BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 255,	)	**CASE NO. 15-00139-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

DIRECT TESTIMONY

of

DAVID G. HORNECK

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2014 Base Fuel	Fuel and purchased power costs used to develop the current base fuel factor approved in Case No. 12-00350-UT
2016 Base Fuel	Fuel and purchased power costs used to develop the Test Year base fuel factor
Calpine	Calpine Energy Services L.P.
CSAPR	Cross State Air Pollution Rule
GWh	Gigawatt-hour
MW	Megawatt
MWh	Megawatt-hour
NextEra Energy Resources'	NextEra
NSPM	Northern States Power Company, a Minnesota corporation
Operating Companies	NSPM; Northern States Power Company, a Wisconsin corporation; Public Service Company of Colorado, a Colorado corporation; and SPS
PLEXOS®	PLEXOS® Integrated Energy Model
PPA Wind	Purchases under Purchased Power Agreements with Wind Farms
PPAs	Purchased Power Agreements
QF	Qualifying Facility

Acronym/Defined Term	**Meaning**
QF Wind	Qualifying Facility Purchases from Wind Farms
RECs	Renewable Energy Certificates
RFP	Rate Filing Package
RPS	Renewable Portfolio Standard
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company, a New Mexico corporation
TCR	Transmission Congestion Rights
Test Year	January 1, 2016 through December 31, 2016
TMY	Typical Meteorological Year
VOM	Variable operation and maintenance
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

LIST OF ATTACHMENTS

Attachment	**Description**
DGH-1	Comparison of 2014 Fuel and Purchased Power Costs to 2016 Costs (*Filename:* DGH-1.xlsx)
DGH-2	Workpapers (*See Folder:* Testimony/19 - Horneck/DGH-2)

Case No. 15-00139-UT
Direct Testimony
of
David G. Horneck

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David G. Horneck. My business address is 1800 Larimer St., Denver, Colorado 80202.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company ("SPS"), a New Mexico corporation and wholly-owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a registered holding company that owns several electric and natural gas utility operating companies.[1]

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. ("XES"), the service company subsidiary of Xcel Energy, as Manager Generation Modeling Services.

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[1] Xcel Energy is the parent company of four wholly-owned electric utility operating companies: Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation; Public Service Company of Colorado, a Colorado corporation; and SPS (collectively, "Operating Companies"). Xcel Energy's natural gas transmission pipeline company is WestGas InterState, Inc. Xcel Energy also has two transmission-only operating companies, Xcel Energy Southwest Transmission Company, LLC and Xcel Energy Transmission Development Company, LLC, which are regulated by the Federal Energy Regulatory Commission.

Q. Please briefly outline your responsibilities as Manager Generation Modeling Services.

A. As Manager Generation Modeling Services, I am responsible for managing the modeling of generation assets and purchased power agreements in order to produce production cost forecasts for corporate budgeting purposes and rate case and regulatory filings for the Operating Companies.

Q. Please describe your educational background.

A. I have a Bachelor of Science degree in Nuclear Engineering from the University of Wisconsin – Madison.

Q. Please describe your professional experience.

A. I have 22 years of experience at XES and NSPM in a variety of areas and responsibilities. These include nuclear power engineering, nuclear core design and reactor safety analysis, nuclear fuel procurement, and risk management. I joined the Risk Management – Generation Modeling Services Department in 2001. I began in the group as a Generation Modeling Analyst, was promoted to Senior Generation Modeling Analyst in November 2002, and to my current position as Manager Generation Modeling Services in June 2005.

Q. Have you attended or taken any special courses or seminars relating to public utilities?

A. Yes. I have completed the Utility Finance and Accounting for Financial Professionals seminar.

Q. Have you testified before any regulatory authorities?

A. Yes. I have testified before state utility regulatory authorities in Colorado, Minnesota, and Wisconsin, and have filed testimony with the New Mexico Public Regulation Commission, the Public Utility Commission of Texas, and the Michigan Public Service Commission regarding generation modeling and forecasting of fuel and purchased power expense for SPS and other Xcel Energy Operating Companies.

