Exhibit 19

No. 7

1-7) Refer to LPH-5, lines 3-4. Mr. Hansen states that the Montana Public Service Commission questioned the use of GenTrader ®, which prompted NorthWestern to utilize PowerSimm instead. Has the Montana Commission or any other commission similarly questioned the use of PowerSimm? List any dockets in which NorthWestern has utilized PowerSimm in a contested case.

Response No. 1-7) In the Montana Public Service Commission (*"MPSC"*), Docket No. D2013.12.85 in which the MPSC approved NorthWestern's acquisition of 694 MW of hydroelectric generation facilities, NorthWestern used PowerSimm for resource evaluation in the purchase of hydroelectric facilities in Montana. NorthWestern used PowerSimm as the model for the addition of 11 hydroelectric dams. The Montana Public Service Commission commissioned a third party consultant named Evergreen to evaluate the use and validity. The Evergreen report concluded that NorthWestern's modeling efforts and validation were best in class and that the PowerSimm model was a reasonable tool for evaluating the benefits of the proposed purchase. Please see the attached marked for Response to 1-47. Northwestern also used PowerSimm in its Montana 2013 Electric Resource Procurement Plan (N2013.12.84), its QF-1 standard offer dockets since 2013 (D2014.1.5 and D2016.5.39), and avoided cost analysis contested cases with Greycliff Wind (D2015.8.64) and Crazy Mountain Wind (D2016.7.56).

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Review of NWE's Application to Purchase Hydroelectric Facilities

Final Assessment

A Report to the State of Montana, Public Service Commission

March 27, 2014

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1 Executive Summary

In January 2014, the State of Montana Public Service Commission (PSC or Commission) engaged Evergreen Economics (Evergreen) to assist Commission staff in reviewing analysis conducted by NorthWestern Energy (NWE) and Ascend Analytics in support of NWE's bid to acquire 11 hydroelectric generation facilities from PPL Montana. The following constitute the core tasks conducted as part of the final assessment of NWE and Ascend Analytics:

- An overall assessment of the PowerSimm model as a reasonable tool for evaluating the costs and benefits of NWE's proposed purchase of the hydroelectric generating facilities compared to realistic, available alternatives
- An assessment of the general capabilities of the PowerSimm model and its internal logic
- An assessment of any features of the PowerSimm model that were customized for NWE's application
- An assessment of the reasonableness of inputs to the model, including inputs used in additional model runs generated during the proceedings prior to March 28, 2014
- An assessment of the completeness of NWE's modeling effort with respect to accepted best practices for electric utility long-term resource planning
- An assessment of the reasonableness of NWE's model validation effort with respect to accepted best practices for utility long-term resource planning

The following is a summary of Evergreen's findings with respect to these tasks.

In Evergreen's opinion, the PowerSimm model is a reasonable tool for evaluating the costs and benefits of NWE's proposed purchase of the hydroelectric generating facilities compared to realistic, available alternatives based on the following criteria that reflect industry best practices:

- The representation of the resources and operations of NWE's current generating system in PowerSimm provides a sound baseline for evaluation of alternative resource portfolios. With the addition of the three supplemental scenarios requested by the Commission, NWE's evaluation addresses a reasonably complete set of realistic scenario alternatives
- The representation of future electric demand in PowerSimm provides a sound basis for the evaluation of the costs and benefits of alternative NWE resource portfolios to meet electric demand over the 30-year forecast horizon.
- The PowerSimm model generally captures the important costs and benefits of the proposed hydroelectric facilities, at a level of detail needed to effectively quantify their net value to the NWE system in the future
- NWE's evaluation adequately represents the cost and operating characteristics of plausible alternatives to the proposed hydroelectric facilities
- The PowerSimm analysis is sufficiently robust to effectively simulate the impact of the proposed hydroelectric facilities and alternative resource scenarios on future system operation.
- The PowerSimm analysis captures most of the key risks associated with NWE's proposed purchase of the hydroelectric facilities. However, uncertainty in required maintenance costs and recurring capital expenditures for the facilities should have been explicitly addressed in the risk analysis.

In addition to the above criteria, Evergreen assessed the following:

- **Reasonableness of the primary inputs to the PowerSimm model.** The primary inputs to the PowerSimm model fall into the following categories:
  - natural gas price forecasts
  - electricity price forecasts
  - cost of CO2 emissions
  - Weighted Average Cost of Capital (WACC)

  In Evergreen's opinion, the values used in PowerSimm for each of these inputs appear reasonable and generally agree with other publicly available estimates.

