Exhibit No.:
Issues: *Generation Fleet Savings Analysis*
Witness: *John A. Rogers*
Sponsoring Party: *MO PSC Staff*
Type of Exhibit: *Rebuttal Testimony*
Case No.: *EO-2018-0092*
Date Testimony Prepared: *February 7, 2018*

MISSOURI PUBLIC SERVICE COMMISSION

COMMISSION STAFF DIVISION

REBUTTAL TESTIMONY

OF

JOHN A. ROGERS

EMPIRE DISTRICT, A LIBERTY UTILITIES COMPANY

CASE NO. EO-2018-0092

Jefferson City, Missouri
February 2018

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JOHN A. ROGERS

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REBUTTAL TESTIMONY

OF

JOHN A. ROGERS

EMPIRE DISTRICT, A LIBERTY UTILITIES COMPANY

CASE NO. EO-2018-0092

Q. Please state your name and business address.

A. My name is John A. Rogers, and my business address is Missouri Public Service Commission, P.O. Box 360, Jefferson City, Missouri 65102.

Q. What is your present position at the Missouri Public Service Commission ("Commission")?

A. I am the Utility Regulatory Manager in the Energy Resources Department of the Commission Staff Division.

Q. Please state your educational background and experience.

A. These are contained in Schedule JAR-r1.

Q. Would you please summarize the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond primarily to the direct testimony of Empire District, A Liberty Utilities Company ("Empire") witness James McMahon and present how Empire's proposed Customer Saving Plan ("CSP") represents a new approach to electric utility resource planning in Missouri and an electric utility business model that has never before been proposed to or approved by the Missouri Public Service Commission ("Commission"). Traditionally, electric utility resource planning has centered on having enough demand-side and supply-side resources to meet forecasted customer load under all conditions. If approved, however, the CSP will rely heavily upon making high levels of future long-term off-system sales to other utilities in the competitive electricity marketplace to offset capital costs of the CSP. The CSP would significantly increase equity cost[1] – paid by ratepayers – in the near term (10 years) to fully compensate a "tax equity partner," and is expected to only modestly reduce customers' bills primarily after 10 years when the "tax equity partner" has been paid in full. While customers are expected to realize a net savings from the CSP, customers' savings are very uncertain, because customers' savings are dependent upon the competitive electricity marketplace behaving over the next 20 to 30 years as it is presently modeled by Empire's analysts. I also discuss why the early retirement of the 186 MW Asbury coal plant, as proposed in the CSP, may not be in the best interest of Empire and its customers.

The CSP relies heavily on the experience of Liberty Utilities with tax equity financing. Through its CSP, Empire is seeking decisional pre-approval from the Commission to operate very much like a merchant generator[2] in the competitive and uncertain electricity marketplace, and to have much of the CSP financed by its ratepayers, who will largely not be using much of the energy output resulting from the CSP.

GENERATION FLEET SAVINGS ANALYSIS IN THE APPLICATION ("GFSA")

Q. Have you reviewed the direct testimony of Mr. McMahon, the GFSA, and the work papers in support of the GFSA?

A. Yes.

Q. What plans did Empire choose for its CSP?

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[1] Equity cost includes retained earnings for shareholders and all payments to the tax equity partner. Annualized Earnings Cost is the last line on the income statement for each plan in Empire's work papers for the GFSA.

[2] Merchant generators build power capacity on a speculative basis or acquire utility-divested plants and then market their output at competitive rates in unregulated markets.

A. Empire selected Plan 2 ("Preferred CSP") followed by Plan 3 ("Contingency CSP"), as summarized on page 8 lines 1 – 14 of Mr. McMahon's direct testimony:

> The analysis found that the lowest cost way for Empire to serve its load obligations over the next twenty to thirty years is to undertake a near-term strategy that builds up to 800 MW of wind strategically located wind in or near Empire's service territory in 2019 and 2020 and retires the Asbury coal plant in 2018 or 2019. Wind in regions with high capacity factors (hereafter referred to as "low-levelized cost of electricity" or "low- LCOE" wind) is expected to be lower cost for customers, but if Empire is constrained on the amount that can be built in these regions, additional wind in regions with lower capacity factors (hereafter referred to as "mid-LCOE" wind) is still cost effective. A plan **[Preferred CSP]** with 800 MW of low-LCOE wind is projected to realize a $325 million savings against the Preferred Plan from the 2016 IRP on a 20-year net present value of revenue requirements ("PVRR") basis and a $607 million savings on a 30-year PVRR basis. A plan **[Contingency CSP]** with 400 MW of low-LCOE wind and 400 MW of mid-LCOE wind is projected to realize a savings of $172 million on a 20-year PVRR basis and a savings of $420 million on a 30-year basis.

Q. What alternative resource plans did you compare in preparation for your testimony?

A. In my testimony, I compare the following alternative resource plans which are defined in more detail in Schedule JAR-r2:

- **Plan 1 (2016 IRP)** is Empire's 2016 IRP adopted preferred resource plan with 186 MW Asbury coal plant retired in 2035;
- **Plan 2 (Preferred CSP)** is 800 MW of low-LCOE wind and retire Asbury in 2018;
- **Plan 3 (Contingency CSP)** is 400 MW of low-LCOE wind and 400 MW of mid-LCOE wind and retire Asbury in 2018; and,

- **Plan 10 (Corrected Keep Asbury)** is 800 MW of low LCOE wind, retire 186 MW Asbury in 2035, add 167 MW reciprocating engine generator in 2035, and correct for an error in Plan 4 of approximately $65 million of additional annual costs associated with the reciprocating engine generation after 2035. See Schedule JAR-r3.

Q. Please provide the expected changes in the present value of revenue requirements[3] ("PVRR") for Plans 2, 3, and 10 relative to Plan 1 for the 10-year, 20-year, and 30-year planning horizons.

A. This information is contained in Table 1.

Table 1

SPP Marketplace Modeled in Application	Change in 10-Year, 20-Year and 30-Year PV Revenue Requirements for Plans 2, 3 and 10 Relative to Plan 1 ($ Millions) and (%)			
		10-Year	20-Year	30-Year
	Plan 2 PVRR	($71) -1.5%	($325) -4.0%	($607) -5.8%
	Plan 3 PVRR	$16 0.3%	($172) -2.1%	($420) -4.0%
	Plan 10 PVRR	$7 0.2%	($303) -3.7%	($601) -5.8%

Q. Please explain why you and Mr. McMahon both use PVRR to value and compare different resources plans.

A. 4 CSR 240-22.010(2)(B) requires that minimization of the present worth of long-run utility costs or present value of revenue requirements (PVRR) be the primary selection criterion when choosing the preferred resource plan. PVRR is calculated to modify

[3] All PVRR values in the GFSA use a discount factor of 6.59%, which is Empire's weighted average cost of capital.

the stream of annual revenue requirements of each resource plan to account for the time value of money[4] using Empire's weighted average cost of capital of 6.59% as the discount factor.

Q. Please describe how the PVRR values in Table 1 relate to expected customers' savings as a result of the CSP.

A. For all three (3) of the tables in my testimony, the PVRR amounts which are red and in parentheses represent a decreased amount of PVRR in millions of discounted dollars for a given plan relative to Plan 1 (2016 IRP) and a decrease in customers' bills (customers' savings). Any PVRR amounts that are black represent an increased amount of PVRR in millions of discounted dollars for a given plan relative to Plan 1 (2016 IRP) and an increase in customers' bills.

