BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an interconnection on the Maywood-Montgomery 345 kV Transmission Line	)	Case No. EA-2014-0207

SHOW ME CONCERNED LANDOWNERS RESPONSES TO GRAIN BELT EXPRESS CLEAN LINE LLC'S THIRD SET OF DATA REQUESTS

For its responses to the Third Set of Data Requests of Grain Belt Express Clean Line LLC ("Grain Belt Express" or "Company") to Intervenor Eastern Missouri Landowners Alliance d/b/a Show Me Concerned Landowners ("Show Me"), Show Me states the following:

Response to Clean Line's Data Request of Dr. Proctor

1. For each input value in the work papers of Dr. Proctor, please list the source if a source was used or relied upon. If no source was used, please indicate this.

The inputs are the same as those used by Mr. Berry except where the differences are pointed out in my rebuttal testimony.

a) Natural gas price forecast: Used EIA's most recent forecast as provided in **Attachment 1.**
b) Inflation rate: Used EIA's forecast of Henry Hub natural gas prices in real and nominal values to calculate their inflation rate. Data also in **Attachment 1.**
c) Used EIA Updated Cost Estimates for Advanced CC Plant Costs as provided in **Attachment 2.** Also included EIA Assumptions to the Annual Energy Outlook 2014; p. 97 in **Attachment 2.**
d) Used Synapse 2013 CO_2 Allowance Price Projections as provided in **Attachment 3.**
e) Used Figure 26 in 2012 Wind Technologies Market Report to calculate escalation rates for O&M costs for wind. Measurement provided in **Attachment 4.**

2. Regarding the work papers previously provided, please identify the location of all results cited in Dr. Proctor's rebuttal testimony, including but not limited to the items described below. If the results are not derived from the previously provided work papers, please provide the relevant calculations and support in as much detail as possible.

(a) The levelized O&M expense estimate of $11.73/MWh (p. 13, line 11).
(b) The levelized capacity cost of Kansas wind of $34.63/MWh (p. 8, line 14).
(c) The levelized PTC value of $16.51/MWh (p. 14, line 21).
(d) The $19.30/MWh figure for additional Kansas wind capacity cost (p. 16, line 22.)
(e) The total Kansas wind levelized cost of $65.65 (p. 16, line 23).
(f) The Kansas wind delivered cost of $87.65 (p. 19, line 11) and $92.26/MWh (p. 19, line 18).

All calculations requested in (a)-(f), excluding (c), are found in the "Calculations" Tab of the Levelized Fixed Charges MPWP workbook. The Tabs preceding the Calculations tab calculate the Levelized Fixed Charge rate for each category of cost. The calculation for (c) are in a Tab labeled PTC.

(g) All figures in the table at p. 20, lines 10-11.

Calculation are found in Unpacking Berry LCOE MPWP in cells B51 through C61

(h) The following figures in lines 9-19 on p. 21: \$12.60 per MWh, \$85.97 per MWh, \$8.40 per MWh, \$81.77 per MWh, \$19.44 per MWh and \$92.82 per MWh.

CO2 Tab is found in Levelized Fixed Charges MPWP workbook
\$12.60/MWh at cell I41; \$85.97/MWh at cell I45
\$8.40/MWh at cell H41; \$81.77/MWh at cell H45
\$19.44/MWh at cell J41; \$92.82/MWh at cell J45

(i) The cost for capacity cost of combined cycle of \$13.48 per MWh and \$28.54 per MWh (as implied in Mr. Berry's model) described on p. 21-22.

\$13.48/MWh at cell G12 of Calculation Tab in Levelized Fixed Charges MPWP;
\$28.54/MWh at cell C52 in Unpacking Berry LCOE MPWP

(j) All values in the table at p. 22, lines 7-8.

Cells R3 through U8 of Comparisons Tab in Levelized Fixed Charges MPWP

(k) The $1.06 per MWh figures cited at p. 23, line 4.

Fixed O&M Tab: paste cell E6 (average EIA inflation rate) into cell E7 to get levelized fixed O&M cost with inflation added. Take difference from levelized fixed O&M cost without inflation added; i.e., $2.48 - $2.08 = $0.40
Fixed O&M Tab: paste cell J6 into cell J9 to get levelized variable O&M costs with inflation added. Take difference from levelized variable O&M cost without inflation added; i.e., $4.03 - $3.37 = $0.66
Add $0.40 + $0.66 = $1.06.

(l) All values in the table at line 23, lines 12-13.