- **The completeness of NWE's modeling effort with respect to accepted best practices for electric utility long-term resource planning.** In Evergreen's opinion, NWE's efforts are fully consistent with industry best practices, with the potential exception that NWE's analysis did not explicitly consider the risk associated with unanticipated costs of maintenance and refurbishment of the hydro assets. Evergreen also finds that, while a full set of realistic resource alternatives to the hydro facilities was represented within the six portfolios considered, a more systematic approach by NWE to determining the optimal resource mix and timing of the alternative portfolios would have been strongly preferred.

- **The reasonableness of NWE's model validation effort with respect to accepted best practices for utility long-term resource planning.** In Evergreen's opinion, while the process for developing and validating stochastic representations of the critical variables used in the Plan was generally sound, the ranges of uncertainty used for some variables did not fully capture the range of values used in resource planning elsewhere in the industry (e.g., CO2 prices, Northwest natural gas prices). In addition, potentially important risks, such as the cost of maintaining and refurbishing the hydro assets into the future, were not included in the stochastic modeling. In our opinion, an improved approach would have used a credible input/sensitivity analysis to 1) quickly identify and communicate the most important uncertainties in the resource planning process and 2) help guide the more detailed modeling of uncertainty performed in PowerSimm.

2 Introduction

In January 2014, the State of Montana Public Service Commission (PSC or Commission) engaged Evergreen Economics (Evergreen) to assist Commission staff in reviewing analysis conducted by NorthWestern Energy (NWE) in support of its bid to acquire 11 hydroelectric generation facilities from PPL Montana. On January 24, 2014, Evergreen delivered to the PSC its adequacy assessment memorandum of the NWE application, which focused on the following two tasks:

A. **Analyze NWE's Application:** Provide the PSC with a preliminary analysis of the scope of key inputs and assumptions of NWE's portfolio analysis; investigate the mechanics of the PowerSimm model, the structural relationship between inputs and outputs, and the model's capacity to evaluate alternative resource scenarios and assist Commission staff in gaining an understanding of PowerSimm.
B. **Assess the Adequacy of NWE's Application:** Provide the PSC a written assessment of the adequacy of NWE's December 20, 2013 application in terms of its use of PowerSimm to provide the PSC with an adequate analysis of long term supply costs for an adequate set of alternative portfolio strategies.

Based on our review of NWE's application and supporting documents, we concluded that the application fell short of providing the PSC with all of the information necessary to evaluate NWE's application, including information required by the Administrative Rules of Montana. The shortcomings we identified in the adequacy assessment fall into the following areas:

- Clarifications on key inputs
- Sources of electrical generation cost inputs
- Adequacy of the three portfolios as a set of feasible alternatives

We discuss each of these areas in detail in the adequacy assessment memo, which is included as Appendix B of this report.

2.1 Final Assessment Tasks

As defined in the Electric Utility Resource Cost Modeling Consultant Service Contract (PSC14-2746V) (the Contract) between the State of Montana, Public Service Commission and Evergreen Economics, Inc. from January 1, 2014, the scope of tasks to be completed by March 28, 2014 and presented in the final assessment are as follows:

1. An overall assessment of the PowerSimm model as a reasonable tool for evaluating the costs and benefits of NWE's proposed purchase of the hydroelectric generating facilities compared to realistic, available alternatives
2. An assessment of the general capabilities of the PowerSimm model and its internal logic
3. An assessment of any features of the PowerSimm model that were customized for NWE's application

4. An assessment of the reasonableness of inputs to the model, including inputs used in additional model runs generated during the proceedings prior to March 28, 2014
5. An assessment of the completeness of NWE's modeling effort with respect to accepted best practices for electric utility long-term resource planning
6. An assessment of the reasonableness of NWE's model validation effort with respect to accepted best practices for utility long-term resource planning

2.2 Remainder of the Report

The final assessment was developed based on review and analysis of documents provided by NWE, as well as based on conference calls between Evergreen and representatives from NWE and Ascend Analytics. Ascend Analytics is the firm that developed PowerSimm and conducted the portfolio analysis for NWE's 2013 Resource Procurement Plan (RPP), which is the primary supporting document for NWE's application for the hydroelectric asset purchase.