Q. Please summarize your analysis.

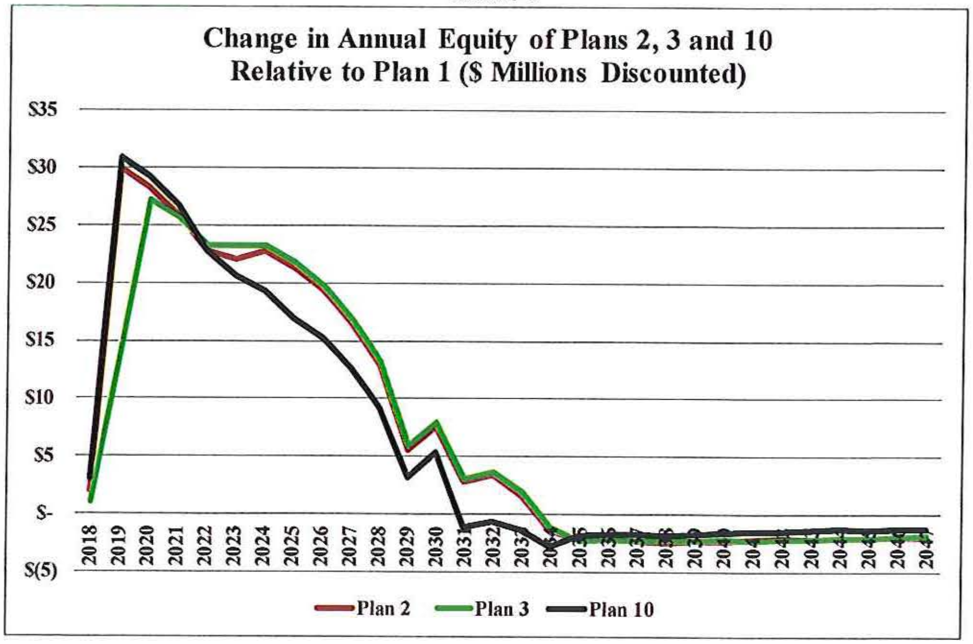
A. Expected customers' savings are minimal or possibly nonexistent in the first 10 years due to the large amount of equity cost resulting from the CSP during the first 10 years. Expected customers' savings increase once the equity partners achieve their expected returns.

Q. Please explain briefly and illustrate what you mean.

A. Chart 1 below illustrates the change in annual equity cost accounting for the time value of money for Plans 2, 3, and 10 relative to Plan 1 in discounted dollars. These annual equity cost amounts include retained earnings for shareholders as well as the cost to ratepayers for the contract with a tax equity partner, discussed on page 14, line 1 through page 17 line 4 of direct testimony of Empire witness Todd Mooney.

[4] The time value of money is the idea that money available at the present time is worth more than the same amount in the future due to its potential earning capacity. This core principle of finance holds that, provided money can earn interest, any amount of money is worth more the sooner it is received.

Chart 1



Q. Has Staff estimated the present value ("PV") of annual equity cost amounts for the 10-year, 20-year, and 30-year planning horizons for Plans 2, 3, and 10 relative to Plan 1? And, if so, what are those amounts?

A. Yes. Table 2 below contains the change in 10-year, 20-year, and 30-year present value of annual equity cost and PVRR for Plans 2, 3, and 10 relative to Plan 1 in millions of discounted dollars and in percentages values.

continued on next page

Table 2

SPP Marketplace Modeled in Application	Change in 10-Year, 20-Year and 30-Year PV Equity Cost and PV Revenue Requirements for Plans 2, 3 and 10 Relative to Plan 1 ($ Millions)			
		10-Year PV	20-Year PV	30-Year PV
	Plan 2 PV Equity Cost	$198	$222	$202
	Plan 2 PVRR	($71)	($325)	($607)
	Plan 3 PV Equity Cost	$184	$210	$190
	Plan 3 PVRR	$16	($172)	($420)
	Plan 10 PV Equity Cost	$184	$191	$178
	Plan 10 PVRR	$7	($303)	($601)
	Percentage Change in 10-Year, 20-Year and 30-Year PV Equity Cost and PV Revenue Requirements for Plans 2, 3 and 10 Relative to Plan 1			
		10-Year PV	20-Year PV	30-Year PV
	Plan 2 PV Equity Cost	28.2%	17.3%	12.0%
	Plan 2 PVRR	-1.5%	-4.0%	-5.8%
	Plan 3 PV Equity Cost	26.2%	16.4%	11.3%
	Plan 3 PVRR	0.3%	-2.1%	-4.0%
	Plan 10 PV Equity Cost	26.2%	14.9%	10.6%
	Plan 10 PVRR	0.2%	-3.7%	-5.8%

Q. How does the $222 Million for Plan 2 PV Equity Cost for 20-Years in Table 2 relate to the red Annual Equity Cost line in Millions of Discounted Dollars in Chart 1?

A. While the Annual Equity Cost data in Chart 1 represents equity cost per year, the PV Equity Cost in Table 2 represents the total of the equity cost per year over 10, 20, and 30-years. The PV Equity Cost is calculated by summing each year's Annual Equity Cost. For example, the $222 Million in Table 2 is equal to the sum of the twenty (20) Annual Equity Cost amounts represented by the red line for Millions of Discounted Dollars for 2018 – 2037 in Chart 1.

Q. What do you conclude from the data in Table 2?

A. Plan 2 (Preferred CSP) is expected to result in customers' savings of 1.5%, 4.0%, and 5.8% for 10 years, 20 years, and 30 years, respectively, compared to the

28.2%, 17.3% and 12.0% increase in present value of annual equity cost for each time period. Plan 3 (Contingency CSP) is expected to result in only slightly lower present value of annual equity cost compared to Plan 2 (Preferred CSP) for 10 years, 20 years, and 30 years, respectively. However, Plan 3 (Contingency CSP) is also expected to result in lower customers' savings of 0.3%, 2.1%, and 4.0% for 10 years, 20 years, and 30 years, respectively, compared to 1.5%, 4.0%, and 5.8% expected customers' savings for each time period for Plan 2 (Preferred CSP).

The comparison of Plan 2 (Preferred CSP) and Plan 3 (Contingency CSP) for 10 years, 20 years, and 30 years demonstrates how sensitive proposed customers' savings (as measured through PVRR) are to the levelized cost of electricity[5] for the wind resources that are ultimately chosen and constructed, should the CSP be implemented.

EARLY RETIREMENT OF ASBURY

Q. How do the results of Plan 10 impact Staff's view of the CSP's planned early retirement of the 186 MW Asbury coal plant?

A. A review of Table 2 and Plan 10 (Corrected Keep Asbury) results causes Staff to question the decision to retire Asbury early.