II. ASSIGNMENT AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is your assignment in this proceeding?

A. I will discuss the reasonableness of the fuel and purchased power costs SPS seeks to recover in this proceeding for the forecasted calendar year 2016 ("Test Year"). In this regard, I will compare fuel and purchased power costs used to develop the Test Year base fuel factor (*i.e.,* "2016 Base Fuel") with the fuel and purchased power costs used to develop the current base fuel factor approved in Case No. 12-00350-UT[2] (*i.e.,* "2014 Base Fuel"). Additionally, I co-sponsor Schedules H-2, H-3, and P-12 in SPS's Rate Filing Package ("RFP").

Q. Please provide a summary of the conclusions and recommendations in your testimony.

A. Overall, SPS's Test Year fuel and purchased power costs are projected to decrease by $124.3 million, or 14.1%, as compared to the costs reflected in the 2014 Base Fuel factor. SPS's projected fuel and purchased power costs for 2016 account for known and forecasted changes in fuel and electric market prices, and

[2] *In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 245,* Case No. 12-00350-UT, Final Order Partially Adopting Recommended Decision (Mar. 26, 2014).

SPS's system load and generation mix. Because rates from this case are expected to be effective no earlier than March 1, 2016, use of forecasted fuel and purchased power costs for 2016 is appropriate. SPS's forecast for 2016 is a reasonable estimate of SPS's fuel and purchased power costs to be included in the 2016 Base Fuel factor calculation.

III. DETERMINATION OF TEST YEAR FUEL AND PURCHASED POWER COST

Q. Please describe how SPS's forecasted Test Year fuel and purchased power expense was developed.

A. SPS used the PLEXOS® Integrated Energy Model ("PLEXOS®") software to develop the total system fuel and purchased power expense for the Test Year. PLEXOS® simulates SPS generation resources, its contractual assets, and the Southwest Power Pool ("SPP") electric market to meet SPS's load requirements. The PLEXOS® simulation inputs include variables such as: (i) SPS's system load forecast; (ii) generating unit characteristics and operating parameters including thermal heat rates, minimum and maximum operating capacities, hourly wind and solar production forecasts, planned maintenance schedules, and forced outage rates; (iii) committed purchases and sales; (iv) fuel commodity prices; (v) transmission area constraints; and (vi) SPP forward hourly electric market prices. In addition to the fuel and purchased power costs produced by the model, there are some fuel and purchased power costs that do not affect the dispatch of the resources that are added to the model cost output, such as gas pipeline reservation costs, gas storage costs, and renewable energy costs directly assigned to New Mexico retail customers. Finally, since the PLEXOS® model is developed only for the SPS system rather than the SPP footprint, it does not forecast congestion costs and Transmission Congestion Rights ("TCR"). Therefore, an estimate for these charges is included in the forecast based on historical charges.

Q. Was the PLEXOS® model used in developing SPS's fuel and purchased power expense included in the 2014 Base Fuel?

A. No. Previously, a software package called Planning and Risk, that was licensed from Ventyx, an ABB Company, was used to forecast fuel and purchased power costs. The underlying "engine" for Planning and Risk software was the PROSYM® program.

Q. Why did SPS implement different production modeling software?

A. SPS periodically reviews the capabilities of software vendors to determine if it can improve its production modeling capabilities. Criteria used to evaluate production simulation software include accuracy, capabilities to meet current internal and regulatory requirements, capabilities to meet future needs, ease of use, and product support. Based on these criteria, the PLEXOS® software was identified as a viable alternative to PROSYM®.

PLEXOS® is capable of providing the same or similar output data that was provided from PROSYM® simulations, such as system generation and cost and unit level generation and cost for SPS-owned plants and purchased power agreements ("PPAs"). It was determined the PLEXOS® software will meet current needs, as well as potential future needs, while improving forecast accuracy.

