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REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

ON BEHALF OF

SHOW-ME CONCERNED LAND OWNERS

September 15, 2014

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Q. WHAT IS YOUR NAME, PRESENT POSITION AND ADDRESS?

A. My name is Michael S. Proctor. I am currently an independent consultant. My home address is 2172 Butterfield Drive, Maryland Heights, MO., 63043

Q. ON BEHALF OF WHAT PARTY TO THIS CASE ARE YOU TESTIFYING?

A. I am testifying on behalf of Show-Me Concerned Land Owners.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. I received a PhD in economics from Texas A&M University. I taught economics and management science at Purdue University and the University of Missouri. In 1977 I joined the staff of the Missouri Public Service Commission (Missouri Commission) where I was the Chief Economist. After retiring in 2009 I have consulted on a variety of issues related to transmission planning, cost allocation and markets for Regional Transmission Organizations. I currently have a consulting contract with the Regional State Committee (RSC) of the Southwest Power Pool (SPP). My curriculum vita is provided in **Schedule MSP-1** attached to my rebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will address the direst testimonies submitted on behalf of Grain Belt Express Clean Line by Mr. David Berry and Mr. Gary Moland. I have reviewed these testimonies, submitted data requests and reviewed appropriate work products of these witnesses. My rebuttal testimony will address issues I found with their analysis. An Executive Summary of my rebuttal testimony is found in Schedule MSP-2 attached to my rebuttal testimony.

I. REBUTTAL OF THE DIRECT TESTIMONY OF DAVID BERRY

A. OVERVIEW

Q. WHAT PORTIONS OF DAVID BERRY'S DIRECT TESTIMONY ARE YOU ADDRESSING?

A. The focus of my rebuttal testimony is on the Levelized Cost Analysis presented in Mr. Berry's direct testimony.

Q. WHAT IS A LEVELIZED COST ANALYSIS?

A. In regulated utility analysis, levelized costs represent the per-year revenue requirement to cover the return of and on investment as well as annual expenses over the life of the asset. Levelized cost is calculated by finding a constant year-to-year revenue requirement that has the same net present value as the actual year-to-year revenue requirements that decrease over time as net investment decreases.

Q. WHAT IS THE PURPOSE OF A LEVELIZED COST ANALYSIS?

A. Generally, the purpose of a levelized cost analysis is to provide a way to compare investment alternatives that have differing investment costs, expenses and asset lives.

Q. DO YOU AGREE WITH MR. BERRY THAT A LEVELIZED COST ANALYSIS IS APPROPROIATE FOR SHOWING THE ECONOMIC FEASIBILITY OF THE GRAIN BELT DC TRANSMISSION PROJECT?

A. Levelized cost analysis is an appropriate method to use in comparing resources that run at 100% of their capability; i.e., whose available generation is always dispatched. These are sometimes called based-loaded generation resources. The following table is an example of such a comparison for national average data from the Energy Information Agency (EIA) of the Department of Energy (DOE).

U. S. Average Levelized Cost (2011 $MWh for Plants Entering Service in 2018
(Source: EIA: Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013)

Project Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M + Fuel	Transmission Investment	Total Levelized Cost
Convential Coal	85%	$65.70	$4.10	$29.20	$1.20	$100.20
Covential Combined Cycle	87%	$15.80	$1.70	$48.40	$1.20	$67.10
Wind	34%	$70.30	$13.10	$0.00	$3.20	$86.60

In the above table, the capacity factors represent the percent of time each project type is operating at 100% of their installed capacity. For conventional generation, the less than 100% represents the time units are forced out or are down for maintenance. For wind, the lower percentage represents the average availability of wind. The cited report notes that if a utility needs dispatchable generation, then levelized cost analysis is only used to eliminate generation alternatives that have higher costs across all levels of dispatchability. Once potentially economic generation alternatives are determined, least-cost generation resource combinations are determined using generation expansion models that evaluate energy production, energy costs and capacity costs of various alternatives over multiple years.

Q. WOULD IT BE CORRECT TO SAY THAT MR. BERRY'S USED LEVELIZED COST AS A SCREENING TOOL TO DETERMINE WHICH BASE-LOADED RESOURCES ARE MOST ECONOMIC?

A. Yes. Since the transmission cost of the Grain Belt DC transmission (DC Transmission) project is so high (estimated by Mr. Berry to be $15-$20 per MWh compared to just over $3/MWh for wind in the previous table), an analysis needs to be provided that shows the generation and transmission services from the wind farms in western Kansas are less costly than other base-loaded generation projects not requiring the same high cost transmission to deliver the power into the Ameren Missouri service area. Specifically, do the savings from the higher capacity factor of the western Kansas wind make up for the added cost for transmission? The remainder of my rebuttal testimony of Mr. Berry will look in-depth at his calculation of levelized costs for various resources, and correct those calculations where errors were made.