Cells F4 through T8 of Calculations Tab in Levelized Fix Charges MPWP

(m) The figures $73.37/MWh, $92.26/MWh, $85.97/MWh, $92.82 per MWh and $76.57 per MWh on p. 24

All Tabs below are in Levelized Fix Charges MPWP workbook
$73.37/MWh in cell X8 of Calculations Tab
$92.26/MWh in cell T6 of Calculations Tab
$85.97/MWh in cell I45 of CO2 Tab
$92.82/MWh in cell J45 of CO2 Tab
$76.57/MWh needs to be corrected to $75.75 and is calculated as $92.26 - $16.51, where $92.26/MWh in cell T6 of Calculations Tab and $16.51 in cell F36 of PTC Tab.

(n) All figures in the table on p. 27, lines 2-3.

Cells J3 through O10 of Wind Alternatives Tab in Levelized Fix Charges MPWP

(o) All figures in the table on p. 28, lines 7-8.

Cells AI3 through AO11 of Wind Alternatives Tab in Levelized Fix Charges MPWP

(p) All figures in the table on p. 29, lines 13-14.

Cells C4 through F11 of Annual Summary Tab in FTR Annual and Summer Results MPWP workbook

(q) All figures in the table on p. 34.

Cells X3 through AB11 of Wind Alternatives Tab in Levelized Fix Charges MPWP

(r) All figures in the table on p. 35 line 15-16.

Cells R19 through U26 of Wind Alternatives Tab in Levelized Fix Charges MPWP

3. Regarding the "Transmission" tab, cell T3 in Dr. Proctor's work paper entitled "Levelized Fixed Charges MPWP," please provide the basis for the calculation of the $270 figure and explain how it was used in Dr. Proctor's rebuttal testimony.

The basis for $270 per MW of installed generation capacity is explained in my rebuttal testimony at page 35; lines 1-12. How it was used is explained in my rebuttal testimony starting at page 35, line 12 going through page 36, line 23.

4. Regarding the "Variable O&M" tab, cells D56 through F66, in Dr. Proctor's work paper entitled "Levelized Fixed Charges MPWP":

(a) Please provide the raw data used.

Columns D-F are the raw data – measurements taken from graph – see **Attachment 4.**

(b) Please provide the source of this data.

See response to DR 1.e)

(c) Please explain how Dr. Proctor converted these data into a long-term escalation rate of 5%.

See cell J96 for the formula used to calculate – $\{[X(25)/X(1)]^{(1/25)}\}-1$, where X(1) is the nominal value for O&M costs in year 1 and X(25) is the value in year 25. A trend was used to estimate the nominal value for O&M expenses in year 25.

5. Does Dr. Proctor believe that independent power producers (IPPs) and merchant transmission lines such as Grain Belt Express determine the levelized cost of their energy and capacity using the techniques described at p. 4, line 17 through p. 5, line 11 of his rebuttal testimony?

(a) If the answer is anything other than an unqualified no, please explain in detail how IPPs and merchant transmission lines as non-rate regulated entities can use the same techniques as rate regulated utilities.

The purpose of this portion of my rebuttal testimony was to describe <u>how a regulated utility determines levelized costs</u> based on revenue requirements. I cannot answer the above question without knowing the purpose for which an IPP or merchant transmission company is determining the levelized cost of its energy and capacity. If the purpose is for a regulatory hearing before a public utility commission, then it should use the method described in my testimony. Clearly, Mr. Berry did not use the method described in my testimony. I do not know what other IPPs or merchant transmission companies may use internally, nor do I know that the method used by Mr. Berry is typical of what is used by IPPs or other merchant transmission companies.

6. Does Dr. Proctor have any experience in running financial models on behalf of merchant transmission lines and independent power producers (IPPs) that are not subject to rate base, rate of return regulation?

I have not consulted with IPPs or merchant transmission companies.

(a) If the answer to Request 5 is yes, please describe this experience in detail, including the names of the companies or projects for whom such models were prepared.
(b) If the answer to Request 5(a) is yes, please describe the financial techniques Dr. Proctor used.
(c) Please compare the financial techniques described in the response to Request 5(b) with the techniques referred to in Dr. Proctor's testimony at pages 25-30 to estimate the cost of Kansas wind delivered to Missouri via the Project with "Missouri wind" and "Midwest ISO wind."

Do you mean Request 6, 6(a) and 6(b)? If so, then since my answer is NO, Requests 6, (a)-(c) do not apply.