Q. How is the 2016 Test Year fuel and purchased power cost forecast used to develop the requested amount of base fuel included in the cost of service?

A. As discussed more thoroughly in Sections IV and V below, various inputs are incorporated into the PLEXOS® model to develop fuel and purchased power expense for the Test Year. SPS witness Evan D. Evans, as described in his direct testimony, takes the fuel and purchased power expense developed by PLEXOS® and develops the fuel and purchased power costs applicable to New Mexico retail customers.

IV. COMPARISON OF FUEL AND PURCHASED POWER COSTS

Q. What is the forecast for the 2016 Test Year fuel and purchased power expense to be included in base fuel?

A. Column B in Attachment DGH-1[3] shows the overall 2016 fuel and purchased power costs are projected to be $757.9 million (total company).

Q. Please compare SPS's 2016 Test Year fuel and purchased power costs to SPS's fuel and purchased power costs used to develop the 2014 Base Fuel factor.

A. Column A in Attachment DGH-1 reflects the forecasted 2014 fuel and purchased power costs (total company) used to develop the current amount of fuel reflected in base rates approved in Case No. 12-00350-UT. As shown in Column C, the overall 2016 costs are projected to decrease by $124.3 million, or 14.1% as compared to costs reflected in the 2014 Base Fuel factor.

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[3] Workpapers to Attachment DGH-1 are provided in Attachment DGH-2. This attachment is being provided in electronic format on Attachment EDE-1(Media) to the Direct Testimony of Evan D. Evans.

A. Changes in SPS System Load

Q. What changes in SPS's system load are reflected in 2014 Base Fuel versus 2016 Base Fuel?

A. My testimony addresses SPS fuel and purchased power costs that are based on its total system load. As discussed by SPS witnesses Jannell Marks and Richard Luth, SPS has projected changes in its New Mexico retail load, which is expected to grow significantly between the Base Period[4] and Test Year. However, this increase in retail load is being offset by the expected decrease in wholesale loads. As a result, SPS's total system production is forecasted to increase by 2.3% between 2014 and 2016.

Q. Is the change in total system load a major driver of the change to the Test Year base fuel cost?

A. No. The increase in system load is not a major driver in the change in costs between the 2014 Base Fuel and 2016 Test Year. Rather, projected lower natural gas prices, large additions of low cost wind energy, and the addition of a new five

[4] The Base Period is January 1, 2014 - December 31, 2014.

year Calpine Energy Services L.P. PPA (*i.e.,* Calpine II PPA) outweigh load growth, and lower the overall expected costs.

B. <u>SPS Owned Generation - Coal</u>

Q. Did the PLEXOS® model results for 2016 reflect any changes in the amount of coal generation on the SPS system from 2014?

A. Yes. Total coal generation forecasted for 2016 will decrease by approximately 695 gigawatt-hours ("GWh") or 4.9% compared to coal generation forecasted in the 2014 Base Fuel. The primary driver for the reduction in forecast coal generation is increased wind generation from three new wind energy PPAs, all of which were approved by this Commission in Case No. 13-00233-UT.[5] Wind generation is forecasted to increase by 3,379 GWh or 98.2% for 2016. As such, during times of the day when higher cost units have been reduced to minimum levels and wind generation is at its highest, there can be a need to cycle down coal generation which is the primary contributor to the decline in coal generation forecast for 2016.

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[5] *In the Matter of Southwestern Public Service Company's Application for Approval and Authority to: (1) Enter into Separate Purchased Power Agreements with NextEra Energy Resources' Mammoth Plains and Palo Duro Wind Energy Centers and Infinity Wind Energy; and (2) Recover the Associated Energy Costs through its Fuel and Purchased Power Cost Adjustment Clause,* Case No. 13-00233-UT, Final Order on Recommended Decision (Nov. 13, 2013).