B. PRELIMINALY OBSERVATIONS ON MR. BERRY'S LEVELIZED COST ANALYSIS

Q. WHAT OVERALL ISSUE DID YOU FIND WITH MR. BERRY'S LEVELIZED COST ANALYSIS?

A. Mr. Berry did not perform his levelized cost analysis in the same way as is typically done for regulated utilities. Instead of calculating revenue requirements for a regulated utility that includes a return of and on total capital investment, Mr. Berry calculates the investment cost minus the net present value of tax depreciation. Mr. Berry also includes a value for the potential sale of capacity from the capital investment. The result is what Mr. Berry calls the "levelized cost of energy." Mr. Berry used the cost of a combustion turbine as the value of capacity. Even though Mr. Berry presents results with and without the added capacity value in graphical form on page 18 of his testimony, the calculations without capacity value do not reflect what regulated utilities would call levelized cost.

Q. WHAT IS METHOD USED BY REGULATED UTILITIES TO CALCULATE LEVELIZED COSTS?

A. The following table sets out the components for calculating the annual revenue requirements for a generation asset owned by a regulated utility. Net Investment is Gross Investment (Capital Cost of the asset) minus accumulated Straight- Line (S-L) Depreciation, and Tax Depreciation is typically accelerated compared to S-L Depreciation. The first five components comprise what are called "Capacity Costs," that include the return of and on investment as well as taxes related to the investment; i.e., income tax and property tax. The final two components are annual expenses. The annual revenue requirements include all costs that would be collected in rates from the utility's customers.

Return on Equity	(Equity Rate)*(Equity %)*(Net Investment)
Income Tax	(Tax Rate)*(Return on Equity – Tax Depreciation)
Interest on Debt	(Interest Rate)*(Net Investment)
Return of Investment	Straight-Line Depreciation = (Capital Cost/Asset Life)
Property Tax	(Tax Rate)*(% Assessment)*(Net Investment)
O&M Expense	Fixed O&M + Variable O&M
Fuel Expense	(Fuel Cost [($/MMBtu)*(MMBtu/MWh)]*(MWh)

Each year of revenue requirements is discounted to obtain the NPV of the annual revenue requirements over the asset life. The NPV of the revenue requirements are then divided by the sum of the annual discount factors to obtain a "levelized" (same dollar amount each year) revenue requirement, whose net present value (NPV) is equal to the NPV previously calculated on the non- levelized revenue requirements. To convert this levelized revenue requirement from dollars to $/MWh, the levelized revenue requirement is divided by the average annual MWh generation expected from the generation asset.

Q. WHAT OTHER ISSUES DO YOU HAVE WITH MR. BERRY'S CALCUATION OF "LEVELIZED ENERGY COST?"

A. Mr. Berry's calculation of what he calls the "capitalization factor" is incorrect. In Mr. Berry's calculations the assumed date of commercial operation is 2019 for all alternatives. Mr. Berry includes the Capacity Costs in 2018, and then takes the NPV of all components back to 2018. But when he calculates the capitalization factor he does not include the discount factor for 2018 when adding the discount factors over the life of the asset. The result is his capitalization factor is equal to the correct capitalization factor discounted back one year. Thus, his levelized costs are calculated by dividing by a capitalization factor that is too low, resulting in too high of a levelized cost.

Also, Mr. Berry confuses inflation rates with cost escalation over the asset life. This results in an overestimate of the annual O&M costs for most of the alternatives. In the case of wind, Mr. Berry combines the inflation rate with an escalation rate. I will discuss this case further in the next section of my rebuttal testimony.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. BERRY'S CALCULATIONS OF "LEVELIZED ENERGY COSTS?"

A. His method of calculation does not conform to utility practice and therefore does not properly represent the cost that a regulated utility would have to pay. The Missouri Commission should treat Mr. Berry's estimates as inadequate for making a determination as to the economic viability of the DC Transmission project. In the remainder of my rebuttal to Mr. Berry I will provide levelized cost estimates that do conform to utility practice and do reflect the costs that a regulated utility would have to pay.

C. LEVELIZED COST FOR KANSAS WIND GENERATION

1. LEVELIZED CAPACITY COSTS

Q. WHAT DOES MR. BERRY ESTIMATE AS THE LEVELIZED COST FOR THE ENERGY FROM THE KANSAS WIND FARMS TO BE LOCATED AT THE SOURCE OF THE DC TRANSMISSION PROJECT?