Chapter 3 of the report presents our findings with respect to each of the six tasks listed above. In addition, Appendix A presents a list of questions posed to representatives of Ascend Analytics about PowerSimm and the use of PowerSimm to conduct the portfolio analysis and Evergreen's summary of their responses. Appendix B presents the adequacy assessment memo delivered to PSC on January 24, 2014.

3 Final Assessment

3.1 Overall assessment of PowerSimm as a tool for evaluating the costs and benefits of NWE's proposed purchase of the hydro facilities compared to realistic, available alternatives

As stated in the Contract, a key element of the Final Assessment is Evergreen's overall assessment of the quality and effectiveness of NWE's evaluation of the costs and benefits of the proposed purchase of the hydroelectric facilities compared to realistic, available alternatives. Evergreen's assessment applies the following criteria, which are consistent with industry best practices for electric generation resource planning:

Does NWE's evaluation provide an effective evaluation of its current generating system resources and operations?
In Evergreen's opinion, the representation of the resources and operations of NWE's current generating system in PowerSimm provides a sound baseline for evaluation of alternative resource portfolios. This baseline is reflected in the Current resource portfolio evaluated in the 2013 Resource Plan.

Does NWE's evaluation include a credible forecast of future electric demand for its service territory, over a sufficient future time horizon to evaluate the impact of new resource options?
In Evergreen's opinion, the representation of future electric demand in PowerSimm provides a sound basis for the evaluation of the costs and benefits of alternative NWE resource portfolios to meet electric demand over the 30-year forecast horizon.

- PowerSimm forecasts NWE system electric demand at the hourly level (8,760 hours per year) for all 30 years of the simulation horizon.
- Modeling load uncertainty uses a structural state-space model for which load is the dependent variable and historical weather and seasonal, day of week and hourly load patterns are the independent variables. The state-space model explicitly captures covariance relationships between each of the independent variables, as well as their relationship to load.
- NWE uses a vector autoregressive approach to ensure that hour-to-hour and day-to-day weather projections follow historical autoregressive patterns. For example, while modeling uncertainty in daily dry-bulb temperature, a statistically valid autoregressive relationship is maintained among the daily time series values.
- Since the forecast methodology relies primarily on the historical relationship between total system load and weather, it does not directly model the impact of other important drivers of future demand—for example, heating and cooling loads, energy efficiency, residential growth or commercial and industrial development plans. However, we do not feel that this is a significant limitation in PowerSimm's representation of demand for this application.
- Extensive validation of PowerSimm simulations of NWE electric load is performed by comparing the range of uncertainty in the simulation to actual NWE load history (see Figures 6-20, 6-21, 6-22, 6-23 and 6-24 of the Plan).

Does the NWE evaluation comprehensively identify all of the resource alternatives to the proposed hydroelectric facilities that could be used to meet future requirements?

The opportunity to purchase the proposed hydroelectric facilities, and the time-sensitive nature of the acquisition, in our view too narrowly limited the set of options initially evaluated in the 2013 Resource Plan. However, with the evaluation of the additional scenarios requested by the Commission during the discovery process, we believe that a reasonably complete set of realistic scenario alternatives has been addressed in the PowerSimm analysis. The full set of portfolios included in the PowerSimm analysis includes:

- Current Portfolio (no new generation resources)
- Current + Combined Cycle (239 MW), online in 2018
- Current + PPL Montana Hydroelectric assets (633 MW), online in 2014
- Current + LMS 100 Combustion Turbine (97 MW), online in 2018
- Current + LMS 100 Combustion Turbine (97 MW) and new Wind above RPS (100 MW), online in 2025
- Current + Combined Cycle (239 MW) and new Wind above RPS (100 MW), online in 2025

Does NWE's evaluation describe the operating characteristics of the proposed hydroelectric facilities at the level of detail needed to quantify their long-term value to the NWE system?

In Evergreen's opinion, the PowerSimm analysis generally captures the important costs and benefits of the proposed hydroelectric facilities, at a level of detail needed to effectively quantify their net value to the NWE system in the future. An assessment of the potential elements to be considered in assessing the net value of the hydro resources is as follows:

- Value of low operating costs: Modeled as having no required fuel burn and low variable operating costs, relative to other generation resources.
- Value as a non-greenhouse gas emitting resource: Captured by explicitly modeling a CO2 price for NWE fossil-fueled generators and an adder to the market price of electricity.
- Value in providing ancillary services such as ramping and spinning reserves: These operating capabilities of the hydros can potentially be modeled using PowerSimm, but were not considered in the analysis, to keep it conservative.
- Capital investment required for acquisition: Capital costs are fully captured in the PowerSimm analysis.
- Age of hydroelectric facilities: The portfolio analysis assumes the hydros remain in operation for the full 30-year simulation period used in the analysis.
- Cost of maintenance and recurring capital expenditures: The analysis includes explicit estimates of required maintenance and recurring capital expenditures to ensure long-term operation of the hydros. However, a potential weakness is that uncertainty in required level of expenditures is not explicitly modeled, and could be an important source of risk.
- Dependence on unpredictable hydrological conditions: The analysis captures variability in hydrological conditions explicitly in the validation of simulated hydro generation output (see Figure 6-28).

