BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE COMPLAINT FILED BY JUHL ENERGY, INC., AGAINST NORTHWESTERN CORPORATION d/b/a NORTHWESTERN ENERGY REGARDING AVOIDED COST AND FOR THE BRULE COUNTY, WIND, LLC, AURORA COUNTY WIND, LLC, AND DAVISON COUNTY WIND, LLC PROJECTS	: : : : :	Docket No.-______ **PREFILED DIRECT TESTIMONY OF ROGER SCHIFFMAN ON BEHALF OF JUHL ENERGY**

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Roger Schiffman. My business address is 1701 Arena Drive, Davis, CA 95618.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am the managing director of Power Markets Research Group ("PMRG"). PMRG is a private consulting firm specializing in energy markets, resource planning issues, and in calculating estimates of long-term avoided costs. I started that position after seven years with Black and Veatch Corporation in Sacramento, California.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION

A. I received my bachelor of business administration, finance, investment and Banking in 1988 from the University of Wisconsin-Madison. I continued my studies at the University of Wisconsin-Madison working toward a Master of Science in Finance from 1988-May 1990. I left the graduate studies program to join the Wisconsin Public Service Commission, where I became a senior financial analyst. My curriculum vita is attached to this testimony as Exhibit "1."

Q. PLEASE BRIEFLY DESCRIBE YOUR WORK HISTORY

A. Prior to my assignment as manager at PMRG, I was a principle at Black and Veatch and assisted in directing, preparing and developing market analysis, integrated resource planning, nodal market planning, avoided cost, transmission planning, transmission congestion, other transmission issues, resource planning/power supply analyses, and generation reliability analysis. I have provided consulting services in energy market analysis, utility resource planning, and power price forecasting for the last 18 years, at consulting firms including Henwood Energy Services, Navigant Consulting, Ventyx, and Black & Veatch. At PMRG, I have continued my work on these subject matter areas. At each of these firms, I have been responsible for developing long-term projections of electricity prices in U.S. wholesale markets. Those projections have been used in developing estimates of avoided cost, in utility integrated resource planning, and in supporting valuation and due diligence review of purchase and sale transactions for individual power plants, and for portfolios of power plants.

Q. HOW MANY YEARS HAVE YOU BEEN WORKING ON UTILITY RESOURCE PLANNING AND UTILITY RESOURCE/AVOIDED COST ESTIMATES?

A. I have more than 25 years of experience working in the public and private sectors directing, preparing and developing reports and testimony on market analysis, integrated resource planning, nodal markets, avoided cost, transmissions, resource planning/power supply analyses, and generation reliability analysis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by Juhl Energy to analyze NorthWestern Energy's ("NorthWestern") avoided cost estimates for the three 20 MW wind projects being developed by Juhl in South

Dakota. I was also retained to create an independent avoided cost forecast which, in my estimation, more accurately captured NorthWestern's long-term avoided cost.

Q. CAN YOU SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND ANALYSIS?

A. Yes. NorthWestern has developed a set of projected avoided costs for its system that it proposes to use as a pricing offer for the purchase of energy from the Juhl Energy projects. PMRG has been asked by Juhl Energy to review the NorthWestern avoided cost projections and methodology, and to determine if the approach taken is consistent with industry best practice. The discussion which is set forth below in detail highlights key findings of that review, and also seeks to quantify areas where adjustments to NorthWestern's methodology are appropriate.

Based on the review described below, PMRG has concluded that there are a number of deficiencies in the NorthWestern avoided cost methodology, its specific application to Juhl Energy, and the data assumptions used. These aspects result in the NorthWestern estimates being below its actual avoided cost for the Juhl Energy projects.

PMRG has developed alternative estimates of avoided cost for Juhl Energy, based on development of a true differential revenue requirement analysis, and using an independently developed forecast of electricity prices. The independent forecast assumptions were developed by Ventyx, an ABB Company, and PMRG replicated the Ventyx Reference Case forecast using the PROMOD IV production simulation model licensed by Ventyx.

These avoided cost estimates are higher than the values proposed by NorthWestern. PMRG recommends that the value developed using the Ventyx Reference Case forecast be used in determining avoided cost for Juhl Energy. A summary of the avoided cost estimates prepared by PMRG is listed below in Table 1.

Table 1 – Summary of Juhl Energy Avoided Cost Projections

Differential Revenue Requirement Levelized Avoided Cost - NPV @7.24% ($/MWh)	**$47.29**
CO2 Compliance Cost Incremental Impact ($/MWh)	$11.63
Adjusted Avoided Cost, with CO2 ($/MW)	**$58.92**
Capacity Value of Juhl Projects	$1.78
Total Levelized Avoided Cost, with CO2 and Capacity Value ($/MWh)	**$60.70**

Q. CAN YOU SUMMARIZE FROM YOUR PERSPECTIVE OF THE HISTORY AND REQUIREMENTS OF PURPA AS IT RELATES TO AVOIDED COST?

A. Yes. The concept of Avoided Cost has its roots in the Public Utilities Regularly Policies Act ("PURPA") passed by Congress in 1978. PURPA was instituted when the nation's power generation relied heavily on imported oil that had undergone significant price volatility. Significant increases in the cost of new power plants and the general feel that the traditional utility model was failing to foster an environment of competition also led to general dissatisfaction with the utility model in the United States during the 1970s. Consequently, Section 2(1) of PURPA explained that the purpose of the act was to further the goals of conserving electric energy, increase utility efficiency, and achieve fair rates for utility customers. The concept was to achieve these goals through policies that would foster the development of non-utility cogeneration and small power production.

Under Section 210 of PURPA, a utility is required to purchase electricity from certain non-regulated power producers, termed qualifying facilities ("QFs"). A QF can be either a cogeneration facility meeting certain efficiency requirements, or a small power producer (80 MW or less) whose energy input was primarily from waste, biomass, or renewable resources (the size limitation has since been removed).

PURPA requires utilities to purchase QF power at a nondiscriminatory, just and reasonable rate that does not exceed the purchasing utility's avoided cost. This avoided cost is an upper limit on purchases and is defined in Section 210 (d) as "the cost to the electric utility of the electric energy which but for the purchase from such co-generator or small power producer, such utility would generate or purchase from another source." A utility's full avoided cost includes incremental costs of electric energy, capacity, or both that, if not for the purchase from the QF, the utility would purchase or generate itself.

Q. PLEASE SUMMARIZE FERC'S GUIDANCE TO STATE REGULATORY COMMISSIONS IN ESTABLISHING AVOIDED COST?

A. The FERC rules implementing PURPA did not select a specific method for establishing the avoided cost rate to be paid QFs but rather left the specific methodology to the discretion of each state. However, FERC has also made it clear that any methodology adopted by the individual states must be consistent with FERC's implementing regulations. FERC also provided certain guidelines to states to consider when developing avoided cost rates. These include:

1. Utilities can be required to pay QFs for the "capacity value" of their projects only when the availability of such capacity allows the utility to reduce its own capacity-related costs by deferring construction of a new plant or by deferring commitments to firm power purchase contracts.
2. Utilities can be required to pay capacity payments even if the QF provides electricity only on an "as available" basis. In such cases, calculation of the payment would be based on a probabilistic estimate of production from a large number of similar QFs.
3. Avoided capacity costs based on a plant designed to displace less efficient generating units must be adjusted to take into account the lower operating costs the utility would incur with the new plant. Thus, if a new plant is deferred by virtue of QF purchases, fuel savings also would be forgone and these "lost savings" should be reflected in the rate paid to the QF.
4. The avoided capacity and energy costs used to calculate QF purchase rates must be internally consistent. For example, to use the high capacity cost of a deferred base

load unit and the high energy cost of a peaking unit would exceed the utility's true avoided costs.

5. The just and reasonable rate for new capacity is the avoided cost even when the utility making the purchase is simultaneously making sales to the QF.
6. Rates for QF purchases may be levelized over the life of a fixed-term contract rather than set equal to the utility's avoided costs at the time of delivery. Rates may be negotiated at levels below full avoided costs if the QF agrees to the arrangement, presumably in return for some contractual provisions not mandated under the applicable rules in that jurisdiction.

Q. APART FROM THIS GENERAL GUIDANCE, DO FERC'S REGULATIONS PROVIDE GUIDANCE?

A. Yes. 18 C.F.R. § 292.304(e) provides a list of factors that a state Commission must consider when calculating the energy and capacity components of avoided cost rates. These factors include:

1. Avoided cost data submitted by utilities to state regulatory authorities.
2. Availability and characteristics of the QF's power during system peak periods including:
   a. The utility's ability to dispatch the QF;
   b. QF reliability;
   c. Duration and enforceability of a utility's contract with a QF;
   d. Ability to schedule QF outages in coordination with the utility;
   e. Usefulness of QF production during system emergencies;
   f. Aggregate value of QF capacity and energy on a utility system; and
   g. Smaller capacity increments and shorter lead times associated with QF capacity.