A. According to Mr. Berry's worksheets which he provided to me, he estimated the levelized cost to be $15/MWh.

Q. DID THIS ESTIMATE APPEAR TO BE REASONABLE?

A. At first, it did not. As a consultant for the SPP RSC I monitor the meetings of the Economic Studies Working Group (ESWG) that is responsible for the economic inputs that go into the SPP's Integrated Transmission Planning. As a part of that planning process, SPP must estimate what generation is most likely to be built to meet needs 10 and 20 years out. The basic generation alternatives considered are: nuclear; coal; combined cycle; combustion turbine, and wind. In the SPP analysis the lowest and most recent levelized cost for wind generation has been \$35/MWh, not including annual O&M expense. This is in agreement with the latest price data reported in US Department of Energy's 2012 Wind Technologies Market Report (DOE 2012 WTMR) at page 35, where the average levelized Purchase Power Agreement prices for the interior region in 2011 and 2012 is above \$30/MWh, and none of the prices are below \$20/MWh.

Q. BY ANALYZING MR. BERRY'S WORK PAPERS HAVE YOU BEEN ABLE TO DISCOVER THE REASONS THAT HIS ESTIMATES FOR LEVELIZED COST FOR KANSAS WIND WERE SO LOW?

A. Yes, I have. I looked at three major areas: 1) Implicit Capacity Costs); 2) Annual Expenses; and 3) Credits used to offset costs. The following table summarizes my findings.

Berry's Calculations for Kansas Wind

Revenue Requirements	**\$/MWh**
Implicit Capacity Cost	\$38.57
Expenses	\$11.90
Total Revenue Requirement	**\$50.47**

Credits	**\$/MWh**
Capacity Revenues	\$7.89
Production Tax Credits	\$27.49
Berry's LCOE (\$/MWh)	**\$15.08**

While I found many issues with Mr. Berry's calculations of implicit capacity costs as well as for annual expenses, I discovered that the primary reason for his low levelized cost for Kansas wind comes from the credits he used to offset costs. These levelized costs do not include the costs of the DC Transmission project, nor do they take into account losses on that line.

Q. WHAT DO YOU MEAN BY CAPACITY COSTS?

A. For Kansas Wind capacity costs include the return of and on investment along with income taxes, or sometimes called "pre-tax" return on investment.[1] Levelized cost analysis calculates the return of investment using annual, straight-line depreciation. The return on investment is what is required to cover the annual interest expense as well as annual rate of return on equity including income taxes. Using the DOE 2012 WTMR's interior region's average installed cost for a wind turbine of $1.760/kW-yr (at page 36) and Mr. Berry's rates for return on investment, interest, discount and income taxes, I estimated the levelized capacity costs for Kansas Wind to be $34.63/MWh, which is essentially the same cost as those used by the SPP. Notice that the EIA estimate of $70.30/MWh (in previous table on page 2) is based on an assumed 34% capacity factor. Adjusting the capacity factor to 50% reduces the EIA estimate to $47.80/MWh. A major reason for EIA's higher levelized cost is the higher project cost per kW-year at the time of the 2013 EIA report.

Q. HOW DOES THIS LEVELIZED COST FOR THE RETURN OF AND ON INVESTMENT COMPARE TO MR. BERRY'S CALCULATIONS?

A. Subtracting out his levelized costs for revenue credits and expenses, Mr. Berry's residual for what would be implicit capacity costs is $38.57/MWh. Even though Mr. Berry's estimate is higher than mine, in Mr. Berry's work papers I found that he had used $1,750/kW-yr and had

[1] Some analysts include property taxes as capacity costs. For Kansas wind, there are no property taxes.

deflated the estimated cost one year, lowering the investment cost to $1,707/kW-yr. In addition Mr. Berry used a wind capacity factor of 55%, which he considered mid-range, even though his survey of potential suppliers averaged 52% and the DOE 2012 WTMR on Figure 31 at page 48 shows the highest 2012 capacity factor in the interior region to be 50%. I used a wind capacity factor of 50%, which is representative of a mid-to-high range estimate for the western Kansas region. A mid-range capacity factor for Kansas Wind would be lower than the 50% level used in my analysis; perhaps as low as 45%. These capacity factors are measured at the generators, not at the delivery point. Thus, losses need to be taken into account. Mr. Berry's calculation of $38.57/MWh does not include transmission losses.

Q. WHAT ROLE DOES THE CAPACITY FACTOR PLAY IN THE CALCULATION OF A LEVELIZED COST FOR A RESOURCE?

A. Levelized cost is simply a constant per year revenue requirement whose present value is equal to the present value of estimated revenue requirements over the life of an asset. In order to convert this dollar value to dollars per MWh, the levelized cost is divided by the MWh expected to be produced by the generation asset each year. In the case of wind, the capacity factor is equal to the expected MWh produced in a typical year divided by the maximum MWh that could be produced if the wind was generating at the full capacity of the plant every hour of the year.