Does the NWE evaluation adequately represent the cost and operating characteristics of plausible alternatives to the proposed hydroelectric facilities?

In Evergreen's opinion, the input data to the PowerSimm model provide a realistic representation of the cost and performance characteristics of each of the alternative resources considered in the analysis. Table 5-8 of the original Plan document and Table 2 of the Plan Supplement show the key operating cost and performance parameters needed to evaluate each of the alternatives considered.

Does the PowerSimm analysis used in the NWE evaluation contain an appropriate level of analytic detail to capture the critical factors needed to assess the value of the proposed hydroelectric facilities and alternative resources?

In Evergreen's opinion, the PowerSimm application to the NWE system is sufficiently robust to effectively simulate the impact of the proposed hydroelectric facilities and alternative resource scenarios on future system operation. The PowerSimm application effectively represents the following important attributes:

- Credible short-term and long-term demand forecasts, including validation of load uncertainty
- Generation costs and operating characteristics of all existing resources, with robust simulation framework to consistently evaluate the potential impact of the proposed hydroelectric facilities and alternative resources
- Stochastic simulation methods to capture key long-term and short-term uncertainties that are fundamental to estimating NWE system operating costs
    - Fuel prices
    - Market electricity prices
    - Generating plant outages
    - Intermittence of renewables
    - Hydrological conditions
- Sufficient simulation detail to capture the operating value of the hydroelectric facilities to the NWE system: The value of the hydros in providing ancillary services—such as storage, ramping and spinning reserves—was not modeled.
- A consistent baseline simulation model (the "Current" portfolio) that describes expected system operating results with no new resources added
- Simulation runs capturing the net cost impact of proposed hydroelectric facilities, across all stochastic iterations (outcomes of probabilistic variables)
- Simulation runs capturing the impact of alternative resource portfolios, across the same set of stochastic iterations as for the evaluation of the hydros
- Financial and operational summary of simulation results that compares expected net present value costs, the probability distribution of net present value costs, and the "risk premium" across portfolios, including the hydroelectric facilities and each alternative portfolio

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Does the NWE analysis adequately assess the risks of investing in the hydroelectric facilities or plausible alternatives?

In Evergreen's opinion, while the PowerSimm analysis captured most of the key risks associated with NWE's proposed purchase of the hydroelectric facilities, uncertainty in required maintenance costs and recurring capital expenditures for the facilities should have been explicitly addressed in the risk analysis. The following summarizes the key uncertainties that should be addressed to appropriately evaluate the hydros and plausible alternatives, and our assessment of how effectively they were modeled in PowerSimm:

- NWE Electric Demand: Uncertainty modeled and validated against historical experience (see Figures 6-20, 6-21, 6-22, 6-23 and 6-24).
- Natural Gas Prices: Uncertainty modeled and validated against historical experience (see Figure 6-26).
- Market electricity prices: Uncertainty modeled and validated against historical experience (see Figure 6-25).
- Climate policy, specifically the cost on CO_2 emissions: Uncertainty in CO_2 price modeled using triangular distribution around mean estimate (see Figure 6-12). Range of uncertainty falls at lower end of CO_2 values used for resource planning in other Western utilities (see Figure 6-11).
- Hydrologic conditions: Uncertainty captured in validation of hydro capacity factor against historical experience (see Figure 6-28).
- Wind capacity factor: Uncertainty modeled and validated against historical experience (see Figure 6-29).
- Maintenance or refurbishment requirements of hydroelectric facilities: Treated as deterministic. A probabilistic representation of these costs would have provided a more realistic assessment of the risk of the hydro portfolio.