Q. What is the 2016 forecast cost of coal generation compared to the 2014 forecast reflected in present base rates?

A. As shown in Attachment DGH-1, the cost of coal including rail transportation is expected to decrease from the 2014 Base Fuel rate of $20.23 per megawatt-hour ("MWh") to $18.53/MWh in 2016, a decrease of 8.4%. The cost of coal is forecasted to decrease from 2014 to 2016 due to an overall decline in costs for contracted coal purchases, as well as in the diesel surcharge as oil futures have plummeted in the past few months. The rail transportation rates, alternatively, are increasing, though to a lesser extent than the commodity and diesel prices have declined.

Q. What effect does a change in coal generation have on SPS's base fuel calculation?

A. Because coal generation is the lowest cost resource on SPS's system, a decrease in coal generation, relative to the 2014 forecast, has the effect of moving the overall average system cost slightly higher. The decrease of 695 GWh of low-cost coal generation is largely replaced by wind generation at a slightly higher cost per MWh, which tends to drive the average system cost slightly higher. However, in the current environment of low natural gas prices, overall system costs are forecast to be $124.3 million less than the 2014 forecast.

C. SPS Owned Generation – Natural Gas

Q. How does the amount of SPS-owned, gas-fired generation forecast for 2016 compare to the 2014 forecast?

A. As shown on Attachment DGH-1, the total SPS-owned, gas-fired generation in 2016 is forecast to decrease by approximately 2,013 GWh, or about 50%, in comparison to the 2014 forecast used to determine the 2014 Base Fuel costs. The primary reason for the decrease is the increase in wind generation forecasted for 2016.

Q. How does the 2016 forecast cost of SPS-owned, natural gas-fired generation compare to the 2014 forecast?

A. Natural gas commodity prices as reflected by the Waha delivery point are projected to decrease 24%, from the 2014 forecast of $4.00/MMbtu to $3.03/MMbtu for 2016. Therefore, the cost of SPS-owned, natural gas-fired generation is also expected to decrease from the 2014 forecast of $52.97/MWh to $49.83/MWh in 2016. Although natural gas commodity costs are primary generation cost drivers, there are also non-commodity fixed costs related to natural gas pipeline transportation that do not follow natural gas commodity cost changes. Since the non-commodity fixed charges are all included in costs for SPS-owned natural gas generation, the reduction in cost per MWh shown on Attachment DGH-1 appears lower than the reduction observed in the natural gas commodity prices themselves.

Q. Why are 2016 natural gas forward prices projected to be lower than forecast 2014 commodity prices?

A. Natural gas prices forecast for 2014 were appreciably higher than the current forecast for 2016. This is because current daily production continues to grow, especially in the Marcellus region, and outpace daily demand. This has allowed for storage inventories to return to average levels and there is continued strong supply going into the injection season. Given these impacts, natural gas prices are currently forecast to remain low for 2016.

D. Purchased Energy

Q. Please list the different types of purchased power on SPS's system.

A. Purchased power on the SPS system can be grouped into four categories: (1) long- and short-term PPAs from gas and co-generation resources; (2) purchases from wind resources; (3) long-term PPAs from solar resources; and (4) short-term market purchases.

Q. Please describe any expected changes involving purchased power that occurred between the 2014 and the Test Year.

A. First, SPS entered into the Calpine II PPA for an additional 200 megawatts ("MW") of capacity and associated energy which began in June of 2014. As such it is available during the entire Test Year versus seven months of availability in the 2014 forecast. This PPA was approved in Case No. 12-00235-UT[6] and is in effect through May of 2019. It is in addition to a previous 200 MW purchase from Calpine approved in Case No. 10-00170-UT[7] (*i.e.,* Calpine I PPA) The energy purchased under the Calpine I and Calpine II PPAs is generated by combined cycle units, which are cost-effective natural gas generating units.