Levelized costs can easily be calculated on a 1 MW basis. Since the capacity factor times 8,760 hours is the MWh produced by a generator having 1 MW of capacity, levelized cost can be divided by the capacity factor times 8,760 hours to convert to $/MWh. If two alternatives have the same levelized costs in dollars (for example two wind farms), the alternative having the higher capacity factor (for example more consistent wind compared to less consistent wind) will have the lower levelized cost per MWh.

2. LEVELIZED EXPENSES

Q. WHAT DID MR. BERRY INCLUDE IN ANNUAL EXPENSE FOR KANSAS WIND?

A. There is no property tax and no fuel expense for Kansas wind. Mr. Berry used an estimate of $7.50/MWh which he determined from the 2012 Wind Technologies Market Report. To this Mr. Berry added a 2.5% inflation factor to arrive at a starting 2019 value of $8.70/MWh. He then adds to the 2.5% inflation factor plus a 1% escalation factor for a 3.5% year-to-year increase. Based on these assumptions, Mr. Berry estimates a levelized expense of $11.90/MWh.

Q. DO YOU AGREE WITH MR. BERRY'S APPROACH FOR ESTIMATING ANNUAL EXPENSE FOR KANSAS WIND?

A. No, I do not. I do not agree with the use of an inflation factor and the combination of an inflation factor and escalation factor to arrive at nominal cost for annual expense.

Q. WHY IS IT INCORRECT TO USE INFLATION FACTORS TO INCREASE YEAR-TO YEAR COSTS OVER THE LIFE OF AN ASSET IN THE CALCULATION OF LEVELIZED COSTS?

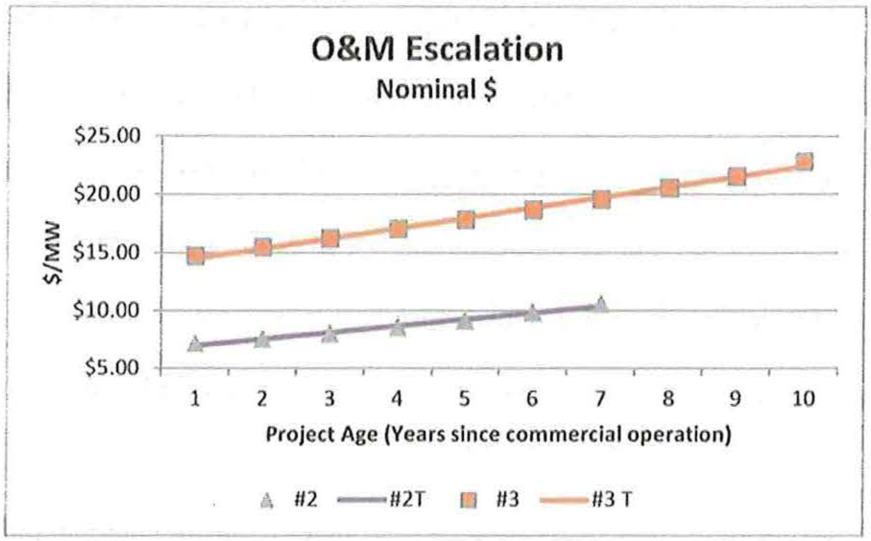
A. An inflation factor is used to account for the purchasing power of a dollar in the purchase of a bundle of goods. For example the Consumer Price Index (CPI) is used for calculating the purchasing power of retail customers and the Wholesale Price Index (WPI) is used for calculating the purchasing power of wholesale customers. The Gross Domestic Product (GDP) price index is typically used in studies by the Energy Information Agency (EIA) that produces energy forecasts for the Department of Energy. No matter which price index is used, the inflation rate from year x to year y is calculated as the index in year y divided by the index in year x. Forecast of costs are typically done in nominal dollars – the actual costs at the time the expenditure is made. In order to convert these forecasts to real dollars in year x, the nominal dollars in year y are divided by the inflation factor from year x to year y. The result is a forecast based on the purchasing power in year x.

The data reported in the DOE 2012 WTMR on median annual O&M costs for wind generation is stated to be in 2012 $/MWh. This means that the data reported before 2012 was factored up for inflation from the date the data was reported to the year 2012 using a price index. The data was then separated into three groups (1998-2004; 2005-2008 & 2009-2011) depending on the date of commercial operation. For each of the three groups, median (middle) $/MWh of expense were calculated for each of the years since the wind farm's commercial operation date. The data was then analyzed for upward trends over the years since commercial operation.

Apparently, Mr. Berry believed that to convert these trends to nominal dollar he should apply a forecasted inflation rate for each subsequent year, but this is not the correct way to get from real dollars to nominal dollars. Instead, the real dollar data should first be converted back to nominal dollars and then the trends analyzed to determine if the data shows an escalation of costs in nominal dollars.