3.2 Assessment of the general capabilities of the PowerSimm model and its internal logic

The application of PowerSimm to model and compare the impact of alternative resource portfolios in NWE's 2013 Application included the following important capabilities:

Stochastic Modeling: Stochastic analysis enables the model to explicitly capture the impact that uncertainty in key inputs has on the value of each portfolio. The stochastic approach used in PowerSimm measures the value of alternative portfolios across a wide range of simulated future scenarios. Each scenario represents a unique combination of alternative model assumptions about commodity prices, weather, electric demand, market electricity prices and renewable resource generation. By simulating the operation of the NWE system across each scenario, the results can be captured as a probability distribution of the total costs of each portfolio and the net resource position, as well as more detailed summary operating statistics such as plant generation. PowerSimm computed estimates of the probability-weighted average of total costs, as well as the "risk premium" (defined as the expected value of all costs above the mean) using the probability distributions developed for each portfolio.

Structural Correlation between Uncertain Input Variables: In representing uncertainty in important model inputs, PowerSimm captures important correlations and structural relationships between input variables. For example:

- Commodity price forecasts are constructed from currently available futures prices for commodities.
- Variability in weather is modeled as the key driver of electric load, wind generation, hydro generation and spot gas prices.
- Electric load, wind generation, hydro generation and gas prices are, in turn, modeled as the key driver of electricity market prices.

Modeling Commodity Price Scenarios: A key feature of PowerSimm is that it more realistically captures the year-to-year dynamics of commodity prices over the time horizon of a specific scenario, rather than fixing the commodity price at specified "medium," "high" or "low" price trajectories for the entire study period. The forward price curves used in the model are consistent with the prices observed in current spot and futures markets for each commodity. The future price "paths" used in the model are produced by solving a system of simultaneous equations that (1) capture the uncertainty in commodity prices that is inherent in futures prices and (2) preserve the relationships between contract months, as well as other commodities, consistent with historical observations. In addition, the future paths used in the PowerSimm simulations preserve the mean-reversion behavior (i.e., that "spikes" in commodity prices do not typically persist, but tend to return over time to values closer to the average) exhibited in historical price paths.

Modeling Electricity Market Prices: The simulation of market electricity prices is developed from a structural statistical relationship between market prices and important key stochastic variables that include weather, gas prices and electric load. The simulation is not based on an explicit dispatch of regional generation resources under different settings of these variables, but does consider historical covariance between market prices, weather and load.

The simulation of market prices includes two stages. The "Prior to delivery" simulation evolves current price expectations through the end of the simulation horizon. "During Delivery" simulations capture the relationship of physical system conditions (weather, load, supply conditions) on market prices. Validation of market price simulations was conducted and illustrated in Figure 6-25 of the 2013 Resource Plan.

Modeling CO2 Prices: Including a CO2 price in the analysis is important in anticipating the impact of potential regulatory action or legislation controlling the emission of CO2 in the future. PowerSimm incorporates a price on CO2 that reflects the EIA GHG15 (greenhouse gases priced at $15 per metric ton) scenario for baseline projection, consistent with NWE planning practice. To model uncertainty, PowerSimm uses a "triangle" distribution centered on GHG15, and ranging from $0 per ton to two times the annual EIA GHG15 scenario price. The CO2 price is not included in PowerSimm until 2021, reflecting the expectation by NWE of the timing of actual implementation of a carbon policy in the Pacific Northwest.

The CO2 price is added to the projected market price of electricity, which is based on the heat rate of the marginal resource in the region—gas-fired generation. Since carbon directly impacts both the market price of electricity and the operating cost of carbon-emitting generation, the CO2 price is considered a critical uncertainty in the analysis. However, rather than develop an empirical distribution based on projections of carbon costs from a number of sources, NWE assumes the triangle distribution described above, which falls at the low end of the range of carbon tax expectations used by other public and private entities (see Figure 6-11).

Validation of Model Inputs: The PowerSimm application to support the 2013 RPP for NWE contains extensive validation of the following simulated forecasts:

- Commodity prices: Prices for commodities such as natural gas and coal are calibrated to both the averages and uncertainty reflected in forward (futures) contracts for each commodity. In addition, the commodity simulations are tested to ensure a realistic correlation to market electricity prices, and to ensure that the time series of forecast prices demonstrate realistic reversion to the mean behavior.
- Weather: Weather simulations are validated against historical weather patterns to ensure that variability in maximum dry bulb temperatures across the year is consistent with historical experience.
- Electric load: Electric loads are modeled at the monthly, hourly and daily load profile level, and the simulations are compared to historical confidence intervals for each time span. Simulated electric loads are also validated against weather simulations to ensure that the historical relationship between load and weather is preserved.
- Electric spot market prices: Simulated market prices are validated to ensure that simulated results for historical periods match actual historical electricity prices, both in terms of mean values and in the range of uncertainty. As with electric loads, the calibration is performed for monthly and hourly time intervals, and for daily load profiles.
- Gas spot market prices: Simulated gas prices are validated to ensure that monthly variability is consistent with the range of variability in historical gas prices.
- Renewable generation: The simulation produces estimates of monthly variability in both wind output and hydroelectric generation. This variability is tested against the historical variability observed in the output of these resources.