3. The relationship between a QF's production and a utility's ability to actually avoid costs.

4. Costs or savings from changes in line losses as a result of QF purchases.

Q. WHAT HAVE STATES DONE AS FAR AS IMPLEMENTING FERC'S AVOIDED COST GUIDANCE AND REGULATIONS?

A. States have adopted a wide variety of approaches in implementing FERC's directives and in establishing avoided cost methodologies. States have addressed the following conceptual issues:

1. Whether short or long-run marginal costs should form the basis for the avoided cost analysis.
2. The appropriate planning horizon and incremental block of output over which costs are to be measured.
3. The particular methodology used for computing the relevant marginal costs.
4. The treatment accorded to small increments of QF capacity that have no impact individually on a utility expansion plan but that could have an impact if there were a large number of smaller QFs.
5. Treatment of firm versus non-firm QF purchases.

These conceptual issues have been the basis for the varying approaches that Commissions have adopted, including:

1. Long-run marginal cost methods.
2. Proxy unit approaches (in which avoided capacity and energy cost payments are linked to a unit selected to represent the next unit on the system, perhaps without a detailed analysis confirming that the proxy unit is the best fit for the system).
3. Expansion planning analysis (in which avoided capacity and energy costs may be linked to the next unit on the system as identified through a generation expansion planning study).
4. Short-run marginal cost methods.
5. Single unit approaches (generally this involves identifying the unit on the dispatch margin and linking avoided energy cost payments to the production cost of that unit).
6. Incremental heat rate approaches (linking payments to the incremental heat rate on a utility system that may involve more than a single unit).
7. Production costing approaches (using a computer simulation to identify the production cost and avoided cost payments).
8. Purchased power approaches (in which a bidding system may be used to determine the basis for the utility's avoided cost).
9. Reverse-the-meter approaches (in which energy produced is sent to the utility and reverses the meter that registers energy consumption so that the meter records the net energy consumed once QF production is taken into account).

10. Differential revenue requirements approaches (whereby the difference in a utility's revenue requirements are calculated with and without the QF purchase), usually through the use of detailed production cost or market simulation models.

In addition, in some jurisdiction, resources are developed and selected by utilities as a result of competitive RFP and resource solicitation processes. In cases where the process is administered with safeguards that prevent self-dealing or preferential treatment for resources being developed by the subject utility (e.g., the use of an independent evaluator or the adoption or presence of rules precluding offers from the host utility), bid prices submitted through the RFP process may be deemed as representative of the utility's avoided cost and in compliance with PURPA.

Q. HOW HAS THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION ESTABLISHED AVOIDED COSTS?

A. In past orders, the South Dakota Public Utilities Commission (PUC) has issued some guidance on avoided cost determination under PURPA. The PUC found that rates for purchases from QF's with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The PUC views its primary role in this area as focusing on resolving any contract disputes which arise between the parties. The PUC made a number of specific findings related to avoided cost determination.

The PUC found that it should set certain parameters for the negotiation of QF contracts, and that it is reasonable to distinguish between short-term and long-term contract purchase rates. The Commission found that QF contracts less than 10 years in length are viewed as short-term, and QF contracts 10 years or longer are viewed as long-term.

The PUC found that capacity credits included in short-term QF contracts should be based on the cost of installed turbine peaking generation, and that capacity credits included in long-term contracts should be based on the avoided cost of base load generation, with payments further based on the average kW supplied by the QF for each month during the utility's on-peak period. The PUC also found that the capacity credits included in long-term contracts should be made constant over the duration of the contract.

The PUC also found that both short-term and long-term QF contracts should include an energy credit based on the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility. The PUC stated that the hourly energy cost data required to be filed under Section 133 of PURPA is an appropriate data source for determining avoided energy costs. As detailed below, PMRG developed an independent assessment of avoided cost that follows this approach.

In May, 2013, in response to a complaint filed by Oak Tree Energy, LLC, the PUC issued its latest decision on negotiated avoided cost for a wind QF project that has similarities to the Juhl projects. In its May, 2013 decision, the PUC found that NorthWestern avoided costs applicable for the Oak Tree project were $36/kW/Year for capacity, in 2013 and 2014, with 5.84% annual escalation in subsequent contract years. The PUC found that avoided costs for energy were $49.24/MWh, if the project began production in 2013, or $51.23/MWh if the project began production in 2014. The PUC ruled that the avoided energy cost values were to be adopted as levelized values, and would remain constant throughout the QF contract period.

Q. WHAT ARE THE JUHL PROJECTS AND WHAT IS THE HISTORY OF COMMUNICATIONS/NEGOTIATIONS BETWEEN THE PARTIES IN THIS PROCEEDING?

A. The Juhl Energy Projects consist of three 20 MW (nameplate capacity) wind projects located in South Dakota. Juhl has entered into negotiations with NorthWestern, and has or will reach agreement on commercial terms for a PPA agreement, with the exception of the price/avoided cost value. During the negotiation process, NorthWestern has provided a number of different avoided cost projections to Juhl, all of which have been lower than NorthWestern's actual avoided cost, in my opinion. The table below lists the projections provided by NorthWestern at different times throughout the negotiation process.

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	11/24/2015 Letter to Juhl (PDF) McKenzie A. Davis Corporate Paralegal Northwestern Energy	12/9/2015 Letter to Juhl (PDF) McKenzie A. Davis Corporate Paralegal Northwestern Energy	1/20/2016 Email/spreadsheet Bleau LaFave Director Long Term Resources Northwestern Energy
Year	$/MWh	$/MWh	$/MWh
1	$ 18.10	$ 18.11	$ 9.25
2	$ 18.88	$ 18.73	$ 9.81
3	$ 20.90	$ 19.76	$ 10.73
4	$ 22.02	$ 18.83	$ 10.74
5	$ 25.31	$ 20.65	$ 11.47
6	$ 26.95	$ 21.59	$ 12.10
7	$ 28.15	$ 22.28	$ 12.63
8	$ 29.40	$ 22.41	$ 12.72
9	$ 30.93	$ 23.53	$ 13.58
10	$ 32.24	$ 24.02	$ 13.84
11	$ 33.86	$ 24.81	$ 14.11
12	$ 35.39	$ 25.81	$ 14.69
13	$ 37.03	$ 26.16	$ 14.99
14	$ 38.80	$ 26.74	$ 15.31
15	$ 40.66	$ 27.51	$ 15.71
16	$ 42.60	$ 28.41	$ 16.24
17	$ 44.55	$ 29.29	$ 16.68
18	$ 46.55	$ 30.07	$ 16.82
19	$ 48.72	$ 30.51	$ 16.81
20	$ 50.78	$ 31.00	$ 16.93
NWE Estimate	N/A (Above rates only)	N/A (Above rates only)	$11.67 (Levelized)
	$31.02 Aprox. Levelized	$21.94 Aprox. Levelized	$11.67

	1/20/2016 Email/spreadsheet Bleau LaFave Director Long Term Resources Northwestern Energy	2/2/2016 Email/spreadsheet Bleau LaFave Director Long Term Resources Northwestern Energy	4/5/2016 Email/spreadsheet Bleau LaFave Director Long Term Resources Northwestern Energy
Year	$/MWh	$/MWh	$/MWh
1	$ 14.66	$ 18.11	$ 14.99
2	$ 15.22	$ 18.68	$ 15.73
3	$ 16.14	$ 19.59	$ 17.74
4	$ 16.15	$ 19.60	$ 18.87
5	$ 16.88	$ 20.33	$ 20.06
6	$ 17.51	$ 20.96	$ 21.14
7	$ 18.04	$ 21.48	$ 22.06
8	$ 18.13	$ 21.57	$ 24.08
9	$ 18.99	$ 22.43	$ 25.36
10	$ 19.25	$ 22.69	$ 26.24
11	$ 19.52	$ 22.95	$ 27.52
12	$ 20.10	$ 23.54	$ 29.04
13	$ 20.40	$ 23.84	$ 30.45
14	$ 20.72	$ 24.16	$ 31.59
15	$ 21.12	$ 24.55	$ 32.98
16	$ 21.65	$ 25.08	$ 34.55
17	$ 22.09	$ 25.52	$ 36.21
18	$ 22.23	$ 25.66	$ 37.98
19	$ 22.22	$ 25.65	$ 40.03
20	$ 22.34	$ 25.77	$ 41.74
NWE Estimate	$16.61 (Levelized)	N/A (Above rates only)	$24.35 (levelized)
	$16.61	$20.04 Aprox. Levelized	$24.35

As shown in the above table, in the six weeks between November 24, 2015, and January 20, 2016, NorthWestern decreased its avoided cost estimate from $31.02/MWh, to $11.67/MWh, and then a revised value of $16.61/MWh. That is a 50 percent reduction of estimated avoided cost in just a 6 week period. In the subsequent 8 weeks, NorthWestern's estimate of its avoided cost has increased to $24.35/MWh, which is an improvement, but is still well below its actual avoided cost.

Because the NorthWestern proposed avoided cost value was well below apparent market forecasts over a 20-year period, and below what Juhl perceived as NorthWestern's actual avoided cost during that time frame, Juhl retained PMRG to review NorthWestern's methodology, and to also develop an independent projection of avoided cost. PMRG and Juhl participated on two conference calls with NorthWestern to discuss its avoided cost methodology. Subsequently, PMRG identified a number of concerns with the NorthWestern methodology, and provided an overview of those concerns to NorthWestern on an additional conference call. The specific items discussed are detailed in the following section of this testimony.