Q. Please explain.

A. The decision to retire Asbury early should not be made until after Empire has determined which wind resources it will actually construct for the CSP. Even with the 2019 $20 Million investment to bring Asbury into compliance with Environmental Protection

[5] The levelized cost of electricity (LCOE) is the net present value of the unit-cost of electricity over the lifetime of a generating asset. It is often taken as a proxy for the average price that the generating asset must receive in a market to break even over its lifetime. From Mr. McMahon's direct testimony on page 31 lines 17 – 18: The levelized cost of electricity is estimated to be $21.52/MWh for Low-LCOE wind (Plan 2) and $29.71/MWh for Mid-LCOE wind (Plan 3).

Agency regulations, Plan 10 (Corrected Keep Asbury) performs far better in terms of expected customers' savings than Plan 3 (Contingency CSP) and very nearly the same as Plan 2 (Preferred CSP) for the 20-year and 30-year planning horizons.

Later in this testimony, Chart 3 indicates that Plan 10 (Corrected Keep Asbury) has higher annual customers' savings (lower annual revenue requirement) than Plan 2 (Preferred CSP) and Plan 3 (Contingency CSP) in every year from 2026 through 2047.

Q. Can Plan 10 be improved such that there is an even stronger case for keeping Asbury in service until 2035?

A. Yes. Plan 10's inclusion of a 167 MW reciprocating internal combustion engine in 2035 causes Plan 10 to be unnecessarily costly and to decrease potential off-system sales revenue ("OSSR") compared to a combined cycle gas generator ("CC"). If Empire were to replace the 167 MW reciprocating internal combustion engine with more economical supply-side or demand-side resources, customers' savings resulting from a modified Plan 10 could be even greater.

Q. Has Staff notified Empire of this concern?

A. As part of its Data Request No. 0014, Staff requested that the Plan 4 be modified so that the 167 MW reciprocating engine generator(s) is replaced with more economical supply-side resources and/or demand-side resources, e.g., 100 MW CC and demand-side programs/demand-side rates. At this time Staff has not received a response from Empire with its analysis of this resource plan.

Also, on February 6, 2018, Staff requested (through Staff Data Request No. 0014.1) that a Plan 10b be developed to further improve Plan 10 by adding a 200 MW combined cycle natural gas generator in 2035 (when Asbury is retired) instead of the much more expensive and more inefficient 167 MW reciprocating internal combustion engine which is now in Plan 10. Staff expects that Empire's response to Staff Data Request No. 0014.1 will result in a Plan 10b which has customers' savings for both the 20-year and 30-year planning horizons relative to Plan 2 (Preferred CSP). In other words, Staff is expecting Plan 10b to perform better (save customers more on their bills) than Plan 2 (Preferred CSP).

HIGH WIND AND LOW COAL SCENARIO

Q. How important is Empire's integrated resource modeling of the High Wind and Low Coal scenario compared to the CSP to evaluate the impact on the equity partners and the customers' savings?

A. The modeling is very important. Currently, SPP has 32 GW of wind generation in its queue.[6] Additionally, western states will be joining the SPP, changing the current SPP generation mix.[7] It is likely that Empire will face a high wind and low coal scenario going forward. Therefore, it is important to model customers' savings on a more realistic prediction of the future electricity marketplace. See Schedule JAR-r3 for more information on the High Wind and Low Coal scenario modeling.

Q. How does a High Wind and Low Coal scenario impact the analysis of the CSP?

A. With an additional 9 GW of wind in the SPP over the forecast period and retirement of an additional 1.8 GW of coal in the SPP, the market price of electricity is expected to be ~5-7% lower in later years, which significantly reduced expected customers'

[6] https://www.rtoinsider.com/spp-wind-penetration-39074/.
[7] https://www.utilitydive.com/news/mountain-west-transmission-group-moves-to-join-spp/505666/.

savings from the CSP. There will undoubtedly be changes and disruptions to the electricity marketplace over the next 20 years and longer, many of which cannot be predicted today.

Table 3 below contains Staff's present value of annual equity cost and PVRR values for a High Wind and Low Coal scenario for Plans 2 and 3 relative to Plan 1.

Table 3

SPP Marketplace Modeled for High Wind and Low Coal Scenario	High Wind and Low Coal Scenario Change in 10-Year, 20-Year and 30-Year PV Equity Cost and PV Revenue Requirements for Plans 2 and 3 Relative to Plan 1 ($ Millions)			
		10-Year PV	20-Year PV	30-Year PV
	Plan 2 PV Equity Cost	$119	$189	$167
	Plan 2 PVRR	($20)	($160)	($455)
	Plan 3 PV Equity Cost	$107	$179	$157
	Plan 3 PVRR	$18	($48)	($303)
	High Wind and Low Coal Scenario Percentage Change in 10-Year, 20-Year and 30-Year PV Equity Cost and PV Revenue Requirements for Plans 2 and 3 Relative to Plan 1			
		10-Year PV	20-Year PV	30-Year PV
	Plan 2 PV Equity Cost	18.5%	16.5%	10.4%
	Plan 2 PVRR	-0.5%	-2.2%	-4.5%
	Plan 3 PV Equity Cost	16.6%	15.7%	9.8%
	Plan 3 PVRR	0.4%	-0.6%	-3.0%

As can be seen by Table 3, the range[8] of expected customer savings over 20 years from the High Wind and Low Coal scenario is $48 Million for Plan 3 (Contingency CSP) to $160 Million for Plan 2 (Preferred CSP), compared to the much higher expected customers' savings range of $172 Million for Plan 3 (Contingency CSP) to $325 Million for Plan 2 (Preferred CSP) modeled using more favorable electricity marketplace conditions.

[8] Plan 3 results are the low end of the range and Plan 2 results are the high end of the range.

This demonstrates how sensitive customers' savings are to less favorable electricity marketplace conditions that cause market prices to be lower.

RELIANCE ON OFF-SYSTEM SALES TO CREATE CUSTOMER SAVINGS

Q. Is it important to also analyze annual SPP sales when calculating the PVRR for each plan?

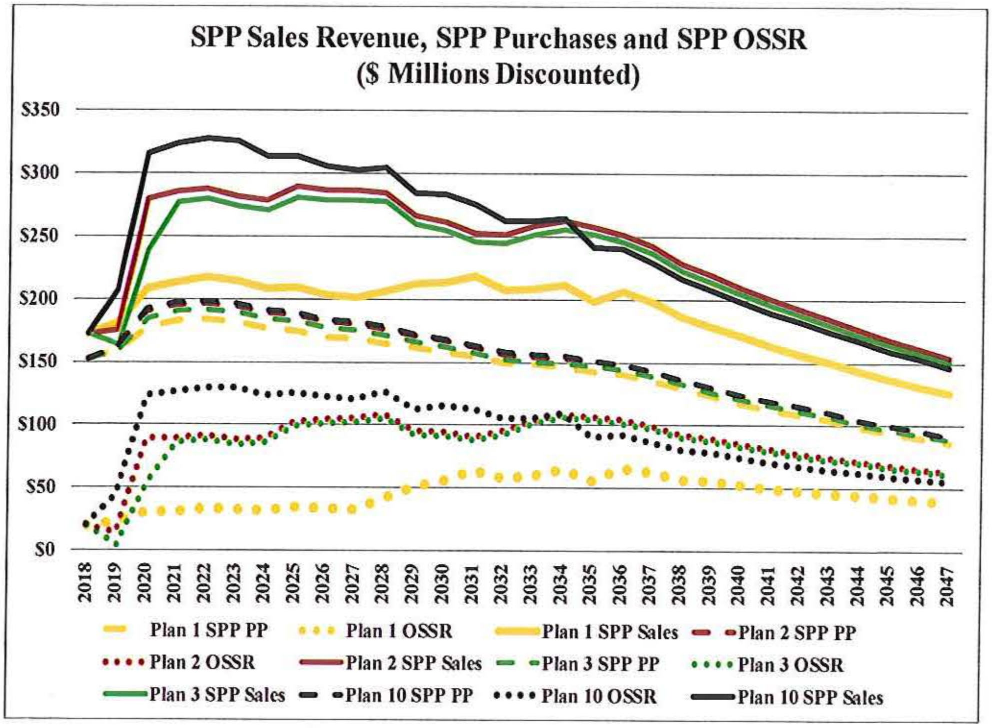
A. Yes. Annual SPP Sales directly impact the calculation of PVRR for each plan. Empire offers to SPP all of its available generation resources for SPP's "next day" operation of its Integrated Marketplace ("IM"). Each generating resource is offered daily by Empire at a generator-specific price per kWh. During the next day, Empire receives revenue whenever one of its generators is selected and run by SPP as a cost-effective generator ("SPP Sales"). Empire then purchases energy from the IM to meet its retail customers' load requirements, in other words, the SPP purchased power ("SPP PP"). Off-system sales revenue (OSSR) represents the revenue Empire receives for energy it generates over and above the load requirements of its captive retail customers. OSSR is simply SPP Sales minus SPP PP.