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[6] *In the Matter of Southwestern Public Service Company's Application for Approval and Authority to: (1) Enter Into a Contract for the Purchase of 200 MW of Capacity and Associated Energy from Calpine Energy Services, L.P. for the Period June 2014 Through May 2019; and (2) Recover All Energy Related Costs Through its Fuel and Purchased Power Cost Adjustment Clause,* Case No. 12-00235-UT, Final Order Adopting Recommended Decision (Jan. 15, 2013).

[7] *In the Matter of Southwestern Public Service Company's Application for: (1) Issuance of a Certificate of Public Convenience and Necessity for an Additional Combustion Turbine at Jones Station in Lubbock County, Texas; and (2) Approval of a Contract for the Purchase of Capacity and Energy from Calpine Energy Services, L.P. from 2012 through 2018 in Accordance with Case No. 08-00354-UT*, Case No. 10-00170-UT, Final Order Adopting Certification of Stipulation (Dec. 30, 2010).

Second, SPS has entered into contracts for 697 MW of nameplate wind energy through PPAs for the Roosevelt, Palo Duro, and Mammoth wind facilities. These added wind energy contracts are expected to produce over 2,600 GWh of energy in 2016, which is contributing to lower SPS owned coal and natural gas generation as previously discussed.

Third, the 2016 forecast includes purchases from two new solar contracts that are projected to be commercially operational in December 2016 totaling 140 MW. These projects, Roswell Solar and Chaves County Solar, are expected to produce slightly over 22 GWh in 2016. SPS has filed an application for approval of these solar PPAs, which is currently pending in Case No. 15-00083-UT.[8] These projects have been included in the model since it is SPS's practice to include new PPAs in the production cost model once a contract has been signed between SPS and the counterparty. Since these projects are assumed to begin supplying energy late in the Test Year, they do not materially impact the proposed fuel in base for 2016.

[8] *In the Matter of Southwestern Public Service Company's Application for Approval and Authority to: (1) Enter into Separate Purchaesd Power Agreements with NextEra Energy Resources' Roswell and Chaves County Solar Facilities; (2) Recover the Associated Energy Costs through its Fuel and Purchased Power Adjustment Clause; and (3) Establish and Implement a Shared Savings Mechanism;* Case No. 15-00083-UT (pending).

Fourth, the PPA agreements for the Lubbock Power and Light's Brandon and Massengale (96 MW) units expired in September of 2014.

Fifth, three new wind qualifying facilities ("QFs") came online in 2014. These facilities, Fiber Wind, Ralls II, and Pantex, total over 103.8 MW.

Q. What is the forecasted cost of wind PPAs for the Test Year, and how do those costs compare to 2014 Base Fuel costs?

A. Purchase costs for wind are forecasted to decrease by 9% for the Test Year reflecting low prices for the new wind PPAs mentioned above. The 2016 forecast reflects a decrease from \$28.67/MWh in 2014 Base Fuel to \$26.08/MWh in 2016. Wind purchases are comprised of QF purchases from wind farms ("QF Wind") and purchases under PPAs from wind farms ("PPA Wind"). PPA Wind costs are expected to decrease primarily due to new, lower cost wind contracts with significant volumes of energy outweighing escalating price schedules in existing PPA wind contracts.

Q. What is the forecasted cost of SPS's long-term solar PPAs?

A. For the 2014 forecast, the Sun Edison solar facilities were SPS's only contracted solar resources and had an energy cost of \$110.51/MWh. The 2016 contract price increases to \$117.93/MWh.

Currently, SPS attributes $10.00/MWh of the energy price to the Renewable Energy Certificates ("RECs"). The Sun Edison purchase agreement helps SPS meet New Mexico's Renewable Portfolio Standard ("RPS"). The Sun Edison REC costs, as well as the costs for purchases from the Sun Edison facilities (exclusive of amounts attributed to RECs) above system avoided cost are directly assigned to New Mexico retail customers and recovered through SPS's RPS Rider approved in Case No. 12-00350-UT. The costs included on Attachment DGH-1 reflect only the forecasted economic energy costs recovered through Base Fuel.