In response, NorthWestern did make some changes to its avoided cost methodology, and then developed an updated estimate of its avoided cost, applicable to the Juhl projects. NorthWestern provided its updated avoided cost projection on April 1, 2016, at a value of $22.20/MWh.

Juhl Energy believes that a Legally Enforceable Obligation, ("LEO"), has been established, requiring it to sell all of its output from the Project to NorthWestern, and creating a binding obligation on the part of NorthWestern to purchase all of Juhl Energy's output..

Q. CAN YOU DESCRIBE NORTHWESTERNS AVOIDED COST ESTIMATES FOR THE JUHL PROJECTS?

A. NorthWestern estimated Juhl Energy's long-term avoided cost as follows:

Table 2 – NorthWestern Energy Proposed Juhl Energy Levelized Avoided Cost ($/MWh)

Variable	Initial Estimate December, 2015 ($/MWh)	Revised Estimate April, 2016 ($/MWh)
Energy Average Avoided Cost	$19.75	$24.62
Renewable Energy Credit Value	$0.37	$0.47
Regulation	($0.27)	($0.33)
Transmission Network Upgrades	($3.24)	($2.56)
Avoided Cost (Offer)	**$16.61**	**$22.20**

As shown in Table 2, NorthWestern proposed a series of "adjustments" to avoided cost, to reflect Renewable Energy Credit value, and proposed deductions for Regulation Cost and for Transmission Network Upgrades. The reductions proposed by NorthWestern total to almost 20 percent of the original energy avoided cost estimate, due primarily to a large deduction for transmission network upgrade costs.

The most substantial adjustment to avoided cost proposed by NorthWestern, is a $3.24/MWh deduction to reflect the cost of Transmission Network Upgrades. PMRG believes this proposed adjustment is in violation of non-discrimination policies established by the Federal Energy Regulatory Commission (FERC), and should not be included in determining Juhl Energy's avoided cost. FERC transmission policy is very clear, in assigning the cost of network upgrades to project developers during the development stage, but then requiring the transmission provider to refund those costs, with interest, at the time a project achieves commercial operation. NorthWestern's proposed adjustment for those costs is counter to FERC policy, and unfairly discriminates against QF resources. PMRG has not seen this adjustment proposed or adopted in any other avoided cost proceeding, and believes this adjustment should not be included in determination of avoided cost for Juhl Energy.

Q. WHY DO YOU BELIEVE NORTHWESTERN'S PROPOSED ADJUSTMENT FOR TRANSMISSION NETWORK UPGRADE COSTS IS DISCRIMINATORY?

A. I believe the proposed adjustment is a violation of FERC transmission interconnection policy, and unfairly discriminates against QF resources. For example, if a merchant generator sought interconnection on the NorthWestern transmission system, it would be required to pay for network upgrade costs during the development stage, but when it achieves commercial operation, those costs would be refunded by NorthWestern. As NorthWestern would have no contractual operation to purchase power from that merchant resource, it would also have no opportunity to try and recover network upgrade costs. So under NorthWestern's proposed avoided cost adjustment, a QF would be required to pay for network upgrade costs, but a merchant plant would not. That is the definition of discriminatory pricing treatment, and highlights how NorthWestern's proposed adjustment is discriminatory and in violation of PURPA.

Q. WHAT IS THE METHODOLOGY REPORTEDLY EMPLOYED BY NORTHWESTERN TO PRODUCE ITS AVOIDED COST ESTIMATES FOR THE JUHL PROJECTS?

A. The following summary of NorthWestern's avoided cost methodology is based upon the description of the approach provided by NorthWestern via conference calls with Juhl Energy and me. The description I provide below is also based upon review of public documents filed by NorthWestern in other jurisdictions.

NorthWestern typically describes its avoided cost approach as a differential revenue requirements method, where it completes a power system simulation using the PowerSimm model. NorthWestern states that it simulated operation of its power system with and without inclusion of the Juhl Energy project. NorthWestern then states that it examined changes in the net energy balance on its system, and assigned value to output of Juhl Energy. As described, in assigning value to Juhl Energy energy production, NorthWestern differentiated between time periods when its system energy balance was in surplus or deficit. As described, the following differentiation was applied:

For periods when Juhl Energy produces and delivers energy when NorthWestern's supply portfolio is short (i.e., when generation is less than load), Juhl Energy generation is assigned the market purchase price for electricity that NorthWestern would otherwise have purchased.

For periods when the project produces and delivers energy when NorthWestern's supply portfolio is long (i.e., when generation is greater than load), if NorthWestern's generating resources can reduce dispatch levels, then Juhl Energy generation is assigned a value equal to the variable cost of the unit being backed down . If NorthWestern generation is already dispatched at minimum levels, then energy produced by Juhl resources is valued at zero.

NorthWestern describes its avoided cost approach as modeling the impact of Juhl Energy production upon the NorthWestern power system, on an hourly basis, and examining the differential with and without Juhl Energy in estimating avoided cost.

The PowerSimm model employed by NorthWestern in determining avoided cost relies upon externally produced forecasts of fuel prices, including natural gas prices, forecasts of electricity demand on the NorthWestern system, and forecasts of available generating capacity and operating characteristics for NorthWestern power plants. Most importantly, the model also relies upon an externally produced forecast of electricity prices. The inner workings of the model are not at all transparent. This aspect critically limits the ability to analyze NorthWestern's avoided cost methodology, and its specific projections for Juhl Energy.

Q. WHAT CONCERNS, IF ANY, DO YOU HAVE OF THE METHODOLOGY EMPLOYED BY NORTHWESTERN TO CREATE AN AVOIDED COST ESTIMATE FOR THE JUHL PROJECTS?

A. As described on conference calls and in workpapers provided to Juhl, NorthWestern describes a number of data assumptions it made that underlie its avoided cost methodology and projections. In reviewing the fundamental data assumptions used by NorthWestern, there are a number of areas where the approach, and specific assumptions chosen, tend to reduce or suppress estimated avoided cost levels. They key areas requiring adjustment are detailed below.

Q. WHAT AREAS OF CONCERN HAVE YOU IDENTIFIED?

A. First, what NorthWestern describes as a Differential Revenue Requirements Method is in reality not a Differential Revenue Requirements Method as that method has been traditionally understood. While NorthWestern describes its approach as an application of the Differential Revenue Requirements Method, and states that it is the most accurate way to measure avoided cost, the actual application of its approach is quite different from a Differential Revenue Requirement Method. Typically, application of the Differential Revenue Requirements (DRR) avoided cost approach normally involves running detailed, fundamentally based production cost simulation models, both with and without the QF resource on the host utility system. The approach is also sometimes referred to as "QF-In/QF-Out." It is true that the traditional DRR avoided cost approach has been referred to as the most accurate way to measure avoided cost.

The reason that the DRR avoided cost approach is used, and sometimes preferred by state commissions, is because it captures the changes in system dispatch and in underlying cost to produce energy, on a system-wide basis, when a QF resource is introduced onto a power system. The approach was adopted in cases where large amounts of QF resources were being developed on target utility systems, or where the types of QF resources being developed had significantly different operating and cost profiles. In cases such as that, capturing the interaction with other generation on the system can have important implications for measuring avoided cost and for determining the value a particular QF brings to a host utility. An example of a cases where use of this approach could be important would be in assessing avoided cost for a large cogeneration facility, where the efficiency of the underlying resource brings energy cost savings to the host utility, but where the must-run energy production profile of the resource, and associated must-take energy purchases from the host utility, have implications for overall costs, and also for dispatch of other generation on the system. The key focus of the DRR method is to measure the changes in power system production costs in a more precise way.

Q. HOW DOES NORTHWESTERN'S AVOIDED COST METHODOLOGY DIFFER FROM A DRR METHODOLOGY?

A. In NorthWestern's avoided cost approach, while the utility states that it conducted QF-In/QF-Out simulations, it did not use the PowerSimm model to measure changes in production cost with and without the Juhl Energy projects. In contrast, NorthWestern apparently completed PowerSimm simulations with and without Juhl Energy, tabulated results on a monthly basis, and then external to the simulation, applied a combination of forecast monthly energy prices, and/or production cost estimates for its existing generation, or zero to the monthly forecast production of Juhl Energy. NorthWestern limited its use of the PowerSimm model only to estimate whether its system would be in a net purchase or net sale position, on a monthly basis, segmented by High Load (On-Peak) and Low Load (Off-Peak) periods. NorthWestern also used the PowerSimm model to develop long-term market price projections in SPP, but the approach taken in that area is not transparent.

By not using the PowerSimm simulations to assess production costs differences on its system, with and without Juhl Energy, NorthWestern departs fundamentally from the DRR approach. It's not clear why NorthWestern does not evaluate avoided cost for Juhl Energy, or the net short/sales position on its system on an hourly basis, which is the primary intent of a DRR approach. Instead, NorthWestern rolls up hourly results to calculate net purchase/sales position monthly, on-peak and off-peak, and then applies forecast prices in SPP, or in some instances, either the production cost of generation or assigns a zero value to that generation.