7. Please provide supporting documentation and citation to authority for the following statements in Dr. Proctor's rebuttal testimony:

(a) "In the SPP analysis the lowest and most recent levelized cost for wind generation has been \$35/MWh, not including annual O&M expense." (p. 7, line 7).

This was discussed at the SPP's ESWG meeting on September 9, 2013. The following table was included by SPP Staff at that meeting.

Levelized Cost of Energy Calculator

	Onshore Wind	Assumptions w/ PTC	Assumtions w/o PTC	Notes
A	Weighted Average Cost of Capital	9.85%	9.85%	9.6%-10.1% is typical
B	Levelized Fixed Charge Rate	11.38%		Calculated Below
C	*Levelized* Cost of Energy	31.00	51.00	ESWG Assumption
D	Capacity Factor	49.40%	42.00%	ESWG Assumption
E	Fixed O&M (\$/kW-yr)	25.00	25.00	Supported by DOE report
F	*Levelized* Fixed O&M (\$/MWh)	5.78	6.79	Calculated (E*1000)/(D*8760)
G	*Levelized* Value of Federal PTC (\$/MWh)	23.00	0.00	Standard PTC
H	*Levelized* Capital Cost (\$/MWh)	48.22	47.20	Calculated (C+G-F)
I	Levelized Capacity Cost (\$/kw-yr)	208.68		Calculated (H*D*8760)/1000
J	Capital Cost (\$/kW)	\$1,833	1,763	Calculated (I/B)

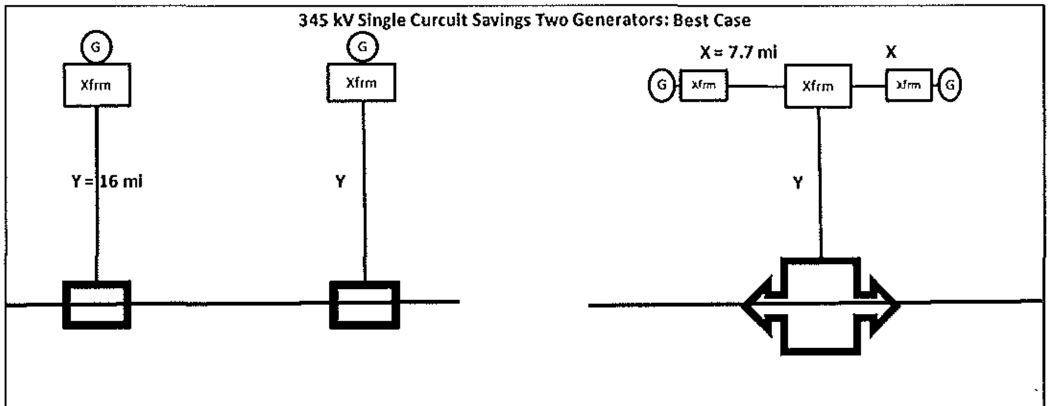
Red text indicates input fields
Blue text indicates calculated values

At a 49.4% capacity factor, this table indicates a levelized cost for capital of \$48/MWh (row H). This is higher than what I recalled from the discussion. If the PTC (row G) is subtracted and the Fixed O&M (row F) is added, the LCOE is \$31/MWh (row C). I will note that the Levelized value of the PTC in this table assumes that the credit covers the life of the wind farm. It should be decreased by \$4/MWh to account for the PTC only applying to the first 10 years, raising the LCOE to \$35/MWh.

(b) "[SPP] interconnection costs are … in the order of \$300/kw …." (p. 15,lines 8-9).

I based this estimate on the work I performed for the CAWG regarding SPP's proposal for a Hub and Spoke Model for connecting wind farms. The data used in that analysis came from the SPP's Area Generation Task Force. The following calculations are from that work, where \$295/MW is the estimated cost for connecting two 100MW wind farms.

345 kV Single Curcuit Savings Two Generators: Best Case



No Hub Design Million of \$

Item	#	Cost	Total
Xfrms 34.5/345	2	\$8.000	\$16.000
Gen Leads @ 345 kV	2	\$11.500	\$23.000
Attachments	2	\$10.000	\$20.000
Total Cost			\$59.000

200,000 kW
\$295 /kW

Hub and Spoke Design Million of \$

Item	#	Cost	Total
Xfrms 115/345	1	\$12.000	\$12.000
Xfrms 34.5/115	2	\$2.000	\$4.000
Gen Leads @ 115 kV	2	\$3.833	\$7.667
Spokes @ 345 kV	1	\$11.500	\$11.500
Hub	1	\$16.000	\$16.000
Total Cost			\$51.167
Hub & Spoke Cost			\$39.500

Million of \$
Savings \$7.833

(c) "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." (p. 17, lines 6-8).