Production Simulation: For each scenario, which represents a unique combination of uncertain model inputs such as temperature, electric load, gas prices and market electricity prices, PowerSimm performs a simulation of the operation of NWE's electricity generation system. The simulation is run for all years of the 30-year horizon under the assumptions defined by the specific scenario. The key characteristics of the simulation include:

- Hourly operational analysis: The simulation uses an hourly time step level of detail to capture the flexibility of generation resources in response to changes in load or plant outages.
- Market-based dispatch: Resources such as thermal plants in which the output level can be controlled ("dispatchable" resources) are dispatched to maximize resource profitability—that is, they are generally operated when the market price of electricity exceeds the variable operating costs of the resource.
- Renewable generation: Renewable resources such as hydro and wind are not dispatched based on market prices, but rather provide the total generation, as well as seasonal and daily

generation profiles, available under the hydroelectric and wind conditions specific to the scenario.

Comparison of Alternative Portfolios: In comparing alternative portfolios to produce the 2013 Plan, PowerSimm evaluated each portfolio option over the same set of alternative scenarios. Generating the results across all scenarios produces a probability distribution of costs for each portfolio for each year of the simulation, as well as a probability distribution of estimates of net present value across all years. The distribution of results for each portfolio can be compared to the distributions of results for the other portfolios. The portfolios can also be summarized and compared in terms of expected value and risk premium. The expected value of costs for each portfolio is the probability-weighted average cost of operating the NWE system across all scenarios considered in the analysis. The risk premium is the probability-weighted average of costs above the expected value (mean value). That is, the risk premium is defined as the average cost across all scenarios where the estimated cost is greater than the mean of all scenarios. For both the expected value and the risk premium calculations, the final results are summarized in terms of net present value across the 30-year planning horizon.

Detailed Outputs: A full system dispatch for each portfolio is performed for each year of each scenario, and at an hourly time step. These results can then be rolled up to weekly, monthly or annual summaries, by adding results over all hours within the year (or breaking out into high-load or low-load periods). Expected values are computed by calculating the probability-weighted average of the results across all scenarios developed for the evaluation. The primary detailed reports include:

- Net Position Report: Contains the annual generation of each generating resource, total load obligations, and net position between total system generation and load.
- Generating Stations Report: Contains detailed dispatch results for each generation resource, including generation output, capacity factor, fuel consumed, revenue and key operating cost elements (fuel, emissions, variable O&M).
- Portfolio Supply Costs Report: Includes annual portfolio-level results for market purchases, power sales, fixed costs and operating costs for each portfolio evaluated used in the study.

3.3 Assessment of any features of the PowerSimm model that were customized for NWE's application

To Evergreen's knowledge, there were no significant changes to the core modeling capabilities of PowerSimm that were customized to the specific needs of NWE in supporting evaluation of the 2013 Resource Plan. Customization for the purposes of the 2013 Plan focused on incorporating and validating NWE-specific data describing electric loads, commodity prices, regional market electricity prices, thermal generation cost and performance, and renewables cost and performance, including the proposed hydroelectric facilities.

3.4 Assessment of the reasonableness of inputs to the model, including inputs used in additional model runs generated during the proceedings prior to March 28, 2014

NWE relied on a set of key inputs and assumptions to develop alternative portfolios of power generation and purchase, which NWE evaluated based on expected revenues and costs. Inputs into the

2013 RPP modeling framework fall into the following categories, which we describe and evaluate below:

- Price Projections for Natural Gas and Electricity
- Carbon Costs
- Weighted Average Cost of Capital

3.4.1 Price Projections for Natural Gas and Electricity

The portfolio analysis required forecasts of electricity and underlying commodity prices to determine future revenues from alternative hypothetical resource portfolios as well as the costs of operating the generation facilities. Before modeling the three alternative portfolios, NWE forecasted natural gas and electricity prices.