Q. HAVE YOU SEEN DATA SUGGESTING THAT NORTHWESTERN IS ACTIVE IN BOTH PURCHASING AND SELLING ENERGY IN THE WHOLEALE MARKET?

A. Yes. NorthWestern consistently purchases and sells energy in the wholesale power market, both in its Montana operations and in its South Dakota operations. Table 3 below shows NorthWestern's market purchase and sale history, as reported through the FERC Form 1. These data were extracted by PMRG from the Energy Velocity datasource. As shown, NorthWestern routinely and consistently engages in both power sales and purchase activity in the wholesale power market. These data show that NorthWestern routinely engages in both wholesale purchase and sale transactions. This is important because while NorthWestern's avoided cost methodology assumes when it is in a net sales position (generation is greater than load), it would back down its existing generation in order to accommodate energy production from the Juhl projects, and would assign something less than market price to the Juhl production. As discussed earlier, this violates economic dispatch principles. The data in Table 3 show that NorthWestern routinely engages in wholesale power sales, and operates its system differently from what it assumes in its avoided cost methodology.

Table 3 – NorthWestern Energy Purchase and Sales Data

	2010	2011	2012	2013	2014	2015
Power Purchases (MWh)	6,790,265	5,936,248	5,971,881	6,762,934	7,013,369	4,752,672
Energy Charges ($)	$299,843,946	$255,317,849	$252,484,353	$311,119,417	$304,822,900	$231,825,119
Demand Charges ($)	$19,457,729	$9,899,498	$12,917,081	$10,441,580	$11,166,832	$12,527,973
Total Charges ($)	$319,262,816	$265,180,449	$265,206,353	$321,523,916	$315,957,355	$244,320,023
Energy Charges ($/MWh)	$44.16	$43.01	$42.28	$46.00	$43.46	$48.78
Total Charges ($/MWh)	$47.02	$44.67	$44.41	$47.54	$45.05	$51.41
Power Sales (MWh)	2,446,738	1,398,453	1,429,602	1,965,449	2,425,078	3,522,568
Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Demand Revenue ($)	$0	$0	$0	$0	$0	$0
Total Energy Sales Revenue ($)	$91,021,282	$22,387,196	$22,778,986	$47,864,234	$65,512,720	$84,836,564
Energy Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08
Total Sales Revenue ($/MWh)	$37.20	$16.01	$15.93	$24.35	$27.01	$24.08

Q. WHAT OTHER CONCERNS, IF ANY, DO YOU HAVE REGARDING NORTHWESTERN'S AVOIDED COST METHODOLOGY IN THIS PROCEEDING?

A. As described, NorthWestern states that it uses a forward electricity and natural gas price strip, and building from those price strips, the PowerSimm model develops prices and simulates operation of its system.

NorthWestern has not provided details about the simulation process used by PowerSimm to translate historical prices into a forecast of future or forward power prices. PMRG also reviewed information available on the Ascend Analytics (Ascend) website. Ascend is the developer of the PowerSimm model. In data responses, and phone conversations, NorthWestern revealed that Ascend had been involved in completing the PowerSimm simulations, and that output data from the simulations resides on computer servers in the Ascend offices. The Ascend website refers to use of stochastic modeling, and a mean-reversion algorithm for PowerSimm, but also provides very little detail, and no characterization of how stochastic parameters are derived or used in the model.

To develop my understanding of the NorthWestern PowerSimm simulation, PMRG also reviewed documentation provided with NorthWestern's 2013 Electricity Supply Resource Procurement Plan filed in Montana. In supporting documents related to that plan, NorthWestern refers to stochastic modeling of natural gas prices, power prices, hydro production, electricity demand, renewable production, and generator outages. Based on the discussion contained in supporting documents submitted to the Montana Public Service Commission, the inference is that NorthWestern followed a similar approach in developing its Juhl Energy avoided cost estimates, but with updated input price curves for natural gas and SPP electricity prices.

In its avoided cost analysis provided to Juhl Energy, NorthWestern does not discuss the stochastic nature of the PowerSimm model, and does not provide any information about the algorithms used, the specification of probability distributions and correlation and covariance statistics, or other key input data and algorithms that play a pivotal role in the PowerSimm simulation environment. This is critical information to omit, because the specification of volatility and correlation parameters plays a key role in influencing the dispatch results, and especially the projected power prices.

Q. DID NORTHWESTERN MAKE ANY ADJUSTMENTS TO ITS METHODOLOGY AFTER DISCUSSION WITH PMRG?

A. The NorthWestern avoided cost approach starts with a near-term forward/futures electricity price curve, and applies escalation to translate that curve into long-term projected prices. In NorthWestern's initial avoided cost estimate, it applied a nominal escalation rate of 1.27% in developing its long-term forecast, and pointed to a variable listed in the EIA Annual Energy Outlook, 2015 as the source of the escalator. PMRG reviewed that escalation rate and pointed out to NorthWestern that it reflected both historical and incremental fixed capital cost components, in addition to wholesale energy market components. As such, the escalation used by NorthWestern was more reflective of a fully embedded rate, and not reflective of likely changes in wholesale market energy costs as is necessary to forecast incremental energy prices in the future.

In response to PMRG's review of that escalation rate, NorthWestern revised its methodology to use an escalation rate based on EIA forecast natural gas prices instead. Under NorthWestern's revised projections, power prices are escalated at 4.32% annually.

Q. DID YOU HAVE ANY OTHER CONCERNS ABOUT THE NORTHWESTERN AVOIDED COST ESTIMATE?

A. Yes. NorthWestern did not reflect likely CO_2 emissions regulation impacts, and likely Clean Power Plan (CPP) compliance costs in developing its avoided cost projections. While CPP implementation is currently stayed by the U.S. Supreme Court, the greenhouse gas emissions reductions inherent in CPP remain a highly likely requirement in the U.S. power industry. Virtually all U.S. utility companies include greenhouse gas reduction regulations in the current power supply and integrated resource planning analyses. This includes NorthWestern. NorthWestern has consistently reflected CO2 compliance costs in its resource planning analyses in both its South Dakota and Montana jurisdictions. In recent avoided cost projections developed in Montana, NorthWestern has explicitly reflected CO2 compliance costs in its avoided cost projections, and proposed that inclusion as appropriate if a wind project developer provides Renewable Energy Credits (RECs) from the project to NorthWestern. In its most recent 2014 South Dakota Integrated Resource Plan, NorthWestern explicitly recognizes likely CO2 emissions compliance costs, averaging $21.11/ton over the forecast period. In its justification for purchasing hydro-electric generating assets before the Montana Public Service Commission in 2014, NorthWestern used CO2 emissions compliance costs starting at $21/ton in 2021, and escalating at 5 percent annually. In its recently filed 2015 Electricity Supply Resource Procurement Plan in Montana, NorthWestern used CO2 emissions compliance costs starting at $20/ton in 2022, and increasing to $37/ton by 2037. As such, it is clear that NorthWestern routinely considers CO2 costs in its resource planning decisions, and CO2 emissions compliance costs should be reflected in the projected avoided cost for the Juhl Energy projects.

Q. WHAT CONCERNS, IF ANY, DO YOU HAVE ABOUT POWERSIMM AS IT IS EMPLOYED BY NORTHWESTERN IN THIS PROCEEDING?

A. As discussed above, NorthWestern utilized the PowerSimm simulation model to develop its forecasted electricity prices in SPP, and its resulting avoided cost for Juhl Energy. The PowerSimm model relies upon near-term forward natural gas and electricity prices, and statistical relationships between fundamental variables, to develop long-term stochastic forecasts of natural gas and power prices, and of NorthWestern system operations. While NorthWestern provides no discussion of its stochastic modeling, or specification of the statistical parameters used, presumably statistical parameters were developed using historical data on fuel prices, electricity prices, electricity demand, hydro production, wind production, generator outages, and other relevant variables.

Statistical relationships are only valid in forecasting if the underlying processes that are being modeled remain stable and unchanging. If the processes are undergoing structural change, then results from statistical modeling are invalid and inaccurate. In the current fuel and power markets, the underlying processes that form prices are rarely stable and unchanging. To the contrary, those price formation processes are fundamentally based, and are undergoing substantial structural transformation. Moreover, that transformation will continue for the foreseeable future. There are a variety of factors contributing to structural change in the fuel and power markets:

- The advent of shale gas production has fundamentally changed the supply dynamics of natural gas, the cost of production/extraction, and is also fundamentally changing natural gas basis differentials compared to historical price levels
- U.S. EPA environmental policies to reduce hazardous air pollutants, regional haze, Nitrogen Oxide, Sulfur Dioxide, and Carbon Dioxide, are having a significant impact on the electric generation supply mix, and are causing the retrofit and/or retirement of a substantial number of coal-fueled generators.
- The wide-scale penetration of wind and solar resources in the Upper Midwest, and throughout the country, are further altering the economics of power generation, the underlying composition of the supply mix, and the operation of fossil resources.
- Lower natural gas prices, more economic construction costs, and lower emissions from natural gas-fueled generation relative to coal-fueled resources, are all driving a substantial increase in the demand for natural gas for use in electricity generation. In virtually all long-term projections, natural gas use for electricity generation is the largest projected component of demand growth for that fuel.