I do not have a cross-sectional study of wind generation during summer peak hours from regions with varying annual capacity factors that includes both wind during summer peak as well as annual generation. However, MISO has some limited data on wind generation in its footprint for various peak hours for July and August as well as monthly GWh wind generation for July and August 2013 (Data in **Attachment 5**). In the table below, the MW from Wind at Peak is the average of the MISO individual peak days' data for July and August. If wind at peak is correlated with average wind generation across regions, then it should also be correlated across months for the entire region. However, when you compare the data for July and August it shows a significant drop in Monthly Average Energy compared to MW from Wind at Peak going from July to August. Alternatively, if the ratio of Aug AVG to Jul AVG is multiplied by the July MW from Wind at Peak, the estimate for Aug MW from Wind at Peak would be 2,271 MW, which is well below the observed level.

Months for 2013 Peaks	MWh/Hr Wind	MW from Wind at Peak	Wind at Pk ÷ MWh/Hr
Jul AVG	2,586	3,330	128.78%
Aug AVG	2,113	3,047	144.19%
Difference	473	284	-15.41%

While this is a very small sample from a single year, it illustrates my concern with using the ratios of annual capacity factors to calculate the % accredited capacity for one region (e.g., Kansas) based on the % of accredited capacity from another region (e.g., Missouri) that has a significantly different annual capacity factor. As stated in my rebuttal testimony, a better approach is to use data from a region that has similar capacity factors.

(d) "The wind in northwest Iowa also has the same annual average wind speeds as western Kansas." (p. 18, lines 1-2).

See average wind speed map on page 17 of my rebuttal testimony.

(e) "The SPP has found preliminary cost estimates for transmission projects to be 30% lower than actual costs." (p. 18, line 23).

SPP set up a Project Cost Task Force in 2011. They determined that a transmission upgrade in what is called the "Study Phase" requires a 15% to 30% contingency. **See "Addressing Cost Estimates and Cost Increases;" Slide 13, Feb 18, 2011.** This range was based on the experience of transmission owners in the SPP. This led the PCTF to include a ± 30% bandwidth for cost estimates at the study phase level. Table 1 in the **"Project Task Force Whitepaper," July 19, 2011.** Both documents can be found on SPP website under Documents; Org Group Documents; Project Cost Working Group; PCTF Documents.

8. Please identify and describe the "calculation error" discussed on p. 20, line 4 of Dr. Proctor's rebuttal testimony.

> This was a difference in discounting. Mr. Berry discounted back to 2018 while I discounted to 2019.

9. Does Dr. Proctor believe that if generator availability and dependable capacity is accounted for properly, a levelized cost of energy analysis ("LCOE") is an appropriate means to compare the cost-effectiveness of wind energy and dispatchable generation? If he does not, please explain in detail why he does not.

> See my rebuttal testimony at page 2, lines 19-21. Moreover, in order to compare wind to dispatchable generation, the dispatchable generation must be fully dispatched when available. It can also be argued that there are additional benefits (avoided costs) to dispatchable generation vs. non-dispatchable generation. In doing an LCOE comparison it is assumed that the wind technology included its dispatchability.

10. The table on p. 23 of Dr. Proctor's rebuttal testimony appears to assume that no property taxes were incorporated in the "Missouri Wind" alternative. Is this the case? If so, please provide a complete explanation of and supporting documentation for this assumption.

> This comparison does not include property tax for Missouri Wind. See answer to 11 for calculations for property taxes. The Missouri Wind is at 30% CF, but since investment is reduced by 1/1.25 the LOCE property tax for Missouri Wind is lower.

11. In the "MISO Wind" alternative discussed in Dr. Proctor's rebuttal testimony beginning at page 26, what assumption was made about property taxes? Please explain and provide supporting documentation.

> The comparisons made for MISO wind did not include property tax. Property taxes for business are a primarily a local determination in Missouri, and at times business can receive incentives for locating by giving the business property tax relief. If the property tax used by Mr. Berry for Missouri wind is applied the following Levelized costs should be added to the Missouri and MISO wind alternatives:

Property Taxes

CF	$10,394	MO Wind
30%	$3.96	$3.16
35%	$3.39	
40%	$2.97	
45%	$2.64	
50%	$2.37	

12. Please explain in detail the statement at page 26, lines 19-20 of Dr. Proctor's rebuttal testimony that "Missouri wind is treated differently as it gets an added 25% renewable energy credit."