Q. DID YOU ANALYZE THE DATA FOR COST ESCALATION IN NOMINAL DOLLARS?

A. Yes, I did. The data had been sorted into three groups according to year of commercial operation: 1) 2009-2011; 2) 2005-2008; and 3) 1996-2004. I used the GDP price index to convert the data from real to nominal values, and then performed a linear trend analysis for each group. Group 1 only has three observations, and is likely to be of little value in determining trends. The first three observations from Group 2 showed slightly lower costs, but were in the same range as Group 1. Group 3 (the older wind generators) showed significantly higher costs than either Group 1 or 2, and also showed a higher level of cost escalation. The following graph shows the trend results for Groups 2 and 3.



Notice that both groups fit a dollar per year escalation very well. However, since Group 2 tracks better with the more recent data, having a lower dollar level and a lower dollar per year escalation, I used the trend line values from Group 2 as the best estimate for the most recently built wind farms.

Q. DID YOU PERFORM A SIMILAR ANALYSIS USING 2012 REAL DATA?

A. Yes, I did. As shown in the following graph, the trend lines for the real data do not provide as good a fit as the trend lines for the nominal data. However, after calculating the trends for real, I compared them to the trends for the nominal.

The real data shows a higher level of escalation than the nominal data. The following table compares the trend lines for real vs. nominal for Groups 2 and 3.

Trends	Group 2		Group 3	
	Real	Nominal	Real	Nominal
Year 1	$6.25	$7.00	$11.35	$14.53
Year 25	$23.39	$20.65	$36.81	$35.68
Yr to Yr Inc	$0.71	$0.57	$1.06	$0.88
Avg Growth Rate	5.65%	4.61%	5.02%	3.82%

Notice the lower starting values at year 1 for the real trends, but the higher ending values at year 25, resulting in a higher year-to-year increase as well as a higher average 25 year escalation rate for the real data compared to the nominal data.

Q. USING THE TREND LINE FOR NOMINAL COSTS FROM GROUP 2, WHAT ESTIMATE OF LEVELIZED O&M COST DID YOU CALCULATE FOR WIND?

A. Using the trend line for nominal O&M expenses I calculated a levelized O&M expense estimate over the 25 year life of $11.73/MWh. While we differed in approach, this estimate is comparable to Mr. Berry's estimate of $11.90/MWh.

Q. TO THIS POINT IN THE ANALYSIS WHAT IS YOUR ESTIMATE OF LEVELIZED WIND COSTS COMPARED TO MR. BERRY?

A. I estimate the levelized cost of Kansas wind to be \$46.35/MWh, and Mr. Berry estimates the levelized costs to be \$50.47/MWh. In order for Mr. Berry's final estimate to be \$15/MWh, he must show \$35/MWh in credits to offset these costs.

3. REVENUE REQUIREMENT CREDITS VS CHARGES FOR KANSAS WIND

Q. WHAT CREDITS DID MR. BERRY INCLUDE IN HIS LEVELIZED COST ANALYSIS?

A. Mr. Berry included a Production Tax Credit and a Capacity Credit for the accredited capacity for resource adequacy (MW available at times of summer peak) of the Kansas Wind Farms.

Q. WHAT IS A PRODUCTION TAX CREDIT?

A. The federal government allows a \$23/MWh tax credit for MWh produced over the first 10 years of operations for wind farms that began construction prior to December 31, 2013.

Q. WHAT DID MR. BERRY ESTIMATE THE LEVELIZED LEVEL TO BE FOR THE PRODUCTION TAX CREDIT?

A. Mr. Berry estimated a levelized production tax credit of \$27.49/MWh over the first 10 years of the 25 year life of the Kansas wind farms. Mr. Berry applied the inflation rate as if the federal law would grant wind farms an inflation factor of 2.5% per year to the production tax credit.

Q. WHAT IS YOUR ESTIMATE OF THE PRODUCTION TAX CREDIT?

A. I used the EIA inflation factor of 1.55% to arrive at \$25/MWh as nominal dollars in 2019, and using the EIA inflation factor of 1.65% over the next ten years, estimated the levelized production tax credit to be \$16.51/MWh. Along with the availability of production tax credits for renewable energy, the future rate of inflation is a major uncertainty in calculating the production tax credit.

Q. DO YOU AGREE THAT THE PRODUCTION TAX CREDIT FOR RENEWABLE ENERGY WILL APPLY TO THE KANSAS WIND FARMS THAT CONNECT TO THE DC TRANSMISSION PROJECT IN 2019?

A. No, I do not. It is impossible to know what congress will enact in the future with respect to renewable energy. To meet current law, these farms would have had to have started construction prior to December 31 of last year. In order for this to make sense, these farms will have to interconnect to the SPP transmission system in order to generate revenues to cover their investment until 2019. These interconnection costs are not insignificant (in the order of $300/kW). I would estimate that wind farms already interconnected to SPP would not be willing to switch interconnections to the DC Transmission project, so that essentially the wind farms interconnecting to the DC Transmission project would primarily be those constructed just prior to 2019 and would not be eligible for the existing production tax credit.