These factors all point to increased demand and prices for natural gas, which will further increase the correlation between natural gas and electricity prices in SPP but will also alter the underlying statistical relationships between fuel and electricity prices in the region, and between those prices and other key fundamental variables. A statistical model such as PowerSimm is not able to fully or accurately capture the fundamental changes occurring in the fuel and power markets, due to its reliance upon historical statistical relationships. Instead, it is necessary to utilize a fundamental simulation model to fully capture the changing dynamics of the industry. For this reason, virtually all major consulting firms that develop long-term fuel and power price forecasts, utilize structural simulation models, for developing forecasted natural gas and electricity prices. This includes firms such as Ventyx, Navigant Consulting, ICF, Pace Global, and Black & Veatch. Given the strong growth in natural gas demand anticipated due to environmental regulation affecting the power industry, using a statistically based model such as PowerSimm, is likely to understate the underlying fundamental natural gas and energy price levels in the market.

Q. IN LIGHT OF THE FOREGOING ANALYSIS, DO YOU FIND NORTHWESTERN'S AVOIDED COST ESTIMATE FOR JUHL ENERGY REASONABLE AND CREDIBLE?

A. No. Given the lack of transparency in the PowerSimm model and the statistical parameters applied by it, and the relative lack of clarity about what the stochastic modeling utilized by NorthWestern purports to address, I believe a simpler and more repeatable methodology for new large QFs like Juhl Energy is in order.

Q. WHAT ALTERNATIVE FORECAST DO YOU PROPOSE TO UTILIZE IN THIS PROCEEDING IN ORDER TO DEVELOP AVOIDED COST RATES FOR JUHL ENERGY?

A. Given the assessment above, PMRG believes that the NorthWestern proposed avoided cost for Juhl Energy is lower than its actual avoided cost. This is due to the methodology employed by NorthWestern, and due to the proposed deductions from avoided cost for transmission network upgrade costs, which should not be included.

To develop a more accurate estimate of NorthWestern's avoided cost, PMRG developed an independent forecast for use in determining avoided cost to be applied to the Juhl Energy projects. The approach taken by PMRG in developing avoided cost projections is summarized as follows:

1. PMRG licensed the PROMOD IV simulation model from Ventyx, and completed a true Differential Revenue Requirement method to develop avoided cost projections
2. PMRG also licensed the Ventyx Advisors data set, which allows replication and use of Ventyx's Advisors Reference Case fuel and electricity price forecast. The Ventyx Reference Case is an independent forecast developed by Ventyx, and is used as the basis for power supply planning decisions throughout the country. The Ventyx Reference case is also used to provide independent electricity price forecasts and valuation estimates in many transactions involving purchase and sale of existing power plants throughout the U.S.
3. The NorthWestern South Dakota Power System was dispatched on an hourly basis, for the 2018-2037 period, both including and excluding the Juhl Energy 60 MW wind projects.
4. The Juhl projects were modeled as three separate 20 MW wind resources.
5. The difference in total production costs (fuel, variable O&M, market purchases and market sales revenue), was divided by Juhl Energy generation, to derive avoided cost projections. This approach is consistent with the PUC's approved avoided cost

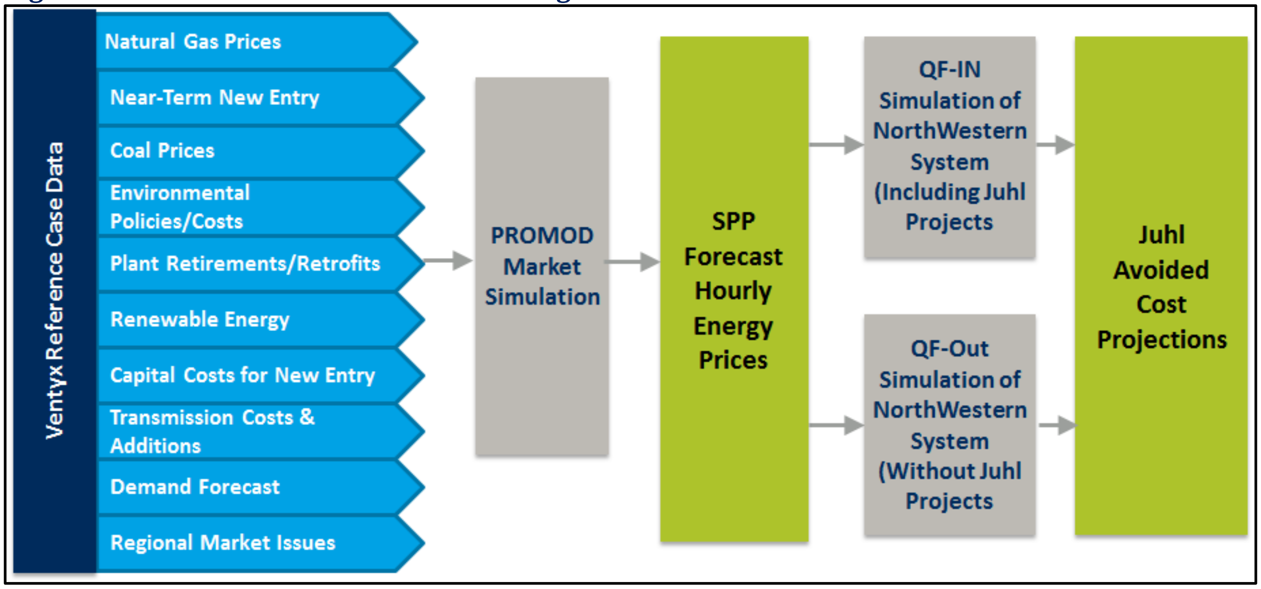
methodology, in examining a utility system's hourly incremental cost as a basis for determining avoided cost.

6. Market purchase and sales were included as dispatch options in the analysis, and occur based on forecast hourly SPP-Dakotas power prices from the Ventyx Reference Case. As such, this is a true Differential Revenue Requirement analysis, and is also consistent with how NorthWestern actually operates its power system in South Dakota.

7. The Ventyx Reference Case does not include carbon costs, or CPP compliance costs. A separate CPP compliance case was also developed, to estimate incremental avoidable costs that will be faced by NorthWestern, due to the Clean Power Plan.

PMRG has developed alternative avoided cost estimates, based on the analyses described above. Figure 1 provides an illustration of the process and data flow underlying PMRG's avoided cost projections. As shown, the process begins with Ventyx Reference Case data assumptions, relies upon the PROMOD IV model to first develop forecast energy prices in SPP, and to then model the NorthWestern South Dakota power system with and without the Juhl Energy projects. Output from those simulations is then used to develop long-term projections of avoided cost on the NorthWestern system.