Natural Gas Price Forecast
In the Pacific Northwest, a unit of natural gas is the typical marginal unit of electricity production; as such, it is a key determinant of electricity prices. NWE follows this convention and uses natural gas prices as a primary input for electricity price forecasting in PowerSimm as well as estimating costs of production from gas-fired generation facilities.

Simulation of future gas prices is based on a two-stage process. The "Prior to delivery" simulation evolves forward/forecast gas prices through the end of the simulation horizon. "During Delivery" simulations capture the relationship of physical system conditions—in particular weather and resulting load and renewables conditions—on spot gas prices. The simulated spot prices in each month are scaled to be consistent with the final evolved forward gas price simulation (a "forced convergence" process).[1]

For the first 10 years of the planning horizon (2014-2024), the PowerSimm mean forecast is approximately equal to the 2013 Northwest Power and Conservation Council's (NPCC) medium case gas price scenario and the 2013 Energy Information Administration's (EIA) reference case gas price scenario. However, after 2024, the PowerSimm mean forecast falls below these comparison forecasts for each year after 2024.

We believe the generated price projection appears reasonable and is comparable to other sources of price forecasts in the industry. The fact that the NWE gas price forecast varies little from those developed by NPCC and EIA indicates that even with the uncertainty associated with future gas prices, there is a high degree of consensus in the expected value of future gas prices.

Electricity Price Forecast
NWE developed projections of on-peak and off-peak electricity prices based on multiple randomized simulations from historical data of spot prices of electricity and forward price curves, as well as the historical relationship between natural gas and electricity. NWE incorporates the carbon tax into the electricity price forecast beginning in 2021.

PowerSimm develops simulations of market prices using a structural statistical relationship between

[1] Figure 6-26 of the 2013 Resource Plan shows validation results of simulated gas prices.

market prices and important key stochastic variables that include weather, gas prices and electric load. The simulations explicitly consider historical covariance between market prices, weather and load. The simulation of market prices includes two stages. The "Prior to delivery" simulation evolves current price expectations through the end of the simulation horizon. "During Delivery" simulations capture the relationship of physical system conditions (weather, load, supply conditions) on market prices.

The NWE analysis used a "forced convergence" process to ensure that the expectation of future price realizations in the simulation is equal to today's forward price. This essentially involves scaling the expectation of the price simulations by a factor that equates the price simulation to the expected future price. Scale factor = [Forward Price] / [Expectation of Simulated Prices]. The forced convergence is necessary to eliminate "false" arbitrage opportunities between current futures prices and expected future spot prices.

For the first two years of the planning period, NWE's electricity price forecast is approximately equal to the 2013 NPCC electricity price projection (based on delayed implementation of a federal CO2 tax). NWE's price forecast then falls below the NPPC forecast from 2016 to 2021, at which point the carbon penalty enters into the NWE price forecast. The two forecasts are approximately equal for 2021. However, from 2021 to the end of the planning period, the NWE forecast is consistently below the NPPC forecast. A similar relationship exists between NWE's 2013 RPP forecast and NWE's 2011 RPP forecast. NWE's forecast of electricity prices appears reasonable when compared with other, publicly available, forecasts.

3.4.2 Carbon

NWE incorporates a carbon penalty into its projection of future electricity prices as a proxy for a national tax imposed as part of future regulations of greenhouse gases. NWE's RPP assumes this carbon tax would begin in 2021.

The net value of a megawatt hour (MWh) of electricity produced from a hydroelectric facility is equal to the market price of electricity minus the variable cost of hydro generation, which is zero or close to zero. In the NWE analysis, the generation costs of an efficient natural gas plant, which is the typical marginal supply resource for simulations of the regional electricity market, determines the market price of energy for most hours of the year.

Since gas generation typically produces .5 to .6 metric tons of carbon for each MWh of electricity generated, the cost of electricity generated in an efficient natural gas facility will include the cost of any carbon tax. Consequently, the value of electricity produced from a hydroelectric facility will reflect the cost of carbon that would have been emitted by the avoided generation resource, in this case an efficient gas plant.

Since the NWE analysis assumes the marginal generating resource is the same across the three portfolios, the analysis also uses the same electricity price forecast for each of the three portfolios, which means all three portfolios reflect the carbon tax when it is in effect. However, for the combined-cycle portfolio, the impact of the carbon tax on market prices is directly offset by the impact of the carbon tax on combined-cycle generation costs. For the hydroelectric portfolio, the portion of revenue associated with the carbon tax is not offset by the cost of carbon—since none is emitted—and, therefore, represents greater return to the producer.

