For assumptions on market prices Empire relied on forecasts produced by ABB. Using a reputable outside source, such as ABB, for market price forecasts is a common and reasonable approach. For assumptions on technology costs Empire relied on forecasts from an engineering firm. These were augmented by results of Empire's RFP. I likewise find the use of a third party forecast of technology costs to be a common and reasonable approach. Moreover, I find the use of a

[20] *See* Final Director's Report for the 2016 Integrated Resource Plans, https://www.in.gov/iurc/files/Director%27s%20IRP%20Report%20-%2011-2-2017%20Final.pdf.

competitive solicitation like Empire's RFP to validate technology cost assumptions within a decision model to be a leading practice.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF JAMES MCMAHON

COMMONWEALTH OF MASSACHUSETTS)
) ss
COUNTY OF SUFFOLK)

On the 12th day of March, 2018, before me appeared James McMahon, to me personally known, who, being by me first duly sworn, states that he is Vice President, Charles River Associates, and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

James McMahon

Subscribed and sworn to before me this 12th day of March, 2018

ANGELA M. CLOVEN
Notary Public - Notary Seal
State of Missouri
Commissioned for Jasper County
My Commission Expires: November 01, 2019
Commission Number: 15262659

Notary Public

My commission expires: Nov. 01, 2019