Q. What are the expected annual costs and annual revenues for Empire's energy sales to SPP (SPP Sales), Empire's energy purchases from SPP for Empire's retail customers (SPP PP), and Empire's off-system energy sales to other utilities in the SPP (OSSR) for Plan 1 (2016 IRP), Plan 2 (Preferred CSP), Plan 3 (Contingency CSP), and Plan 10 (Corrected Keep Asbury)?

A. This information[9] is in Chart 2 in discounted dollars for the 30-year planning horizon.

[9] Plan 2 SPP PP is hard to see in Chart 2, because the red dashed line for the Plan 2 SPP PP is overshadowed by the black dashed lines for the Plan 10 SPP PP.

Chart 2



Q. Please discuss the significance of the information in Chart 2.

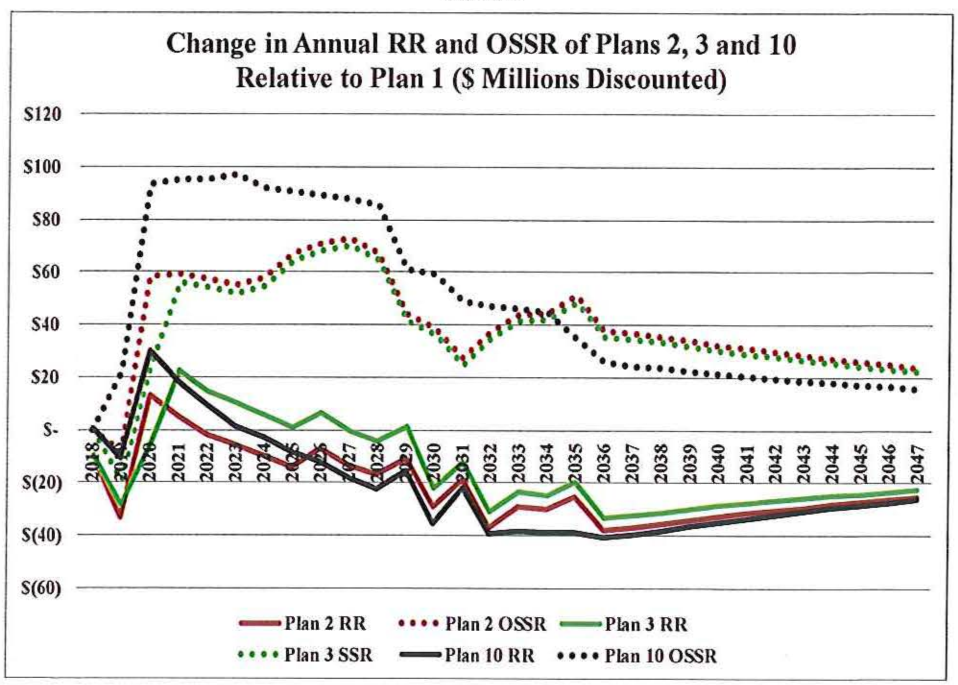
A. Chart 2 shows that for all four plans, the annual SPP purchased power (SPP PP) is approximately equal in any given year. This is expected. While the volume of Empire's retail load is unaffected by the alternative plan being evaluated, the SPP PP will be impacted somewhat by the cost of the energy for the various plans. Note that Plan 1 (2016 IRP) results in the lowest annual SPP PP cost for customers.

However, Plans 2, 3, and 10 have significantly higher levels of SPP Sales and OSSR when compared to Plan 1, and this is especially true during the first 10 years of the 800 MW of wind production in Plans 2, 3, and 10.

Q. What is the relationship of annual OSSR to annual PVRR for Plans 1, 2, 3, and 10?

A. The relationship of annual OSSR to annual customers' savings (lower annual RR) for Plans 1, 2, 3, and 10 is provided in Chart 3 in discounted dollars. Chart 3 demonstrates the mirror-like or direct relationship between annual OSSR and annual customers' savings (lower annual RR). During the first 10 years, while higher levels of SPP sales and OSSR would typically also mean greater savings achieved through a lower RR, the OSSR offset much of the large amount of annual equity costs - due primarily to the tax equity partner payments - such that there are little, if any, expected customers' savings for this time period. During years 11 through 30 - following full payment to the tax equity partner - there appears to be a very close relationship between the amount of annual OSSR and annual customers' savings for Plans 2, 3, and 10 relative to Plan 1.

Chart 3



Q. What factors can decrease OSSR?

A. OSSR will decrease whenever the amount (kWh) of off-system sales decreases and/or the market price received for the off-system sales decreases.

Q. Please provide an example of how decreased off-system sales and/or decreased market prices will decrease OSSR and directly impact customers' savings.

A. A good example is the High Wind and Low Coal scenario discussed earlier in my testimony and quantified in Table 3. The High Wind and Low Coal scenario includes an additional 9 GW of low cost wind generation in the SPP and resulted in an approximate 5 – 7% reduction in market prices in later years and caused an 8.0% reduction in 20-year PVRR for Plan 2 (Preferred CSP) and an 48.4% reduction in 20-year PVRR for Plan 3 (Contingency CSP).

Q. Does Mr. McMahon agree that reliance on off-system sales to pay for the CSP is risky?

A. Yes. On page 23 line 4 of his direct testimony, Mr. McMahon acknowledges that relying solely on off-system sales to manage costs introduces risk.

CSP REPRESENTS A NEW BUSINESS MODEL FOR EMPIRE

Q. How has Liberty Power developed and financed its interests in the 750 MW of wind projects referred to on page 17, lines 10 – 11 of Todd Mooney's direct testimony?

A. Liberty Power's interest in each of five (5) wind projects - which total 750 MW - is entirely financed through Algonquin Power & Utilities Corporation subsidiary ownership interest (Class B Shares). Further, all 750 MW are operating as independent merchant generators in the competitive electricity marketplace. See Schedule JAR-r4 and Schedule JAR-r5.