Figure 1 – PMRG Avoided Cost Process Diagram

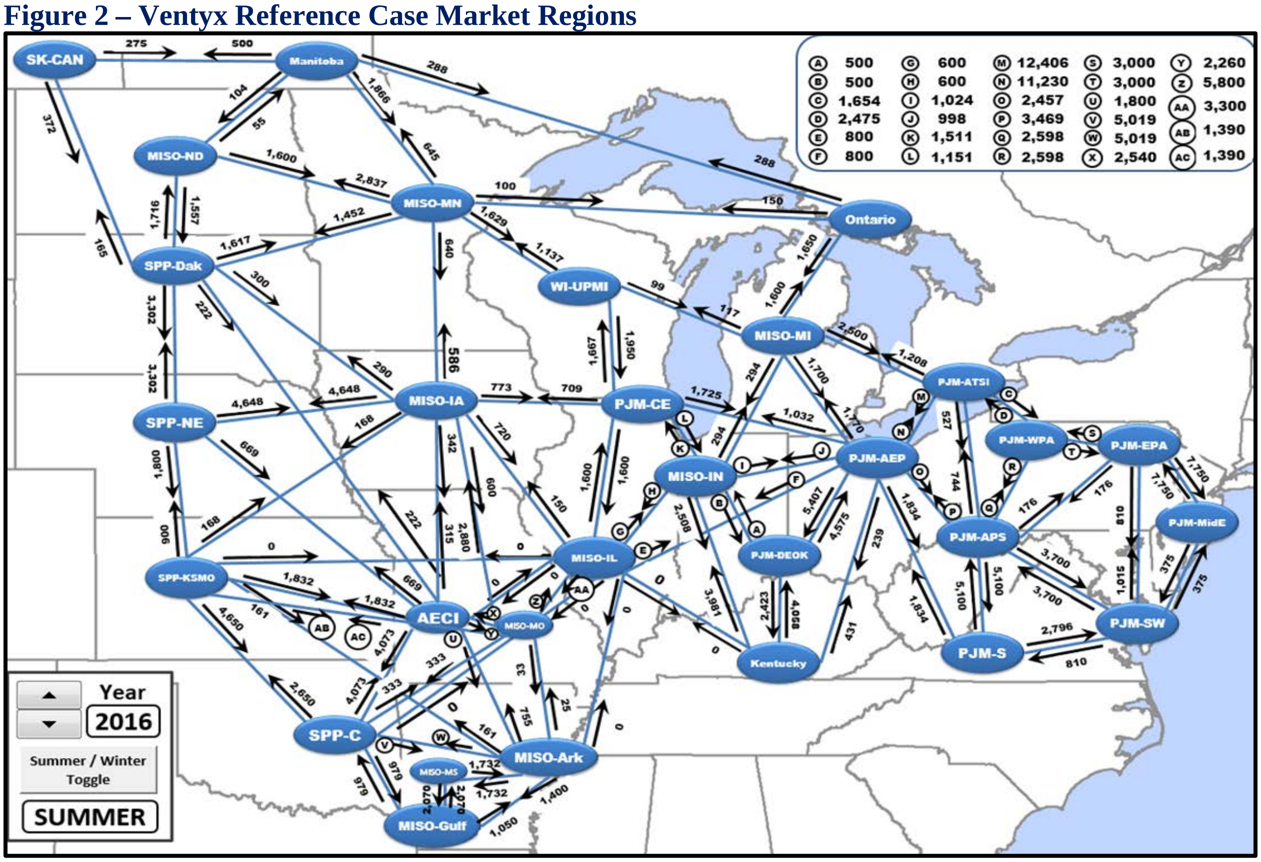


Q. PLEASE DESCRIBE THE VENTYX REFERENCE CASE FORECAST?

A. Ventyx is an ABB company, and is the developer of a number of software and databases widely used in the electricity industry. Ventyx, and its predecessor, Global Energy Decisions has been developing Reference Case power market forecasts since the late 1990s, for all North American power market regions. The Ventyx Reference Case forecast is routinely used throughout the industry in power supply resource planning, and in supporting power plant development activity, financing activity, and purchase and sale of power plant portfolios.

Figure 2 provides an illustration of the power market region topology underlying the Ventyx Reference Case for the Midwest U.S. markets.

Figure 2 – Ventyx Reference Case Market Regions



Source: Ventyx

As shown in Figure 2, the SPP market region is represented as four separate pricing zones in the Ventyx Reference Case, but the underlying fundamental simulation modeling reflects market regions throughout the Midwest and Mid-Atlantic U.S. regions, and Canada. The market simulation configuration used by PMRG also includes the Northeast and Southeast U.S. regions as well. The NorthWestern power system resides within the SPP-Dakota sub-market depicted on Figure 2.

In developing its Reference Case, Ventyx produces a fundamental analysis of the North American electric market twice a year, developed using the PROMOD Electric Market Simulation tool, Velocity Suite data and Horizons Interactive, a market-based, fundamental model of North American power, gas, coal and environmental markets, which accounts for the interdependency of these markets and provides forecasts based on consistent economic assumptions.

Ventyx's Reference Case considers current and projected new generating resources; transmission limits and losses; operations and seam issues in neighboring markets; and hourly loads. It includes a fundamental base forecast of Market Clearing Prices, which are comprised of hourly, monthly and annual prices for the 25 year study period.

In completing this analysis for Juhl Energy, PMRG elected to rely upon the Ventyx Reference Case because it is a well-respected, independent view of North American energy markets and forecast fuel and power prices. The forecast is widely used in the industry, and was not specifically prepared on behalf of Juhl. From PMRG's perspective, use of the Ventyx Reference Case allowed it to develop an unbiased, independent forecast of avoided cost on the NorthWestern system.

Q. PLEASE DESCRIBE FUNDAMENTAL INPUT DATA UNDERLYING THE VENTYX REFERENCE CASE?

A. In developing its Reference Case, Ventyx develops detailed and integrated fundamental input data assumptions concerning supply and demand in the fuel and power markets. The assumptions are used in Ventyx's fuel model and in the PROMOD model to develop fundamental prices for key input variables such as natural gas and coal prices, and for emissions prices. The fuel and emissions prices serve as key input variables for generators. Table 4 describes key considerations.

Table 4 – Ventyx Approach in Developing Fuel and Power Prices

Price Series	Description of Approach
Natural Gas Prices	Considers production cost by basins, transportation network to liquid market centers, and tariffs to the market areas
Coal Prices	Considers production cost curves by mine, transportation network to the plants, and individual plant constraints on heat input and SO2 content
Emissions Prices	Considers current regulatory caps on CO2, SO2 and NOX, existing unit environmental controls and emission rates, and options for retrofits or retirement
Renewable Energy Credit Prices	Considers state RPS demand for renewables, current existing renewable generation, cost curves and characteristics of new renewable capacity, and regional potential
Capacity Prices	Considers cost curves for new generation, reserve margin requirements, economic retirement options, and capacity market areas
Energy Prices	Considers detailed unit characteristics incorporating all forecasts presented above, hourly dispatch of units versus demand, scarcity adders at tighter reserve margins, and electric transmission network

Source: Ventyx

Table 5 below lists the electricity demand forecast for the Midwest regions, built into the Ventyx Reference Case assumptions. Ventyx relies upon demand forecasts submitted by load-serving entities and reported to FERC through the Form 715 filings as a key input for developing demand forecasts, supplemented by demand forecasts prepared by regional ISO entities such as SPP and MISO. In modeling the NorthWestern system, PMRG relied upon the demand forecast presented by NorthWestern in its 2014 South Dakota Resource Plan.

Table 5 – Midwest Electricity Demand Forecast

Year	Manitoba		MISO		MISO-South		PJM		SaskPower		SPP	
	Peak Load (MW)	Total Energy (GWh)	Peak Load (MW)	Total Energy (GWh)	Peak Load (MW)	Total Energy (GWh)	Peak Load (MW)	Total Energy (GWh)	Peak Load (MW)	Total Energy (GWh)	Peak Load (MW)	Total Energy (GWh)
2016	4,623	26,442	96,493	512,130	30,493	165,863	164,434	829,073	3,821	25,160	53,858	266,321
2017	4,686	26,724	97,642	518,143	30,828	168,041	166,386	837,634	3,961	26,163	54,669	270,367
2018	4,659	26,924	98,454	522,497	31,217	170,168	167,743	846,532	4,033	26,734	55,149	273,176
2019	4,710	27,158	99,198	526,448	31,644	172,508	169,193	852,988	4,067	26,987	55,929	277,175
2020	4,782	27,561	99,896	530,136	32,025	174,376	170,923	863,417	4,110	27,396	56,691	281,302
2021	4,889	28,073	100,313	532,302	32,182	175,103	172,259	869,425	4,197	27,955	57,525	285,493
2022	4,985	28,611	100,896	535,345	32,413	176,310	173,886	878,200	4,267	28,480	58,368	289,704
2023	5,064	29,086	101,486	538,449	32,638	177,918	175,438	886,178	4,307	28,713	59,263	294,238
2024	5,134	29,488	102,243	542,528	33,068	180,278	176,695	896,015	4,361	29,072	60,048	298,425
2025	5,205	29,896	102,722	545,079	33,290	181,485	178,230	901,167	4,415	29,436	60,811	302,509
2026	5,277	30,310	103,207	547,653	33,552	182,701	179,832	908,745	4,471	29,804	61,596	306,698
2027	5,350	30,730	103,703	550,251	33,803	183,925	181,092	916,216	4,526	30,176	62,402	311,000
2028	5,424	31,155	104,181	552,873	34,048	185,157	182,536	926,501	4,583	30,554	63,257	315,419
2029	5,499	31,586	104,712	555,518	34,193	186,398	183,817	932,214	4,640	30,936	64,040	319,611
2030	5,575	32,023	105,203	558,188	34,418	187,648	185,420	939,588	4,698	31,323	64,847	323,893
2031	5,652	32,466	105,712	560,882	34,650	188,907	186,670	945,907	4,757	31,714	65,675	328,279
2032	5,731	32,915	106,229	563,600	34,949	190,174	187,933	952,273	4,817	32,111	66,518	332,770
2033	5,810	33,371	106,753	566,343	35,194	191,450	189,204	958,686	4,877	32,512	67,381	337,348
2034	5,890	33,832	107,290	569,111	35,354	192,735	190,491	965,147	4,938	32,919	68,296	342,035
2035	5,972	34,300	107,810	571,904	35,591	194,029	191,773	971,656	5,000	33,330	69,198	346,837
2036	6,054	34,775	108,329	574,721	35,826	195,332	193,063	978,214	5,062	33,747	70,113	351,751
2037	6,138	35,256	108,862	577,565	36,109	196,644	194,371	984,820	5,125	34,169	71,056	356,786
2038	6,223	35,744	109,414	580,433	36,379	197,965	195,691	991,476	5,190	34,596	72,030	361,945
2039	6,309	36,239	109,964	583,328	36,634	199,296	197,019	998,181	5,254	35,029	73,029	367,233
2040	6,397	36,740	110,521	586,248	36,802	200,636	198,363	1,004,936	5,320	35,467	74,070	372,653
Growth Rate	1.36%	1.38%	0.57%	0.56%	0.79%	0.80%	0.78%	0.80%	1.39%	1.44%	1.34%	1.41%

Source: Ventyx

The Ventyx Reference Case assumptions reflect announced power plant retirements in the region, driven largely by compliance activities related to the EPA MATS regulation, and due to unit operating lives, and due to economic screening analysis completed by Ventyx. The assumptions also reflect new power plants currently under construction or active development, renewable energy expansion anticipated to comply with Renewable Portfolio Standard requirements, and generic new entry thermal units needed to maintain reserve margin targets over the forecast period.