Congress has yet to extend the production tax credits for wind in the 2014 session. The last extension in 2013 simply changed the existing requirement from "fully operational" to "under construction" by December 31, 2013. Thus, it would not seem reasonable to assume production tax credits will be extended past what is allowed by current legislation.

Q. WHAT CAPACITY CREDIT WAS CALCULATED BY MR. BERRY?

A. Mr. Berry assumed accredited capacity equal to 17.05% of name plate capacity for Kansas wind, and valued this capacity at the cost of a combustion turbine at $957/kw. As with variable O&M and production tax credits, Mr. Berry not only inflated the cost of the combustion turbine to 2019 dollar, but used the inflation rate as an escalation rate over the 25 year life of the wind farm. This resulted in a levelized capacity credit of $7.89/MWh.

When Mr. Berry's levelized production tax credit and capacity credit are added, the result is a total credit against cost of $35.39/MWh. When this is subtracted from his levelized cost estimate of $50.47/MWh, the result is a levelized cost for Kansas wind of $15.08/MWh

Q. DO YOU AGREE WITH MR. BERRY'S CAPACITY CREDIT?

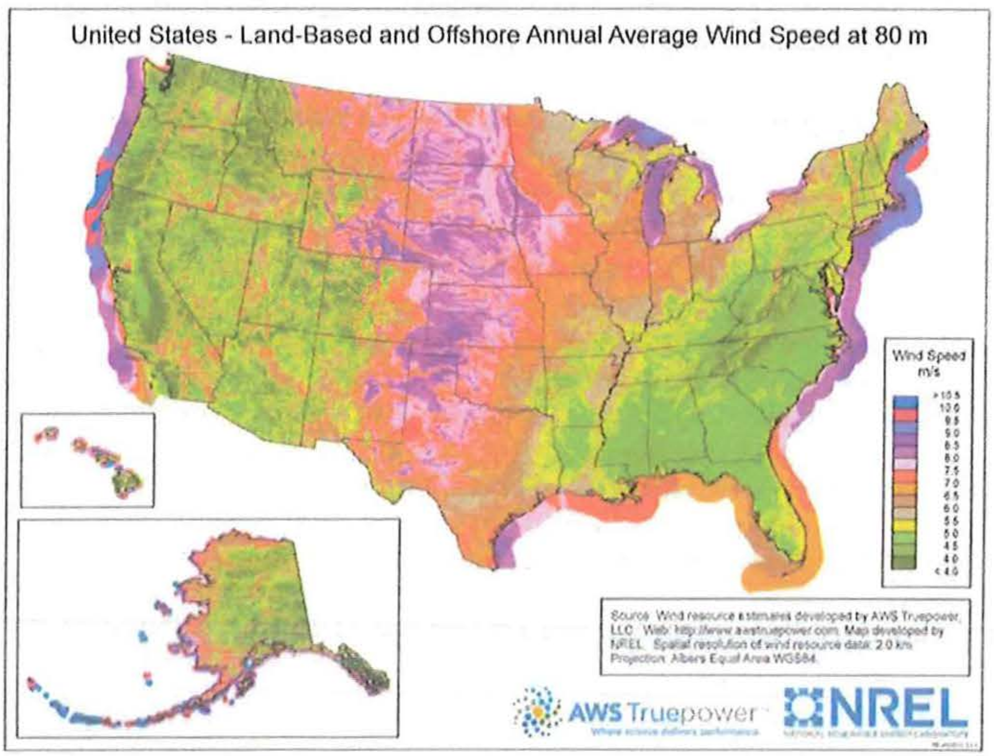
A. No, I do not. In addition to this not being included in a standard calculation of levelized costs, because of the risk involved in being able to sell the capacity in a capacity market subtracting capacity credits is not the way a wind farm would sell energy. Similarly, if a utility were considering purchasing a wind farm in Kansas, subtracting the capacity value is not the treatment that it would use in making a decision. In addition, Mr. Berry estimate of 17.05% accredited (unforced) capacity available during the summer peak period was not calculated using any known standard for determining accredited capacity.

Q. WHAT IS THE STANDARD WAY ACCREDITED CAPACITY DIFFERENCE BETWEEN WIND FARMS AND NON-RENEWABLE GENERATION IS TAKEN INTO ACCOUNT?