Q. How is Empire's CSP different from the 750 MW of wind referred to on page 17 lines 10-11 of Todd Mooney's direct testimony?

A. First, Empire's CSP is a single plan with 800 MW of wind, which is greater than the 750 MW of wind resulting from five separate wind projects.

Second, Empire's CSP will be financed by Empire's ratepayers (through new debt and equity offerings) and tax equity partner, while Liberty financed its wind projects through shareholder funds, which poses a much higher risk for the shareholder. Empire's proposed financing shifts the risk away from the shareholders and causes ratepayers to bear the risk of increased rates because the CSR relies heavily on future long-term off-system sales to manage costs.

As a regulated utility in Missouri, Empire has planned, constructed, and operated its utility business to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, to serve its retail customers' load. To the extent Empire is able to make off-system sales each day in the IM, it is expected to do so and to flow the OSSR through its fuel adjustment clause ("FAC").

However, in contrast to Empire's current adopted preferred resource plan (2016 IRP), Plan 2 (Preferred CSP) and Plan 3 (Contingency CSP) require much higher levels of expected annual OSSR in the competitive electricity marketplace in order to achieve the expected annual customers' savings in the CSP over 30 years. The CSP is inherently risky for customers as evidenced by the expected results of the High Wind and Low Coal scenario, which is just one of countless possible future scenarios which may negatively impact expected customers' savings.

CONCLUSION

Q. As a result of your analysis of the GFSA and your rebuttal testimony, how would you characterize the CSP, and what is your recommendation regarding the CSP?

A. Empire is seeking approval from the Commission for Empire to operate very much like a merchant generator in the competitive electricity marketplace (SPP). Because of the CSP's payments to the tax equity partner, little, if any, customers' savings are expected during most, if not all, of the first 10 years of the CSP, depending upon the levelized cost of electricity for the wind resources that are ultimately constructed. While Plan 10 does not present a compelling case for retiring Asbury early, Staff anticipates that Empire's response to Staff Data Request No. 0014.1 will result in a plan to keep Asbury in service until 2035 because doing so will result in greater customers' savings over 20 years and 30 years. The rebuttal testimony of Staff witness Natelle Dietrich outlines various scenarios for Commission consideration when deciding if the proposed CSP, or another alternative, is an appropriate business model for a regulated electric utility in Missouri.

Q. Does this conclude your testimony?

A. Yes, it does.

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 JOHN A. ROGERS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, John A. Rogers and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Rebuttal Testimony; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

John A Rogers
John A. Rogers

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 7th day of February, 2018.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 20, 2019
Commission Number: 15207377

Educational Background and Work Experience of John A. Rogers

I have a Master of Business Administration degree from the University of San Diego and a Bachelor of Science degree in Engineering Science from the University of Notre Dame. My work experience includes 34 years in energy utility engineering, system operations, strategic planning, regulatory affairs, general management and management consulting. From 1974 to 1985, I was employed by San Diego Gas & Electric with responsibilities in gas engineering, gas system planning and gas operations. From 1985 to 2000, I was employed by Citizens Utilities primarily in leadership roles for gas operations in Arizona, Colorado and Louisiana. From 2000 to 2003, I was an executive consultant for Convergent Group (a division of Schlumberger) providing management consulting services to energy utilities. From 2004 to 2008, I was employed by Arkansas Western Gas and was responsible for strategic planning and resource planning. I have provided expert testimony before the California Public Utilities Commission, Arizona Corporation Commission, Arkansas Public Service Commission and Missouri Public Service Commission in general rate cases, applications for special projects, gas resource plan filings, electric resource plan filings, demand-side management programs and demand-side programs investment mechanism cases. I have been employed by the Missouri Public Service Commission since December 2008 and am responsible for the Commission Staff's review of and recommendations concerning electric utility resource planning, demand-side management programs, demand-side programs investment mechanisms, and fuel adjustment clauses.

John A. Rogers
Testimony, Reports and Rulemakings

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

File Number	Company	Issues
ER-2010-0036	Ameren Missouri	Fuel Adjustment Clause Demand-Side Programs (DSM) DSM Cost Recovery
EX-2010-0368 EW-2010-0254	Missouri Public Service Commission	Missouri Energy Efficiency Investment Act Rulemaking
EX-2010-0254 EW-2009-0412	Missouri Public Service Commission	Electric Utility Resource Planning Rulemaking
EO-2009-0237	KCP&L Greater Missouri Operations Company	Electric Utility Resource Planning Compliance Filing
ER-2009-0090	KCP&L Greater Missouri Operations Company	Fuel Adjustment Clause
ER-2010-0355	Kansas City Power and Light	DSM Cost Recovery Fuel Switching
ER-2010-0356	KCP&L Greater Missouri Operations Company	Fuel Adjustment Clause DSM Cost Recovery Fuel Switching
AO-2011-0035	All Electric Utilities	DSM Status Report
EO-2011-0066	Empire District Electric Company	Electric Utility Resource Planning Compliance Filing
ER-2011-0028	Ameren Missouri	DSM Cost Recovery
EO-2011-0271	Ameren Missouri	Electric Utility Resource Planning Compliance Filing
EO-2012-0009	KCP&L Greater Missouri Operations Company	Demand-side Programs Investment Mechanism
EO-2012-0142	Ameren Missouri	Demand-side Programs Investment Mechanism

John A. Rogers
Testimony, Reports and Rulemakings

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION (cont.)

File Number	Company	Issues
ER-2012-0166	Ameren Missouri	DSM Cost Recovery Demand-side Programs Investment Mechanism
ER-2012-0174	Kansas City Power & Light	DSM Cost Recovery
ER-2012-0175	KCP&L Greater Missouri Operations Company	DSM Cost Recovery Demand-side Programs Investment Mechanism
ER-2012-0345	Empire District Electric Co.	DSM Cost Recovery
EO-2012-0323	Kansas City Power & Light	Electric Utility Resource Planning Compliance Filing
EO-2012-0324	KCP&L Greater Missouri Operations Company	Electric Utility Resource Planning Compliance Filing
EO-2013-0537	Kansas City Power & Light	Electric Utility Resource Planning Annual Update
EO-2013-0538	KCP&L Greater Missouri Operations Company	Electric Utility Resource Planning Annual Update
EO-2013-0547	Empire District Electric Co.	Electric Utility Resource Planning Compliance Filing
EX-2014-0205	Dogwood Energy, LLC	Rulemaking Petition
EO-2014-0095	Kansas City Power & Light	Demand-side Programs Investment Mechanism
EO-2015-0084	Ameren Missouri	Electric Utility Resource Planning Compliance Filing
EO-2015-0254	Kansas City Power & Light	Electric Utility Resource Planning Compliance Filing
EO-2015-0252	KCP&L Greater Missouri Operations Company	Electric Utility Resource Planning Compliance Filing

EO-2015-0055	Ameren Missouri	Demand-side Programs Investment Mechanism
EO-2015-0240	Kansas City Power & Light	Demand-side Programs Investment Mechanism
EO-2015-0241	KCP&L Greater Missouri Operations Company	Demand-side Programs Investment Mechanism
EO-2016-0223	Empire District Electric Co.	Electric Utility Resource Planning Compliance Filing
ER-2016-0156	KCP&L Greater Missouri Operations Company	Annualized Sales for Energy Efficiency
ER-2016-0285	Kansas City Power & Light	Annualized Sales for Energy Efficiency