> Missouri statue at 393.1030.1 states: "Each kilowatt-hour of eligible energy generated in Missouri shall count as 1.25 kilowatt-hours for purposes of compliance." For example: A requirement of 100 kWh can be met with 100 kWh/1.25 = 80 kWh, or 80 kWh * 1.25 = 100 kWh. Thus, both energy and capacity can be reduced by 1/1.25 to meet the renewable energy requirements if the resource is located in Missouri.

(a) How does this affect the values in the table on page 27?

> See cells J13 through I15 of Tab Wind Alternatives in Levelized Fix Charges MPWP The capacity and energy required to meet Missouri RES would be reduced by 1/1.25, but the capacity adder would be increased by 1.25.

13. Regarding Dr. Proctor's reference in his rebuttal testimony to EIA (U.S. Energy Information Administration) inflation factors at pages 22-23 and elsewhere, please provide the underlying source of his inflation assumptions and any relevant calculations he has performed.

> The source is found **Attachment 1**. I used the ratio of EIA's forecast of nominal to real natural gas prices for the Henry Hub to calculate the year-to-year inflation factors. Year-to-year inflation rates can also be calculated using the formula $(1+i_t)^t = P_{nominal}/P_{real}$, where i_t is the year-to-year inflation rate. The analysis is found in cells B1 through J41 of Fuel Expense Tab in Levelized Fix Charges MPWP.

14. Regarding Dr. Proctor's rebuttal testimony beginning at page 5, line 12, where he claims that the "capitalization factor" calculated by Mr. Berry is incorrect:

(a) In the "Kansas Wind + Grain Belt" tab of the spreadsheet Grain Belt Express provided in response to Show Me Data Request 1-2, is cell B78 the "capitalization factor" to which Dr. Proctor testimony refers? If the answer is anything other than an unqualified yes, please explain why not.

> That is correct

(b) What value does Dr. Proctor believe this capitalization factor should be? Please provide supporting documentation for the capitalization factor that he believes should have been used and any related calculation.

> The capitalization factor for wind should be 10.87 calculated as the sum of the discount factors over a 25 year period. Mr. Berry's calculations of a levelized cost of energy included the year 2018 when there are no MWhs being generated in that year. Thus, his capitalization factor, which includes 2018, adds a full levelized cost for 2018,resulting in a lower levelized cost..

(c) Does Dr. Proctor agree that when calculated correctly the annual revenue requirement in an LCOE model should yield an unlevered, after-tax internal rate of return equal to the WACC (weighted average cost of capital)? If the answer is anything other than an unqualified yes, please explain why not.

- The annual revenue requirement in an LCOE model should include enough revenue to cover the return on equity, interest on debt, a return of capital, expenses including taxes.
- The ***internal rate of return*** is the discount rate applied to the levelized profits over the life of the investment that is equal to the original amount of the investment. <u>For the above defined revenue requirements, profits are equal to the return of and on investment.</u> For example: for an investment of \$100 to earn a 10% return in one year, the after tax profits must be \$110 = \$100 return of + \$10 return on. The internal rate of return is the discount rate that makes the present value of the \$110 equal the original investment of \$100, i.e., \$110/(1+r) = \$100 or 1+r = \$110/\$100 = 1.10; so r = 0.1 or 10%.

- The ***capitalization factor*** is the sum of the discount factors over the life of the asset. When this is multiplied by the levelized return of and on investment it is equal to the amount of the original investment.
- Explanation: the levelized return of and on an investment is calculated as the ***Levelized Fixed Charge Rate*** times the amount of the original investment, where the ***Levelized Fixed Charge*** is the ratio of the discounted un-levelized stream of returns on and of investment divided by the capitalization factor, and the Levelized Fixed Charge rate is the Levelized Fixed Charge divided by the original investment. These calculations make the discounted stream of levelized returns on and of investment equal to the discounted stream of un-levelized returns on and of investment. These calculations hold true irrespective of the discount rate used.

  Given the above, the question asked becomes: whether or not a proper LCOE should use a discount rate equal to the weighted average cost of capital (WACC)? Put another way, should the discount rate equal the internal rate of return on the investment? My answer is that WACC is the appropriate discount rate to use for cash flows that have similar risks to those of the overall firm. While the risks for a regulated utility may be different than risks for merchant generation (e.g., Kansas Wind) or merchant transmission (e.g., Clean Line), using the same discount rate for calculating LCOE simplifies the analysis.