Table 6 lists generation capacity retirements in SPP during the forecast period, under Ventyx Reference Case assumptions. Table 7 lists a load and resource balance for the SPP region as a whole, reflecting forecast demand growth, and installed generation capacity by type. Table 7 also lists planning reserve margin levels in the SPP region during the forecast period.

Table 6 – SPP Generation Retirements (MW)

Year	SPP-C	SPP-Dakota	SPP-KSMO	SPP-NE	SPP Total
2016	1,114	12	493	40	1,659
2017	490	16	51	29	586
2018	305	21	1,431	195	1,952
2019	3	6	187	7	203
2020	124	2	49	355	530
2021	5	1	418	167	591
2022	247		262	348	857
2023	67	3	451	8	529
2024	97	7	346	87	537
2025	212		461	1	674
2026	489		260	22	771
2027	248	233	147		628
2028			210	7	217
2029	138		34	1	173
2030	418		356		774
2031	114		55	172	341
2032	373		225	687	1,285
2033	652		120	957	1,729
2034	239		313		552
2035			161	109	270
2036	477	2	150	7	636
2037	60		32	136	228
Total	**5,872**	**303**	**6,212**	**3,335**	**15,722**

Source: Ventyx

Table 7 – SPP Load & Resource Balance

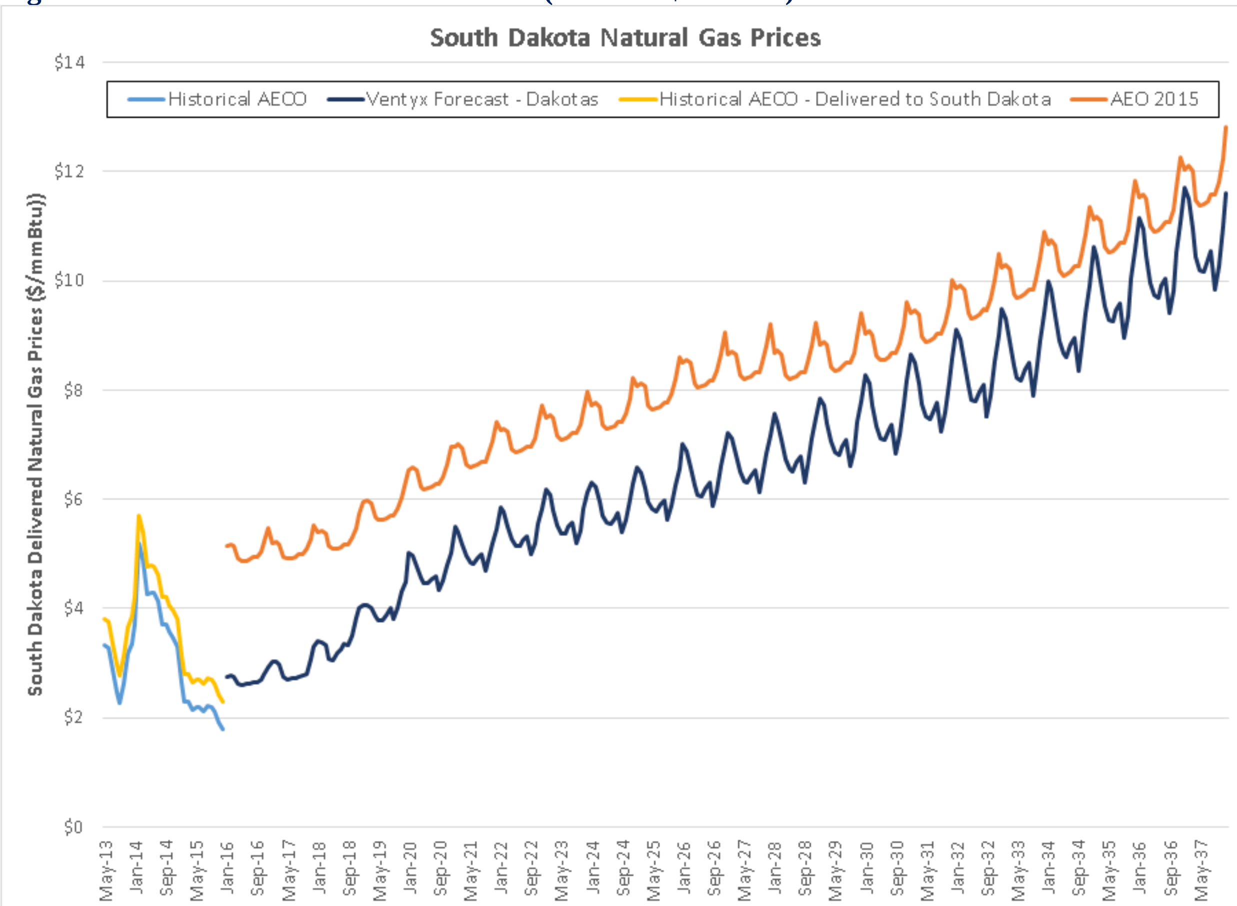
Year	Coal (MW)	Gas (MW)	Fuel Oil (MW)	Nuclear (MW)	Hydro (MW)	Renewable & Other (MW)	Total Capacity (MW)	Net Peak Load (MW)	Reserve Margin (%)
2016	26,469	29,601	1,626	2,419	5,299	4,582	69,997	51,926	35%
2017	25,359	29,569	1,602	2,419	5,299	4,871	69,120	52,700	31%
2018	25,359	29,504	1,579	2,419	5,299	4,906	69,066	53,152	30%
2019	23,872	29,192	1,519	2,419	5,299	4,951	67,252	53,908	25%
2020	23,317	29,663	1,511	2,419	5,299	5,005	67,214	54,649	23%
2021	23,317	29,620	1,483	2,419	5,299	5,081	67,219	55,459	21%
2022	23,275	29,740	1,335	2,419	5,299	5,381	67,449	56,277	20%
2023	23,233	29,616	1,099	2,419	5,299	5,426	67,092	57,129	17%
2024	23,233	29,615	1,063	2,419	5,299	5,426	67,054	57,891	16%
2025	22,716	30,979	893	2,419	5,299	5,456	67,762	58,629	16%
2026	22,716	31,929	738	2,419	5,299	5,456	68,557	59,387	15%
2027	22,716	32,652	578	2,419	5,299	5,456	69,120	60,164	15%
2028	22,716	33,520	400	2,419	5,299	5,456	69,809	60,963	15%
2029	22,716	34,304	400	2,419	5,299	5,456	70,593	61,730	14%
2030	22,716	35,284	389	2,419	5,299	5,456	71,563	62,516	14%
2031	22,716	36,273	379	2,419	5,299	5,456	72,542	63,320	15%
2032	22,607	37,256	376	2,419	5,299	5,456	73,412	64,138	14%
2033	22,607	38,427	365	1,941	5,299	5,456	74,094	64,975	14%
2034	22,498	39,996	365	1,175	5,299	5,456	74,788	65,831	14%
2035	22,390	41,526	362	1,175	5,299	5,456	76,208	66,707	14%
2036	22,390	42,560	354	1,175	5,299	5,456	77,234	67,602	14%
2037	22,261	43,892	351	1,175	5,299	5,456	78,434	68,516	14%

In Table 7, load is shown on a net peak basis, with interruptible demand subtracted from forecast peak demand levels.

Q. PLEASE DESCRIBE THE NATURAL GAS PRICE FORECAST UNDERLYING THE VENTYX REFERENCE CASE?

A. Forecast natural gas prices play a key role in developing long-term energy price forecasts. As shown above in Table 7, natural gas fueled capacity is projected to increase substantially over the period, and as a result, SPP energy prices will become increasingly influenced by the underlying natural gas prices borne by generators. Figure 3 illustrates a natural gas price forecast for key natural gas pricing points under the Ventyx Reference Case, and also lists the AEO 2015 natural gas price forecast, as point of reference.

Figure 3 – SPP Natural Gas Price Forecast (Nominal $/mmBtu)



Nominal escalation in AEO 2015 for natural gas prices, averages 4.2%. The Ventyx Natural Gas Price Forecast is within the range of most fundamental price forecasting services. Given projected growth in natural gas demand, primarily driven by increased demand for natural gas for electricity generation, and given expected production cost increases for shale and conventional natural gas extraction, virtually all fundamentally derived natural gas price forecasts anticipate robust growth in natural gas prices that exceeds the general rate of inflation.

Historical energy prices in the SPP North area averaged $44.52/MWh in 2013, $27.35/MWh in 2014, and $19.66 in 2015. During the last three years, oil and natural gas prices have declined due to abundant supply expansion of shale gas in the U.S., including in the North Dakota area.