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

Docket Number	Company	Issues
07-079-TF	Arkansas Western Gas	Arkansas Weatherization Program
07-078-TF	Arkansas Western Gas	Initial Energy Efficiency Programs
07-041-P	Arkansas Western Gas	Special Contract
06-028-R	Arkansas Western Gas	Resource Planning Guidelines for Electric Utilities
05-111-P	Arkansas Western Gas	Gas Conservation Home Weatherization Program

The Empire District Electric Company

Case No. EO-2018-0092

YEAR	Plan 1 (2016 IRP)	Plan 2 Base - 800 MW Wind Limit	Plan 3 Base - 400 MW Low LCOE Wind Limit	Plan 10 Base with Asbury
2018	Update Asbury	Retire Asbury	Retire Asbury	Update Asbury
2019		800 MW Low LCOE Wind	400 MW Low LCOE Wind	800 MW Low LCOE Wind
2020			400 MW Mid LCOE Wind	
2021				
2022				
2023	Retire EC1	Retire EC1	Retire EC1	Retire EC1
2024				
2025		100 MW CC	100 MW CC	
2026	Retire EC2	Retire EC2	Retire EC2	Retire EC2
2027				
2028				
2029	100 MW Wind 100 MW CC			
2030				100 MW Solar
2031	150 MW Wind	100 MW Solar	100 MW Solar	100 MW Solar
2032		100 MW CC	100 MW CC	
2033	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11
2034				
2035	200 MW CC			167 MW Recip
2036				
2037				

Memorandum

To:	The Empire District Electric Company
From:	James McMahon, Vice-President, Charles River Associates
Date:	1/19/2018
Subject:	Updated Analysis Results

The Empire District Electric Company, following the submission of the Generator Fleet Savings Analysis (GFSA), performed several additional analyses to evaluate the impact of different assumptions on the nine plans established in the GFSA and to assess the performance of alternative potential plans. The different analyses are summarized below. Overall, the results of these analyses re-affirm the conclusion in the GFSA that adding 800 MW of wind to the portfolio will provide savings versus the plan identified in the 2016 IRP.

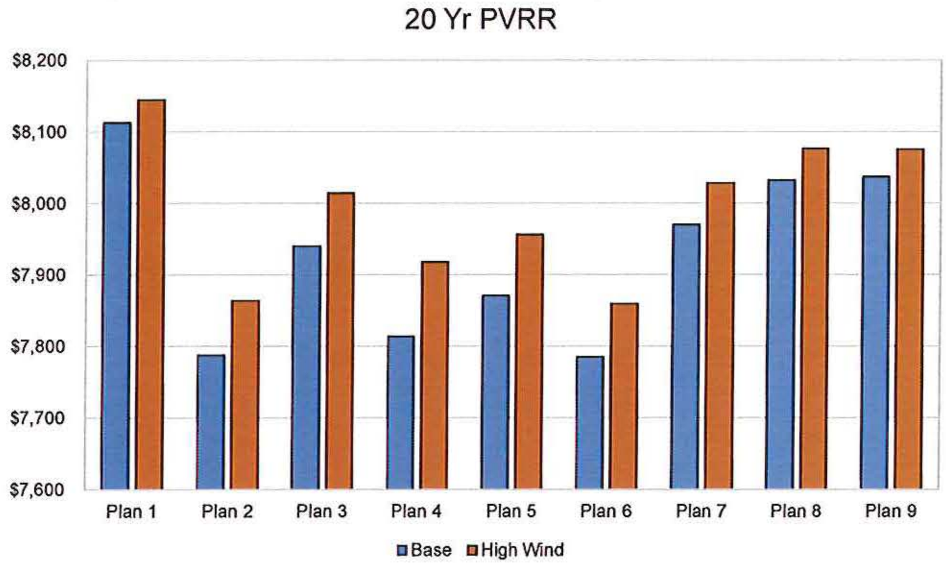
Additional Stakeholder Analysis, prepared January 2018

Analysis	New External Assumptions?	New Plans?	Comments
Alternative Assumption: High Wind, Less Coal	Yes, market price	No	Plans 1-9 evaluated against different SPP market outlook
Alternative Assumption: 40-yr Time Horizon	Yes, time horizon	No	Plans 1-9, with Base Case analysis time frame extended by 10 years
Alternative Assumption: Corporate Tax Change	Yes, tax policy	No	Plans 1-9 evaluated under original Base Case, but with new tax assumptions
Alternative Assumption: Load uncertainty – integrated into stochastics	Yes, load uncertainty	No	Plans 1-9, evaluated with a new critical uncertain factor (load) in addition to original set of three; new stochastic analysis with 54 total endpoints
Additional Plans: additional constraints and specific forced portfolio changes	No	Yes	8 new plans developed ("Plans 10-17"), run against the original Base Case
Additional Plans: optimized for DSM scenarios	No	Yes	4 new plans developed ("Plans 18-21"), run against the original Base Case

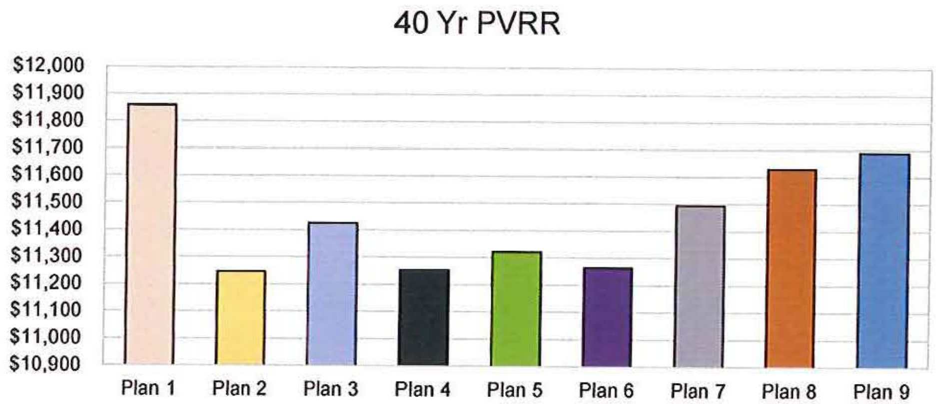
The accompanying file, "Attachment Additional GFSA Scenarios Results.xlsx" contains the details of the results for the various analyses. The primary findings are summarized as follows:

- *Alternative Assumption with high wind and less coal* – All nine plans were evaluated with an updated SPP market price forecast. The updated high wind case adds an additional 9 GW of wind to SPP over the forecast period and retires an additional 1.8 GW of coal in