(d) Regarding the "Kansas Wind + Grain Belt" tab of the spreadsheet Grain Belt provided in response to Show Me Data Request 1-2, does Dr. Proctor agree that the cell R9 is equal to the model's assumed weighted average cost of capital? If the answer is anything other than an unqualified yes, please explain why not.

> More appropriately the WCOC is correctly calculated on the Inputs and Summary tab at B12. Since this is the same value as cell RP on the Tab referred to above, then YES.

(e) Will changing the capitalization factor in cell B78 result in the IRR (internal rate of return) in cell R9 no longer being equal to the model's assumed weighted average cost of capital? If the answer is anything other than an unqualified yes, please explain why not.

> As stated in response to Request 14 (b), the LCOE should be calculated over the operational life of the asset: 2019-2043 = 25 years. If Mr. Berry had included Capital Costs in 2019 instead of 2018, and used a 25 year capitalization factor instead of a 26 year capitalization factor, then his LCOE would be higher, resulting in his calculation of LOCE over the proper time period, and would also result in the internal rate of return being equal to the weighted cost of capital.

15. On pages 15-16, Dr. Proctor discussed the way Mr. Berry's LCOE model accounts for capacity value, namely that it is subtracted from the total revenue requirement to lead to a lower levelized cost of energy. On page 16, beginning at line 12, Dr. Proctor describes what he perceives is the correct method, subtracting the "accredited capacity of the resource with the lower percentage of capacity" from the accredited capacity of the "resource with the higher percentage of accredited capacity."

(a) What is the basis for Dr. Proctor's method?

> Alternative generation sources should be compared on an equivalent basis. If one resource has a lower accredited capacity when compared to another resource having the

same name plate capacity, then the difference in capacity should be taken into account in order for the two alternatives to be considered equivalent.

(b) Do the two methodologies yield the same or similar results because they both penalize the lower capacity resource relative to the more dependable resource?

Mathematically, if the capacity values are the same for both methods, then the difference between the LOCEs of the two resources should be the same.

(c) Please state why Dr. Proctor believes Mr. Berry's methodology is incorrect or leads to inaccurate results.

Mr. Berry's methodology gives misleading results in terms of the costs to the utility for Wind and Combined Cycle generation. In order for Mr. Berry's analysis to represent the cost to the utility he must assume that the capacity from the two alternatives is not needed by the utility and can be sold into a capacity market at the cost of a combustion turbine. While this difference may not matter for determining economic viability (i.e., comparing Wind to Combined Cycle generation), it is crucial in determining need (i.e., determining the impact of the Wind alternative on retail rates).

(d) Has Dr. Proctor ever sold energy on behalf of a wind farm?

No

16. Referring to p. 17 lines 11-14 of Dr. Proctor's rebuttal testimony, please state why Dr. Proctor believes the summer temperatures in the Dakotas, Minnesota and Iowa should be analyzed and considered with respect to the capacity value of Kansas wind.

The basis for including summer temperatures in the statement:

"I choose 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,"*

is: 1) accredited capacity is calculated based on wind generation during the summer peak hours; 2) it is well understood that wind production during the summer peak hours is lower; and 3) temperatures are higher during summer peak hours.

Therefore, not having higher summer temperatures in the Dakotas, Minnesota and Iowa compared to Kansas implies temperature should NOT be a source of downward bias in using the accredited capacities from these regions in comparison to Kansas.

17. Does Dr. Proctor agree that wind power that participates in a security-constrained economic dispatch nodal market will tend to displace generation located near its point of interconnection with that nodal market? If not, please explain why not.

The term "near" is undefined, but I will assume that it means within the same local transmission zone as where the wind is interconnected. While displacement of near generation by lower cost generation is a generally held belief, it depends on the economics and the robustness of the transmission system. Moreover, if displacement of near generation were always true, then there would be no reason for a wholesale power market.