Q. Are there any costs associated with other long-term solar PPAs included in the 2016 forecast?

A. Yes. As mentioned above, in March 2015, SPS entered into two long term solar PPAs with NextEra Energy Resources' ("NextEra") Roswell Solar, LLC and NextEra Chaves County Solar LLC for the purchase of energy from two 70 MW solar facilities beginning in December 2016. Commission review of these solar PPAs is currently pending. Based on current expected in-service dates, SPS included one month of generation from each facility in its 2016 forecast, which lowers SPS's average purchased solar energy costs for the Test Year.

E. Short-Term Market Purchases

Q. What is the forecasted cost of short-term market purchases for 2016 compared to 2014?

A. Forecasted market purchase costs are expected to decline by $4.2 million due to lower forecast volume of energy purchased of 208 GWh. The reduction in purchased volume is also attributable to higher wind energy purchases under PPAs discussed previously. On a cost per MWh basis, the Test Year reflects a slightly higher average price of $31.55/MWh as compared to $30.31/MWh for the 2014 forecast. The slight increase is due to the inclusion of the net difference between expected SPP congestion costs and TCR credits of $14.6 million. Since joining the SPP market in March 2014, SPS has been subject to various new costs and credits associated with the market. Two of these are congestion and TCR. Since SPS is currently not modeling SPP charges and credits related to congestion costs and TCR, SPS has developed an estimate to include in the Test Year based on 12 months of historical settlement data for these items for the period ending February 2015. Equivalent costs were not included in the 2014 forecast because SPS had no historical basis upon which to develop an estimate.

V. SUMMARY OF PLEXOS® INPUTS

Q. What topic will you discuss in this section of your testimony?

A. I will discuss the process for determining the inputs to the PLEXOS® model used to develop the 2016 Base Fuel costs, and explain how the principal modeling assumptions related to costs and operations were developed.

Q. Please explain SPS's process for determining the inputs to the PLEXOS® model.

A. The inputs to the PLEXOS® model are acquired from many departments across Xcel Energy. Certain inputs, such as customer load, require additional formatting to develop data that can be used by PLEXOS®. The monthly energy and peak demand by customer group provided by the Sales Energy and Demand Forecasting group is entered into the model along with a Typical Meteorological Year ("TMY") shape of hourly load. PLEXOS® distributes the monthly forecast energy to an hourly demand forecast similar in shape to the TMY shape. The retail hourly demand forecast is aggregated with hourly demand projections for wholesale customer groups to become the total hourly load for which the model determines production costs for the Test Year.

Forecasts and assumptions are provided by groups within Xcel Energy that are subject matter experts for the data. For example, the pricing group within the Risk Management Department provides forward monthly prices for natural gas for the PEPL, Waha, and Permian areas as well as other commodity prices. The Gas Planning department provides transport pricing assumed from various supply locations to each plant.

Q. How is forecast coal pricing determined?

A. SPS obtains input data concerning coal and rail contract pricing from Fuel Supply Operations. Coal is modeled according to the terms of individual contracts as well as with forecast spot market price assumptions for open coal positions. Rail rate and diesel surcharge terms for transportation contracts are entered into PLEXOS® according to data provided by Fuel Supply Operations. PLEXOS® modeling provides for contract coal to be consumed evenly across the year and to be fully utilized before turning to simulated spot market coal.

Q. Please explain the model assumptions for renewable resources.

A. For the purpose of modeling production from must-run renewable energy resources, forecast patterns are generated by Power Operations and Purchased Power. For wind generation, Power Operations provides hourly generation patterns based on the location and turbine technology at each facility. During hours when system load is too low to economically take all available must run generation, the model can curtail wind from PPA Wind facilities at the cost of repaying the provider any lost revenues. Curtailment is not permitted for QF Wind,[9] so all forecasted generation from these facilities is used to meet load in the model. Similarly, for solar generation, either Power Operations or Purchased Power provides an assumed hourly generation pattern for each facility, and all energy is used to meet load.