A. To compare two generation resources, the accredited capacity of the resource with the lower percentage of accredited capacity is subtracted from the resource with the higher percentage of accredited capacity. For example, a combined cycle plant with accredited (unforced) capacity of 93% and Kansas wind having accredited (unforced) capacity of 14.5% would result in a difference of 78.5% in accredited capacity. In order to compare the costs of these two resources, the cost of additional 78.5% of accredited capacity would need to be added to the cost of the Kansas wind. Including the capital and fixed O&M costs for a combustion turbine, I estimate this added capacity cost to be $19.30/MWh. Adding this to the cost of Kansas Wind before production tax credits gives a total levelized cost of $65.65/MWh.

Q. WHY DID YOU USE 14.5% ACCREDITED CAPACITY FOR KANSAS WIND INSTEAD OF 17.05% USED BY MR. BERRY?

A. Mr. Berry calculated the 17.05% by multiplying the Midwest ISO's accredited capacity for Missouri Wind of 9.3% by ratio of Kansas wind capacity factor of 55% to the Missouri wind capacity factor of 30%. In order for this calculation to be valid, this ratio of 1.83 would have to apply during the peak hours of the summer when accredited capacity is determined. The problem is that during the hot peak hours, wind tends to reduce significantly in both high and low wind areas, but not in proportion to the average of wind production throughout the year. The following map shows wind speeds in the United States.



I used 14.5% because it is the average of the highest capacity factor region in the Dakotas and western Minnesota (15.8%) with the Iowa region (13.7%) in the Midwest ISO. I chose these two regions because the highest capacity factor region is in the northwest portion of the Midwest ISO, has similar average annual wind speeds, but lower summer temperatures than western Kansas. The wind in northwest Iowa also has the same annual average wind speeds as western Kansas. It should also be noted that these accredited capacity values for the summer peak were measured by the Midwest ISO in 2012 which had the highest accredited capacity values over the last three years. Even in this case, these accredited capacities for wind did not reach 17%.

4. <u>TRANSMISSION COSTS AND LOSSES FOR KANSAS WIND</u>

Q. WHAT OTHER FACTORS NEED TO BE TAKEN INTO ACCOUNT REGARDING THE LEVELIZED COST OF WESTERN KANSAS WIND VIA THE DC TRANSMISSION PROJECT?

A. Transmission costs and transmission losses need to be taken into account. The reason for this is that a proper comparison of western Kansas wind generation to other generation resources that can locate in Ameren Missouri's service territory require the wind energy from Kansas to be delivered to the Ameren Missouri service territory. This requires the inclusion of the transmission costs and losses needed to deliver the wind generation to Ameren Missouri's service territory, but does not include transmission costs and losses to deliver from generation located in Ameren Missouri's service territory to Ameren Missouri's load, as these costs would be similar for all resource alternatives being considered.

Q. WHAT ARE THE TRANSMISSION COSTS FOR THE DC TRANSMISSION PROJECT?

A. In his direct testimony, Mr. Berry estimates these costs to be in the range of $15/MWh to $20/MWh. In his worksheet, Mr. Berry calculates a levelized cost for the DC Transmission project to be $18.47/MWh. Since these are preliminary estimates, they are likely to be low. The SPP has found preliminary cost estimates for transmission projects to be 30% lower than actual costs. This might be included in Mr. Berry's range (i.e., \$20/MWh = 1.33 * \$15/MWh).

However using Mr. Berry's rate calculation for the DC Transmission project of \$89.07/kW-yr results in a levelized cost of \$17/MWh, and adding 30% results in a levelized cost of \$22/MWh. This estimate is slightly higher than the high end of Mr. Berry's estimate range because I am using a capacity factor of 50% instead of the 55% that he used. The same result can be obtained by multiplying Mr. Berry's estimated range by the ratio of 0.55/0.5 = 1.1; i.e., a 10% increase in cost due to a lower capacity factor would change \$20/MWh to \$22/MWh. I believe \$22/MWh is a reasonable estimate to use. Adding \$22/MWh for transmission to \$65.65/MWh for generation, results in a levelized cost for Kansas Wind of \$87.65/MWh.

Q. WHAT ARE THE TRANSMISSION LOSSES FOR THE GRAIN BELT DC TRANSMISSION PROJECT?

A. Mr. Berry estimates these to be 5%. Thus, actual delivered energy is 5% lower than generated energy. This means that all cost estimates need to be divided by 0.95 to accurately reflect the cost of delivered energy. Accounting for losses adds \$4.61/MWh, bringing the total cost for western Kansas Wind delivered into Ameren Missouri's service territory to \$92.26/MWh.