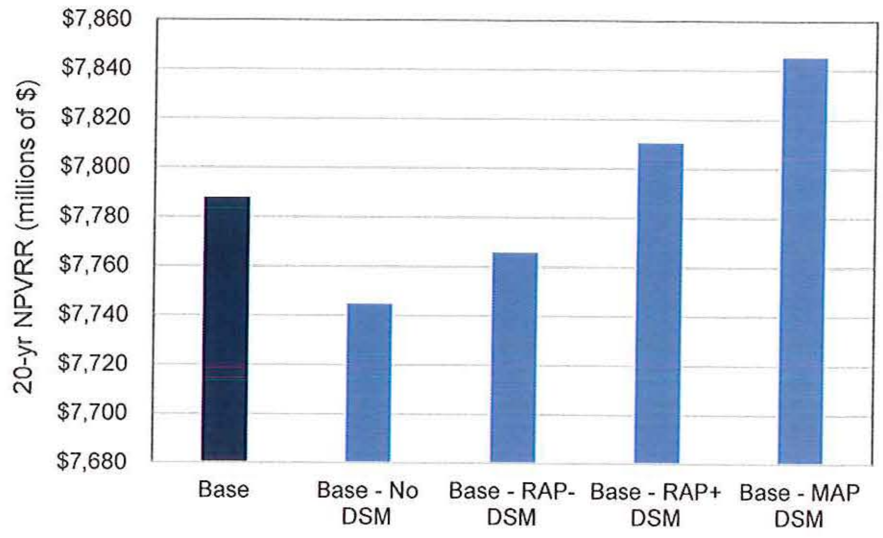
SPP. This resulted in a decrease in the market price of ~5-7% in the later years. The high wind / low coal pricing scenario resulted in increased costs for all plans, because Empire is expected to generate more electricity than native load in all cases. The plan most impacted was Plan 4 (retaining Asbury with 800 MW of wind), given that it has the highest generation. Plan 2 with 800 MW of wind was also affected more than the plans with lower amounts of wind, but still had the lowest cost overall. This is shown below for the 20-year NPVRR. The 30-year outlook is similar.



- *Alternative Assumption with 40-year time horizon* – The nine original plans were evaluated over a 40-year time period in addition to the original 20-year and 30-year frameworks. In extending the period to 40 years, additional natural gas capacity was added in each plan after the wind projects came offline or as reserve margin requirements demanded. Although Plan 2 requires additional capital expenditures versus Plan 1 at the end of the 40-year time horizon to replace the retiring 800 MW wind capacity, the additional costs do not meaningfully impact the PVRR. Overall, the 40-year study confirms the same plan ordering as was shown in the 30-year study, which is summarized below.

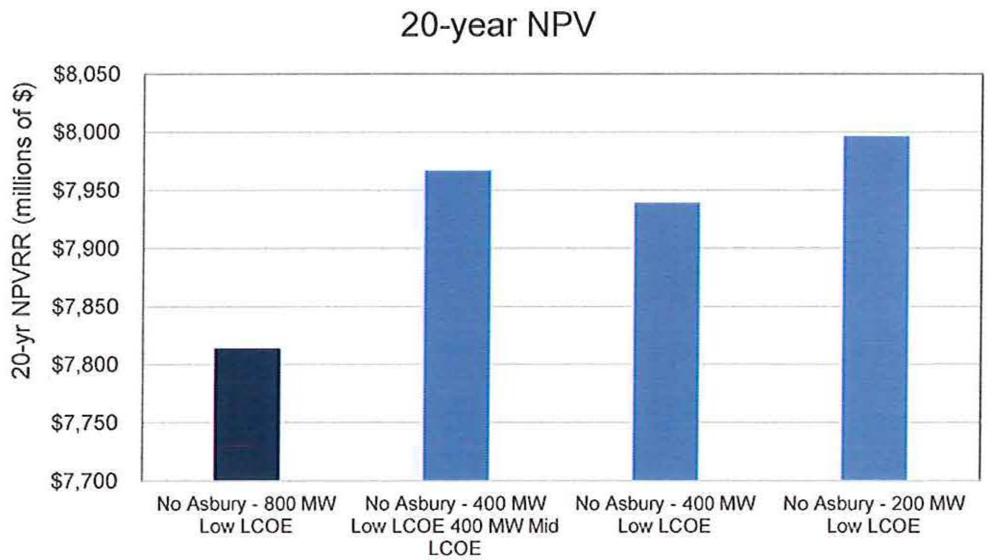


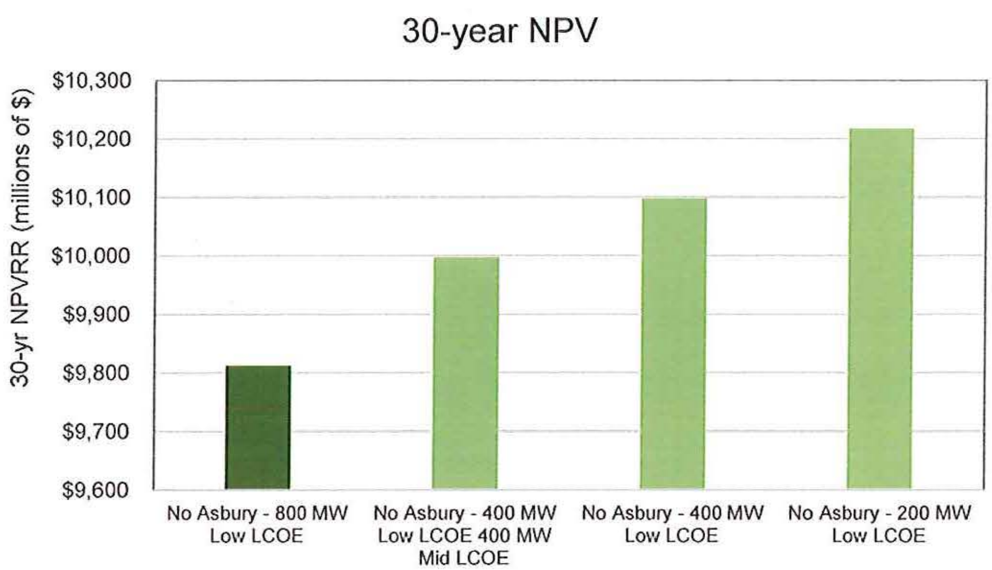
- *Additional Plans with Different DSM Assumptions* – Updated DSM plans were developed and evaluated against Plan 2 from the GFSA. Plan 2 from the GFSA included RAP DSM. The new plans were developed with No DSM, RAP-, RAP+ and MAP. In all four alternate DSM plans, 800 MW of Low-LCOE wind was still built, as in Plan 2 (the Base Plan). The new plans resulted in slight changes in new build timing. Adding more DSM increased the relative cost of Plan 2 by up to $58M on a 20-year NPV basis (vs. MAP). Removing DSM decreased the relative cost of Plan 2 by up to $43M on a 20-year NPV basis (No DSM). These results are shown below, with the relationship the same on the 30-year NPV basis.



- *Additional Plans with New Constraints* – The plans with additional constraints either adjusted Plan 2 (800 MW of low-LCOE wind) or Plan 4 (keep Asbury with 800 MW of low-LCOE wind).