Wind will displace the highest cost generation whose energy can be reduced subject to the constraints on the power grid. That may not always be from generation located near to the point of interconnection of the wind on the power grid. Moreover, in RTO transmission planning, a base case with wind added is compared to a change case where transmission is also added to determine the economics. In the base case, added wind will "tend" to displace generation near to where the new wind is interconnected when there is sufficient congestion to prevent higher-cost, distant generators from reducing much of their energy output. But, in the change case, where transmission upgrades are added to reduce the congestion, the reduction in energy can now increase from these distant generators. The economics compares the added savings of reducing additional generation from the higher-cost, distant generation to the cost of a transmission upgrade needed to relieve the congestion. If the added savings exceed the cost, then the transmission upgrade is built and the wind displaces added energy from distant generation sources. This is does not mean that no energy will be displaced from near generation. How much depends on the incremental cost of the near generation to distant generation and the amount of reduced congestion that comes from the transmission upgrade.

18. Does Dr. Proctor believe that additional wind capacity in Iowa, Minnesota or the Dakotas would reduce power plant emissions in Missouri? If so, please state the basis for this opinion.

I have not performed an analysis of what generation would be displaced by wind energy in Iowa, Minnesota or the Dakotas. Such an analysis should include both a base case without transmission upgrades and change case with transmission upgrades. The answer also depends on the relative cost of marginal generation in Missouri compared to other places.

19. Regarding Dr. Proctor's statement at page 25 of his rebuttal testimony that the capacity factor of Kansas wind and the forecasted price of natural gas are "offsetting risks in comparing the two alternatives" of a new combined cycle gas generation plant with a Kansas wind plus DC transmission project like the Grain Belt Express Project, please explain in detail why these are off-setting risks.

Assumptions and forecasts are made for all inputs. These assumption or forecasts are subject to uncertainty. Absent a risk analysis, comparisons are based on averages or expected values for these inputs. What I meant by "offsetting risks" for Kansas Wind capacity factor and natural gas price inputs is that the assumption that these events are equally likely is reasonable. I did NOT mean to imply that these risks were somehow correlated.

20. Referring to page 29 of Dr. Proctor's rebuttal testimony, do MISO financial transmission rights (FTRs) offer protection against costs incurred in the loss component of LMPs (locational marginal prices) in the MISO energy markets?

No.

21. Please refer to Dr. Proctor's statement on page 25 of his rebuttal testimony that "Missouri requires 15% of generation to come from renewable resources as long as the cost of renewable energy does not exceed $5/MWh from non-renewable resources."

(a) Does Dr. Proctor claim that the Missouri Renewable Energy Standard (RES) does not require the purchase of renewable energy if it is more than $5 per MWh more expensive than non-renewable resources?

No. At the time I wrote my rebuttal testimony, this was my understanding of the Missouri RES. After reviewing the Missouri statues, the $5/MWh difference is a rough approximation of the Missouri RES. For example, the following table illustrates the $5/MWh differential as meeting the Missouri RES.

	% Energy	Adding CC	Adding Wind
	% MWh	$/MWh	$/MWh
Embedded	87.40%	$60.00	$60.00
New	12.60%	$86.00	$91.00
Average	100.00%	$63.28	$63.91
Difference (Wind - CC)		$0.63	
% Increase (Diff / CC)		1.00%	

The percent of energy coming from embedded costs will vary from year-to-year and will depend on retirements as well as declining rate base. The $60/MWh for embedded cost is a rough approximation, as it will also decrease over time with declining rate base. The $86/MWh for the CC alternative is from my analysis, and the $91/MWh for Wind is the addition of $5/MWh as stated in my rebuttal testimony. The $0.63/MWh is the difference between adding Combined Cycle vs. Wind generation, resulting in a 1% increase in rates when adding Wind instead of Combined Cycle generation . Any higher cost for wind would result in a greater than 1% increase. This analysis assumes that the capacity from the added resources is needed, and interprets the Missouri requirement of no more than a one percent increase to be a "comparative" rather than an "absolute" requirement. This interpretation appears to be consistent with the Missouri Commission's rules for implementing the Missouri RES (40 CSR 240-20)

(5)(B) The RES retail rate impact shall be determined by subtracting the total retail revenue requirement incorporating an incremental non-renewable generation and purchased power portfolio from the total retail revenue requirement including an incremental RES-compliant generation and purchased power portfolio.

(b) If so, please state the basis for Dr. Proctor's statement, including citations the relevant legislative or regulatory authority.

Missouri statues at 393.1050 states: "Any renewable mandate required by law shall not raise rates charged to the customers of electric retail suppliers by an average of more than one percent in any year ..."

22. Regarding Mr. Berry's escalation of operational costs for dispatchable power plants in his financial model (expressed in nominal dollars) with the rate of inflation, Dr. Proctor states at page 6 of his rebuttal testimony that this "results in an overestimate of the annual O&M costs for most of the alternatives."