Q. How does SPS establish operating constraints for owned and PPA generators?

A. Energy Supply provides the maintenance schedules for SPS owned fossil generating units planned for the Test Year. Maintenance is planned to avoid the peak demand summer periods so that all generators are available for system reliability during the summer. For certain fossil generating units contracted through PPAs, the counterparty provides planned maintenance schedules so that SPS can model these expected outages as well.

[9] For actual operations, curtailment of QF Wind is permitted for emergency situations, but SPS does not attempt to model such events.

Forced outage rates for generating units are also key input assumptions that PLEXOS® uses to randomly distribute forced outage events across the year in the production forecast. To determine reasonable forced outage rates for SPS owned thermal units, five years of GADS event data is examined for each plant and used to calculate historical forced outage rates. These five years are then averaged to determine the assumed rate for the Test Year. In the case of PPA generating units, estimates come from multiple sources including historical, contracted, and comparable unit availabilities.

Generating unit capabilities for SPS owned and some PPA generators come from performance tests conducted and reported by Energy Supply. These reports determine the model input for unit heat rates and generator maximum and minimum operating capacities. Heat rate input is used in conjunction with fuel prices within the model to determine a portion of the generators forecast operating cost. Capacity input determines how much each generator can contribute to meeting hourly system demand and how much operating range the generators have to respond to hourly changes in demand.

Other plant characteristics such as minimum on-line and off-line hours, start costs, and variable operation and maintenance ("VOM") costs are provided by Energy Supply. Minimum on and off-line hours establish some of the operating constraints that the SPS system actually experiences and provides for a more accurate simulation of production costs. VOM costs are input to the model to capture additional operating costs for generators beyond direct fuel and transportation costs and are necessary for PLEXOS® to determine the least cost dispatch for the SPS system. Generator start-up costs are input to the model to determine the cost to commit and start a generator. Start costs provide PLEXOS® data on economic constraints to generator commitment that are weighed against other cost factors, such as ramping units down to minimum operating levels, in determining the least cost system operation.

Q. What other system settings does SPS include in the PLEXOS® model?

A. PLEXOS® utilizes assumptions for SPS transmission constraints, requirements to meet system operating reserve requirements, and the ability to buy and sell energy within the SPP integrated market.

Q. How does PLEXOS® simulate transactions with the SPP Integrated Market?

A. An hourly price curve based on forward market electric prices provided by the Risk Management pricing group is entered into the PLEXOS® model. The hourly price forecast provides PLEXOS® with hourly pricing signals which are compared with modeled generator costs for each hour. If the model can meet load at a lower cost by purchasing energy from the market via available transmission paths and within system operating constraints, it will do so. Alternatively if the model has available SPS generators that are able to produce energy less costly than that market price, and they are not needed to serve system load or meet operating reserve requirements, PLEXOS® will simulate a sale to the market.

Q. Is PLEXOS® able to model emissions constraints such as those required by the Cross State Air Pollution Rule ("CSAPR")?

A. Yes. Generator emissions are modeled in PLEXOS® and the software has the capability to solve to annual and seasonal emission constraints such as those required by CSAPR. However, for the Test Year, SPS is not enforcing these constraints within the model since it is assumed that SPS will buy emission allowances to comply with the CSAPR legislation as discussed in the testimony of SPS witness David Low.

Q. Are the reports provided for fuel costs and related production cost calculations used in the PLEXOS® model available in a fully functioning electronic format?

A. No. The fuel costs and related production cost calculations for the forecast Test Year rely on the PLEXOS® model, which produces output without showing the underlying calculations used to determine results. PLEXOS® is proprietary software run on Xcel Energy servers and is not available to be provided to anyone who is not a licensee of the software. SPS, however, is willing to rerun the PLEXOS® software to evaluate reasonable input changes that are requested by Commission Staff and intervenors during their review of the filing. In addition, SPS is willing to make Generation Modeling staff available to hold a PLEXOS® technical conference with Staff and intervenors, subject to the terms of the protective order in this case, to provide information on how the model is developed and how the software is used to evaluate production costs.