D. LEVELIZED COST OF COMBINED-CYCLE GENERATION

1. DIFFERENCE IN LEVELIZED COST

Q. DID MR. BERRY CALCULATE THE LEVELIZED COST FOR A COMBINED CYCLE GENERATION ALTERNATIVE?

A. Yes, he provided those calculations in his work papers.

Q. DID YOU FIND THE SAME OVERALL PROBLEMS WITH MR. BERRY'S METHOD OF CALCULATING LEVELIZED COSTS FOR KANSAS WIND?

A. Yes, I did. Mr. Berry used the same methods for all of his levelized cost calculations. In addition, I found a calculation error in his Net Present Value calculation of total expenses. After correcting for this error, the following table shows the component of Mr. Berry's calculation:

Revenue Requirements	$/MWh
Implicit Capacity Cost	$28.54
Expenses	$89.20
Total Revenue Requirement	**$117.74**
Credits	**$/MWh**
Capacity Revenues	$27.98
Production Tax Credits	$0.00
Berry's LCOE ($/MWh)	**$89.76**

Q. HAVE YOU CALCULATED THE LEVELIZED COST FOR A COMBINED CYCLE GENERATION?

A. Yes, I have. There are four components to this calculation.

Combined Cycle	$/MWh-Yr
Capacity Costs	$13.48
O&M Costs	$5.45
Fuel Expense	$54.44
CO2 Costs	$12.60
Total Costs	$85.97

Mr. Berry's capacity costs are $15/MWh higher than my calculations, and adding up all of the expenses gives $85.97/MWh compared to Mr. Berry's estimate of $117.74/MWh before revenue credits; a difference of over $21/MWh.

Q. WHY ARE CO2 COSTS INCLUDED IN YOUR CALCULATIONS?

A. Currently CO2 costs are **not** being charged to fossil fuel generation. This will likely change with the new regulations being proposed by the Environmental Protection Agency (EPA), and therefore CO2 cost is a risk factor that should be included in making a risk comparison.

Q. HOW DID MR. BERRY ASSESS THE RISK OF CO2 COSTS?

A. Mr. Berry uses an estimated cost of $15/ton as a mid-range projection of CO2 costs. He inflates this cost over the 30 year life of the combined cycle alternative and derives a levelized estimate of just over $20/MWh.

Q. IN YOUR OPINION IS THIS A PROPER RISK ASSESSMENT FOR CO2 COSTS?

A. No, it is not. First, at $15/ton I calculate a levelized cost of $12.60/MWh. When this is added to the levelized cost for the combined cycle unit, its cost goes up to $85.97/MWh, which is still below $92.26/MWh (Kansas Wind without production tax credits). Second, a lower CO2 price of $10/ton results in a levelized cost of $8.40/MWh and lowers the combined cycle levelized cost to $81.77/MWh, which is well below the Kansas Wind levelized cost. Third, a higher CO2 price of $25/ton results in a levelized cost of $19.44/MWh, and raises the levelized cost for combined cycle to $92.82/MWh, which takes the Combined Cycle levelized cost just above the levelized cost for Kansas wind without the production tax credit. Thus the economic viability of western Kansas wind compared to combined cycle generation rests on what is estimated as a high charge for CO2 emissions for combined cycle generation.

Q. EVEN WHEN USING THE HIGH CO2 COST WHY ARE YOUR LEVELIZED COSTS SIGNIFICANTLY LOWER THAN MR. BERRY'S ESTIMATE?

A. A major difference appears in the calculation of capacity costs for combined cycle generation. My levelized cost estimate for return on and of investment is $13.48/MWh compared to Mr. Berry's implicit estimate of $28.54/MWh. In order to determine the differences in expenses, I had to decompose Mr. Berry's Total Expense into O&M Expense, Fuel Expense and CO2 Expense.

Q. WHAT DID YOUR ANALYSIS OF EXPENSES FOR COMBINED CYCLE GENERATION SHOW AS THE AREAS OF DIFFERENCE?

A. The following table shows the differences in levelized costs for the three major cost components for combined cycle generation.

Expense Components	Levelized $/MWh		
	Proctor	Berry	Diff
O&M Expense	$5.45	$8.53	$3.07
Fuel	$54.44	$60.60	$6.16
CO2 Mid	$12.60	$20.07	$7.48
Total Expenses	$72.49	$89.20	$16.71

I have previously discussed the differences in the calculation of CO2 costs. However the differences in Fuel and O&M Expenses are also significant. The reason Mr. Berry's estimates in these two categories are higher is he has improperly used the inflation rate to escalate these costs over the life of the asset.

I did not escalate the O&M Expenses (fixed and variable), as there was no forecast evidence to support an increase in nominal level for these cost. For fuel I used the EIA's projection of natural gas prices for electric plant fuel and since these were reported in real dollars, I did have to convert to nominal dollars. I did so using the EIA's inflation factors which it used to deflate their forecast in nominal dollars. The EIA's inflation factors, averaging 1.66%/year, were significantly lower than Mr. Berry's assumed 2.5% per year. This difference in escalation rates accounts for the difference in fuel expense.