(a) Does Dr. Proctor believe that if expenses are not escalated with inflation, they will decline in real dollar terms?

No. It depends on the escalation rate compared to the inflation rate. Simple mathematics: If you escalate costs at 3% per year (multiplying each subsequent year's cost by 1.03) and you deflate by 1.5% for inflation (dividing each subsequent year by 1.015), the real cost will go up by 1.03/1.015 > 1.

If instead the question is: when expenses are not escalated at all and the inflation rate is greater than zero, will the expense decline in real value, then the answer is obvious – if nominal costs don't increase, but the purchasing power of the dollar declines due to inflation, then expenses in real dollar terms will decline.

(b) Does Dr. Proctor believe that over time power plant O&M (operating and maintenance) expenses will decline in real dollar terms?

Not if the escalation rate exceeds the inflation rate. For example, my analysis of O&M expenses for Wind shows cost escalating at over 4% per year, but the average inflation rate is under 2% per year. In this case, the O&M expenses for wind will increase in real dollar terms.

(c) If the answer to Request 24(b) is yes, please provide supporting documentation or research for this opinion.

While my answer to 24(b) is NO, I assume that Request 24(c) relates to my not escalating O&M expenses for a Combined Cycle plant in my LCOE calculation. In this regard, see my response to Request 23.

23. Please provide supporting documentation or research which forms the basis of Dr. Proctor's statement at page 22, line 13-14 of his rebuttal testimony that he "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."

This statement applies only to the Combined Cycle plant. While it's impossible to provide documentation of something that did not happen, estimates were only given for a single year's O&M expense in the EIA document on "Assumptions to the Annual Energy Outlook" provided in Attachment 2. I did not find forecasts for O&M expenses in this document. I searched for other forecasts on the EIA website, but did not find any.

24. Please describe where and how a 2.5% inflation factor is applied to the combined cycle fuel expense in the spreadsheet that Grain Belt Express provided in response to Show Me Data Request 1-2.

When I compared Mr. Berry's spread sheet values Natural Gas cost to the EIA forecasts of nominal costs, I found an above 2% difference. I assumed this was from Mr. Berry's application of the inflation factor resulting in above 2% overall higher prices. See table below. EIA forecast data in nominal terms comes from the Annual Energy Outlook 2014 at page A-7.

Year	EIA Nominal	Berry	Diff	% Diff
2020	$5.75	$5.87	$0.12	2.09%
2025	$7.09	$7.25	$0.16	2.26%
2030	$8.74	$8.93	$0.19	2.17%
2035	$10.85	$11.09	$0.24	2.21%
2040	$13.53	$13.82	$0.29	2.14%
%/year	4.37%	4.37%		

Thus, it doesn't appear that Mr. Berry used the EIA nominal forecast, and when I compared his prices with the EIA real forecasts for 2020 to 2025 I found an inflation rate difference of approximately 2.5%.

Year	EIA Real	Berry	Inf Factor	Inf Rate
2020	$5.07	$5.87	1.157791	2.41%
2025	$5.56	$7.25	1.303957	

25. Please provide a copy of the consulting contract with the Regional State Committee of Southwest Power Pool (SPP), as referred to on page 1 of Dr. Proctor's rebuttal testimony.

Consulting contract with SPP is provided as **Attachment 6.**

26. Regarding his consulting contract with the Regional State Committee (RSC) of SPP, what work has Dr. Proctor performed for the RSC in 2013 and 2014?

My work for the RSC included attendance at RSC, CAWG and ESWG meetings. The primary focus was availability for any questions from the RSC or CAWG on issues dealing with cost allocation of transmission costs, benefit metrics, allocation of benefit and cost-benefit analysis. If asked to make a presentation on any of the above issues, I provided power point presentations. Presentations made to CAWG are listed below and can be found on the SPP website under Documents; Org Group Documents; CAWG Documents.

Date	Presentations
01/09/13	An Overview of SPP Planning for ITP20
03/06/13	ESWG Update
06/12/13	Long-Term Transmission Rights
08/07/13	Assignment of Benefit Metrics
09/04/13	Review of Brattle Cost/Benefit Report
10/02/13	Allocation of Policy Benefits
02/12/14	Adding vs Combining Benefits
06/04/14	Allocation of Policy Benefits
06/04/14	Allocation of Reliability Benefits

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been emailed to counsel for Grain Belt Express on this 3rd day of October, 2014.

/s/ Terry M. Jarrett
Terry M. Jarrett