VI. CONCLUSION

Q. Were Attachments DGH-1 and DGH-2 and the Schedules in the RFP that you sponsor or co-sponsor prepared by you or under your direct supervision and control?

A. Yes.

Q. Do you incorporate the RFP Schedules shown to be sponsored or co-sponsored by you into your testimony?

A. Yes.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

VERIFICATION

STATE OF COLORADO)
) ss.
COUNTY OF DENVER)

DAVID G. HORNECK, first being sworn on his oath, states:

I am the witness identified in the preceding direct testimony. I have read the testimony and the accompanying attachments and am familiar with their contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

DAVID G. HORNECK

SUBSCRIBED AND SWORN TO before me this 22nd day of May, 2015.

SHIRENE M. VAN DUNK
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20014002834
MY COMMISSION EXPIRES FEBRUARY 23, 2017

Notary Public, State of Colorado
My Commission Expires: 2/23/17

Southwestern Public Service Company

Comparison of 2014 Fuel and Purchased Power Costs to 2016 Costs

	(A) CALENDAR YEAR 2014 (BASE FUEL)			**(B) CALENDAR YEAR 2016 (BASE FUEL)**			**(C) CHANGE FROM 2014 TO 2016 (BASE FUEL)**		
	GWh	$000	$/MWh	GWh	$000	$/MWh	GWh	$000	$/MWh
Coal	14,091	$ 285,075	$ 20.23	13,397	$ 248,246	18.53	(695)	$ (36,829)	$ (1.70)
Natural Gas & Oil	4,032	213,539	52.97	2,018	100,578	49.83	(2,013)	(112,961)	(3.14)
Total SPS Owned Generation	18,123	$ 498,614	$ 27.51	15,415	$ 348,824	$ 22.63	(2,708)	$ (149,790)	$ (4.88)
LT Purchased Energy (Gas)	5,935	$ 221,142	37.26	6,134	$ 172,135	28.06	199	$ (49,007)	$ (9.20)
LT Purchased Energy (Wind)	3,442	98,672	28.67	6,821	177,913	26.08	3,379	79,241	(2.58)
LT Purchased Energy (Solar)	108	4,852	44.87	138	4,230	30.75	29	(621)	(14.12)
ST Market Purchases	1,945	58,958	30.31	1,737	54,800	31.55	(208)	(4,159)	1.24
Total Purchases	11,430	$ 383,624	$ 33.56	14,830	$ 409,078	$ 27.58	3,400	$ 25,453	$ (5.98)
Total Fuel & Purchased Energy Cost	29,553	$ 882,238	$ 29.85	30,245	$ 757,902	$ 25.06	692	$ (124,336)	$ (4.79)

(A): 2014 Base Fuel Forecast from Case No. 12-00350-UT
Windsource generation removed ($282.13 million & 4.97 GWh)
Uneconomic & REC portions of SunEd removed ($7.098m)
(B): Coal costs include FOB Mine, Transportation, and Losses
Gas start charges from model output removed ($708,030)
Natural Gas & Oil includes all gas demand costs ($12.625 million for Tolled Plants)
Blackhawk VOM costs removed ($3.4 million)
$5/MWh removed for Wildorado RECs ($3.1 million)
Windsource generation removed ($261.39 million & 4.39 GWh)
Uneconomic portion and REC Costs of SunEd removed
Other SPP Charge estimates category removed
Gas used to start coal units ($866,129) included as cost of Coal generation rather than Natural Gas & Oil commodity as reported on Schedule H

Attachment DGH-2

is provided in

electronic format in

Attachment EDE-1 (Media) to the

Direct Testimony of Evan D. Evans