As shown above in Figure 3, natural gas prices are projected to remain relatively flat through 2017, and to then increase rapidly beginning in 2018. The increase in projected natural gas prices is driven by anticipated demand growth as substantial amounts of coal generation retires due to the EPA MATS regulation, as natural gas fueled generation takes a more prominent role throughout the country. Natural gas demand continues to drive real price increases in natural gas, as CPP compliance further increases the reliance upon natural gas-fueled generation, and as shale gas extraction costs increase. The higher natural gas prices lead to corresponding increases in projected electric energy prices. Table 8 lists the forecast SPP Dakotas region energy prices under the Ventyx Reference Case. For ease of comparison, the SPP price projections developed by NorthWestern are also shown.

Table 8 – SPP Forecast Energy Prices (Nominal $/MWh)

Year	Ventyx Reference Case - SPP Dakotas	NorthWestern South Dakota (12/2015)	NorthWestern South Dakota - Revised (4/2016)
2016	$26.04	$19.63	$20.57
2017	$27.66	$21.01	$21.27
2018	$29.02	$21.49	$22.19
2019	$33.54	$21.77	$23.15
2020	$36.40	$22.04	$24.15
2021	$39.30	$22.32	$25.19
2022	$41.98	$22.61	$26.28
2023	$44.33	$22.90	$27.41
2024	$46.14	$23.19	$28.60
2025	$47.99	$23.48	$29.83
2026	$50.54	$23.78	$31.12
2027	$52.95	$24.08	$32.46
2028	$55.31	$24.39	$33.86
2029	$57.23	$24.70	$35.33
2030	$59.68	$25.01	$36.85
2031	$61.90	$25.33	$38.44
2032	$64.03	$25.65	$40.10
2033	$67.23	$25.98	$41.83
2034	$72.37	$26.31	$43.64

Year	Ventyx Reference Case - SPP Dakotas	NorthWestern South Dakota (12/2015)	NorthWestern South Dakota - Revised (4/2016)
2035	$76.23	$26.64	$45.52
2036	$79.05	$26.98	$47.49
2037	$82.21	$27.32	$49.54

Q. PLEASE DESCRIBE THE NATURAL GAS PRICE FORECAST UNDERLYING THE VENTYX REFERENCE CASE?

A. Based on the Ventyx Reference Case hourly energy price forecast, completed detailed hourly simulations of the NorthWestern South Dakota power system with and without inclusion of the Juhl Energy projects. All other existing resources owned or under control of NorthWestern were used in the simulation. During hours when the NorthWestern system requires additional energy, the simulation assigns incremental costs for that energy based on forecast SPP market prices. During hours when the NorthWestern system is long on energy, the simulation allows the excess to be sold into the SPP market based again on forecast hourly SPP market prices. This is common and industry accepted best practice for completing power market simulations. It is also how NorthWestern operates, or should operate its power system on a daily basis.

The results of PMRG's Differential Revenue Requirement analysis are summarized in Table 9.

Table 9 – PMRG Differential Revenue Requirement Avoided Cost Estimate

Year	Juhl Project Generation (MWh)	SPP LMP ($/MWh)	QF-In/QF-Out NorthWestern Energy Change in Production Cost - Net of Sales ($000)	Avoided Cost Savings Production Cost - Net of Sales ($/MWh)	Juhl Value - Avoided Cost Savings - SPP LMP Based Estimate	Juhl Value - NorthWestern Production Cost Net of Sales ($MWh)
2018	273,052	$29.02	-$8,046	-$29.47	-$7,923,877	-$8,045,746
2019	273,052	$33.54	-$8,788	-$32.18	-$9,159,001	-$8,787,944
2020	273,052	$36.40	-$9,508	-$34.82	-$9,939,181	-$9,507,863
2021	273,052	$39.30	-$10,186	-$37.31	-$10,730,080	-$10,186,225
2022	273,052	$41.98	-$10,621	-$38.90	-$11,462,273	-$10,621,408
2023	273,052	$44.33	-$11,356	-$41.59	-$12,105,320	-$11,355,914
2024	273,052	$46.14	-$11,832	-$43.33	-$12,597,749	-$11,831,927
2025	273,052	$47.99	-$12,437	-$45.55	-$13,104,871	-$12,437,155
2026	273,052	$50.54	-$12,923	-$47.33	-$13,801,094	-$12,922,982
2027	273,052	$52.95	-$13,591	-$49.77	-$14,459,322	-$13,590,600
2028	273,052	$55.31	-$14,096	-$51.62	-$15,101,627	-$14,095,924
2029	273,052	$57.23	-$14,916	-$54.63	-$15,626,196	-$14,915,535
2030	273,052	$59.68	-$15,461	-$56.62	-$16,295,586	-$15,461,196
2031	273,052	$61.90	-$16,311	-$59.73	-$16,900,611	-$16,310,668
2032	273,052	$64.03	-$17,708	-$64.85	-$17,483,285	-$17,707,758
2033	273,052	$67.23	-$18,756	-$68.69	-$18,356,094	-$18,755,837
2034	273,052	$72.37	-$19,530	-$71.53	-$19,760,478	-$19,530,056
2035	273,052	$76.23	-$20,569	-$75.33	-$20,813,752	-$20,569,064
2036	273,052	$79.05	-$22,028	-$80.67	-$21,586,090	-$22,027,982
2037	273,052	$82.21	-$22,012	-$80.61	-$22,448,269	-$22,011,996
Levelized Avoided Cost - NPV @7.24% ($/MWh)			($134,269)		**$49.07**	**$47.29**

As shown in Table 9, based on the Ventyx Reference Case assumptions and resulting power price forecast, PMRG's estimated levelized avoided cost for the Juhl projects is $47.29/MWh, based on application of the differential revenue requirement method. The Juhl projects are projected to reduce net production costs for NorthWestern by $134.3 million NPV over the 2018 to 2037 time period.

The DRR projection is slightly lower than avoided cost projections based on straight application of the SPP power prices to the Juhl production. That approach would result in a levelized avoided cost estimate of $49.07/MWh. This highlights a feature of the DRR approach, where interactions with NorthWestern's other assets and the time of day generation patterns of the Juhl projects are more rigorously reflected in the analysis

Q. ARE THERE ADDITIONAL ADJUSTMENTS TO AVOIDED COST THE PUC SHOULD CONSIDER IN THIS PROCEEDING?

A. Yes. As discussed above, the Ventyx Reference Case does not reflect CPP compliance costs associated with anticipated requirements to reduce CO2 emissions in the industry. At the same time, given the CPP rules developed by EPA, and given NorthWestern's approach taken in power supply and resource planning analyses, it is appropriate to reflect a carbon component in the avoided cost for Juhl. This is particularly true given that the Juhl Energy wind projects will produce carbon-free energy, which will help NorthWestern in its CPP compliance activities.

To assess the likely impact of carbon regulation on NorthWestern avoided cost, PMRG developed a high level estimate of the likely impact. Under this approach, the CO2 price forecast recently developed by NorthWestern in its Montana Power Supply study was utilized. PMRG assumed that 50 percent of the carbon cost, expressed on a $/MWh basis, would flow through to energy prices. This is a very conservative assumption, as it effectively assumes that efficient natural gas-fueled resources always set marginal energy prices in SPP, so the carbon pricing component would be reflective of CO2 compliance costs for a natural gas-fueled combined-cycle resource. Table 8 lists the incremental impact of CO2 costs on Juhl avoided cost, using this approach. As shown, inclusion of CO2 compliance costs increases levelized avoided cost by $11.63/MWh.

The avoided cost projections discussed above, as well as the NorthWestern avoided cost estimates, also do not reflect any capacity value for the Juhl Energy wind projects. In its 2014 South Dakota Integrated Resource Plan, NorthWestern identified a need for capacity resources beginning in 2019. As such, it would also be appropriate to assign a capacity value to the avoided cost for Juhl Energy.

PMRG developed an estimated capacity value for Juhl Energy, reflecting a 5% capacity credit assigned to Juhl Energy, and based on the avoided capital cost of a LMS100 simple cycle power plant. That technology represents a likely addition in NorthWestern's next resource plan, given the size of its system, and the addition of renewable resources onto its system since the time it last developed a resource plan. The inclusion of capacity value increases the avoided cost for Juhl Energy by $1.78/MWh. That potential adjustment is also reflected in Table 10.

Table 10 – Potential Adjustments to Levelized Avoided Cost ($/MWh)

Differential Revenue Requirement Levelized Avoided Cost - NPV @7.24% ($/MWh)	**$47.29**
CO2 Compliance Cost Incremental Impact ($/MWh)	$11.63
Adjusted Avoided Cost, with CO2 ($/MW)	**$58.92**
Capacity Value of Juhl Projects	$1.78
Total Levelized Avoided Cost, with CO2 and Capacity Value ($/MWh)	**$60.70**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DATED this 16th day of June 2016

Roger Schiffman

ACKNOWLEDGEMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California County of Yolo)

On June 16, 2016 before me, Landon Christensen, Notary Public

(insert name and title of the officer) personally appeared

Roger Schiffman, who proved to me

on the basis of satisfactory evidence to be the person~~(s)~~ whose name~~(s)~~ is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature~~(s)~~ on the instrument the person~~(s)~~, or the entity upon behalf of which the person~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct. WITNESS my hand and official seal.

Signature ______________________ (Seal)

LANDON CHRISTENSEN
Commission # 2117869
Notary Public - California
Yolo County
My Comm. Expires Jul 27, 2019