- Additional wind constraints were placed on Plan 2 from the GFSA, to limit the new wind quantities to 400 MW and 200 MW versus the original 800 MW built in Plan 2 in the GFSA.
    - The plan with a 400MW limit resulted in an incremental cost of $167M over 20 years
    - The plan with a 200MW limit resulted in an incremental cost of $243M over 20 years
- Wind constraints were also placed on Plan 4, limiting the amount of Low-LCOE wind to 400 MW, limiting Low-LCOE wind to 400 MW and Mid-LCOE wind to 0 MW, and limiting Low-LCOE wind to 200 MW and Mid-LCOE wind to 0 MW.
    - The plan with a 400 MW limit on Low-LCOE wind resulted in an incremental cost of $153M on a 20-year basis and $186M on a 30-year basis
    - The plan with a 400 MW limit on Low-LCOE wind and 0 MW limit on Mid-LCOE wind resulted in an incremental cost of $125M on a 20-year basis and $287M on a 30-year basis
    - The plan with a 200 MW limit on Low-LCOE wind and 0 MW limit on Mid-LCOE wind resulted in an incremental cost of $182M on a 20-year basis and $406M on a 30-year basis
    - It should be noted that the relative cost impacts varied across plans for the 20-year and 30-year time horizon, as the performance of mid-LCOE improves over time as market prices are expected to increase. This is shown below.





- Other constraints placed on Plan 4 included delaying the Energy Center retirement, replacing the 167 MW reciprocating engine with a gas CT, and replacing the 167 MW reciprocating engine with a gas CT as well as removing the solar builds.
  - The plan that delays the retirement of Energy Center reduces costs by $4 million on both a 20-year and 30-year NPV basis.
  - The plan that replaces the reciprocating engine with a CT increases costs by $11 million (20-year NPV) and $36 million (30-year NPV).

- The plan that replaces the reciprocating engine with a CT *and* removes solar increases costs by $5 million (20-year NPV) and $48 million (30-year NPV).

- *Alternative Assumption with Corporate Tax Change* – The nine original plans were evaluated with revised assumptions regarding the corporate tax rate, as per the federal tax reform legislation passed in December, 2017. ***The results from this modeling run will be available in a supplemental response.***
- *Alternative Assumption with load uncertainty* – The nine original plans were evaluated against an additional critical uncertain factor for Empire load growth. This expanded the stochastic analysis from 18 endpoints to 54 endpoints. The high load growth case assumed the 2016 IRP high load case, while the low load growth case assumed the 2016 IRP low load case, less 3.5% to adjust for demand side reductions less an assumed amount of new community solar. ***The results from this modeling run will be available in a supplemental response.***

Updated Plan 4

A new plan, labeled 4b in the accompanying spreadsheet, was added to the portfolio to reflect a correction to Plan 4. Plan 4 erroneously included approximately $65 million of additional annual costs associated with a reciprocating engine generation resource after it was added in 2035. The impact of this change is a PVRR that is $49 million lower than Plan 4 on a 20-year basis. This change has not impacted the forecasted economics of the wind additions contained in the plans.

Plan 4b performs relatively better over the long-term versus Plan 2 after the reciprocating engine accounting correction because of the rising gas prices in the base case. Plan 2 builds 200 MW of combined cycle capacity in the mid-2020s that Plan 4b does not build, as a result of Asbury remaining in service. Plan 4b instead builds 200 MW of solar in the early 2030s and 167 MW of reciprocating engine capacity in 2035. As gas prices rise, the solar units perform relatively better than the combined cycles, improving Plan 4b's relative performance over time.

Across the stochastic analysis, Plan 2 results in lower costs than Plan 4b across most of the 18 endpoints. This is because it performs better most of the time when CO2 prices are in place and when market prices are low. Thus, Plan 2 provides risk mitigation against a potential market outcome with more sustained low gas prices and with a carbon price. ***An updated stochastic case will be provided early next week illustrating how the risks of fuel and a carbon price, in particular, change with the updated Plan assumptions.***

The Empire District Electric Company
Missouri Public Service Commission
Case No. EO-2018-0092
Response to Staff's Sixth Set of Data Requests

Response provided by: Todd Mooney

Title: Vice President, Finance & Administration

Company Response Number: STAFF 6-29

Date of Response: January 25, 2018

Question:

At page 17 of Todd Mooney's Direct Testimony, lines 10-11, he refers to Liberty Power having developed and financed 750 MWs of wind projects. 1) Please identify the specific projects he is referring to and the nature of the ownership interest APUC and/or Liberty Power may presently have in each of these wind projects. 2) Please identify the entity that is presently operating each of these projects and whether it is unregulated merchant generation or regulated public utility generation.

Response:

The table below summarizes the wind projects in the United States that have been financed by Liberty Power through a tax equity partnership arrangement.

<table>
<tr><th>Facility</th><th>APUC Subsidiary Ownership Interest</th><th>Overall Cost of Facility ($M USD)</th><th>Tax Equity Investment ($M USD and %)</th><th>State</th><th>Start of Commercial Operations</th><th>Entity Operating Facility</th><th>O&M Contract</th><th>Regulated vs. Unregulated</th></tr>
<tr><td>Deerfield 150 MW</td><td>100% Class B Shares</td><td>$ 303</td><td>$ 164 54%</td><td>MI</td><td>Feb-17</td><td>Deerfield Wind Energy, LLC</td><td>Yes With Vestas</td><td>Unregulated</td></tr>
<tr><td>Odell 200 MW</td><td>100% Class B Shares</td><td>$ 331</td><td>$ 180 54%</td><td>MN</td><td>Aug-16</td><td>Odell Wind Farm, LLC</td><td>Yes with Vestas</td><td>Unregulated</td></tr>
<tr><td>Minonk 200 MW</td><td rowspan="3">100% Class B Shares</td><td rowspan="3">$ 754</td><td rowspan="3">$ 297 39%</td><td>IL</td><td>Dec-12</td><td>Minonk Wind, LLC</td><td>Yes with Gamesa</td><td>Unregulated</td></tr>
<tr><td>Sandy Ridge 50 MW</td><td>PA</td><td>Jul-12</td><td>Sandy Ridge Wind, LLC</td><td>Yes with Gamesa</td><td>Unregulated</td></tr>
<tr><td>Senate 150 MW</td><td>TX</td><td>Dec-12</td><td>Senate Wind, LLC</td><td>Yes with Gamesa</td><td>Unregulated</td></tr>
</table>

Responsible person(s): Todd Mooney

Schedule JAR-r4

The Empire District Electric Company
Missouri Public Service Commission
Case No. EO-2018-0092
Response to Staff's Eleventh Set of Data Requests

Response provided by:	Todd Mooney
Title:	Vice President, Finance & Administration
Company Response Number:	STAFF 11-38
Date of Response:	January 30, 2018

Question:
Did Algonquin Power & Utilities Corporation (APUC) or any APUC subsidiary apply for approval of wind project financing by any regulated public utility prior to entering into tax equity partnership arrangements for the following APUC unregulated merchant generator facilities: 1) Deerfield 150 MW wind project in Michigan, 2) Odell 200 MW wind project in Minnesota, 3) Minonk 200 MW wind project in Illinois, 4) Sandy Ridge 50 MW wind project in Pennsylvania, or 5) Senate 150 MW wind project in Texas? If so, please provide a detailed discussion for each such wind project, including any relevant state regulatory commission docket numbers.

Response:
The Deerfield, Odell, Minonk, Sandy Ridge and Senate projects did not involve a public utility and thus no state regulatory approvals were required. Each of these projects obtained Market Based Rate Authority from the Federal Energy Regulatory Commission.

Responsible person(s): Todd Mooney