NWE based its carbon penalty on the EIA Annual Energy Outlook GHG15 case.[2] The EIA GHG15 case assumes a carbon penalty of $15 per metric ton beginning in 2015, increasing by 5 percent each year thereafter. NWE used the EIA projection to develop a carbon penalty, which begins in 2021 at $20.11 per metric ton and increases by 5 percent per year. The carbon tax acts as a "Flat Market Adder," which is an estimate of the impact of the carbon penalty on the average electricity market price.

NWE developed the CO2 price projection outside the PowerSimm model and used it as an input in PowerSimm-based portfolio analyses. PowerSimm assumes a triangular distribution for each year of CO2 prices based on the yearly price representing the mean of the distribution, with zero (i.e., no carbon tax) representing the lower limit of the distribution and double the annual value representing the upper limit of the distribution. It is not clear how these distributional assumptions add value to NWE's analysis.

NWE's modeling assumption that carbon taxation will occur in the United States by 2021, while not a foregone conclusion, may be increasingly likely. The Carbon Disclosure Project (CDP) recently released results from its annual disclosure process in 2013,[3] which find that most companies covered in its report expect some form of regulatory approach to addressing climate change in the future. Furthermore, "many major publicly traded companies operating or based in the United States have integrated an 'internal carbon price' as a core element in their ongoing business strategies". The CDP report states that utility and energy companies in particular are the most likely to employ internal carbon pricing schemes for strategic decision-making. The CDP noted that prices for carbon penalties covered a wide range from US $6-$60 per metric ton of carbon and cited $20 per ton as the average carbon price among utilities in North America.

The future cost of carbon emissions, an externality not currently taxed at the State or Federal level, has a positive and materially significant impact on the value of hydroelectric assets relative to generation assets that do emit carbon. NWE's carbon price assumptions are in line with internal carbon pricing used by other investor-owned utilities (IOUs) for operational and planning purposes. While a national, regional or state carbon tax is not a foregone conclusion, NWE's assumption that a carbon tax will be assessed beginning in 2021 may be reasonable.

3.4.3 Weighted Average Cost of Capital (WACC)

NWE assumes a WACC of 7.14 percent. The WACC is an estimate of the rate of return a third-party buyer would have to pay on the capital used to purchase the assets. NWE computed the 7.14 percent rate based on a weighted average of the cost of equity and the cost of debt required to complete the purchase (Testimony of Brian B. Bird, p39):[4]

[2] EIA. Annual Energy Outlook. April 2013. http://www.eia.gov/forecasts/aeo/table_e1.cfm
[3] CDP. *Use of Internal Carbon Price by Companies as Incentive and Strategic Planning Tool.* December 2013. https://www.cdp.net/CDPResults/companies-carbon-pricing-2013.pdf
[4] There is some degree of ambiguity between the Stimatz testimony, which characterizes the 7.14 percent as the WACC that a third-party purchaser would likely pay for capital, and the Bird testimony, which characterizes the 7.14 percent as the WACC specific to NWE.

Table 1: Components of NWE Cost of Capital

Source of Capital	Allocation	Cost / Return on Investment	Weighted Cost
Debt	52%	4.5%	2.34%
Equity	48%	10.0%	4.80%
		Rate of Return	7.14%

NWE uses the 7.14 percent WACC to discount future costs and revenues in its calculations of net present value (NPV) for each portfolio. The value of the discount rate has a substantial impact on the NPV calculation. The larger the WACC, the more that NWE discounts future costs and revenues in the NPV calculation. NWE does not provide the details of expected future costs and revenues associated with the three portfolios to allow a third-party to understand the relative effect that the 7.14 percent WACC has on the three portfolios. Further, NWE does not enter the WACC into the portfolio analysis as a stochastic variable, thus their analysis assumes that the WACC is known with certainty. This may or may not be a reasonable assumption.

Both the Bird and Stimatz testimony discuss NWE consultation with Credit Suisse indicating that the WACC for a third-party buyer ranges between 6.5 percent and 7.5 percent.

3.5 Assessment of the completeness of NWE's modeling effort with respect to accepted best practices for electric utility long-term resource planning

The 2013 Resource Procurement Plan (RPP) submitted by NWE in December 2013 evaluated three alternative portfolios:

1. NWE's current portfolio as a base case
2. NWE's current portfolio *plus* a 239 MW combined cycle combustion turbine (CCCT) brought online in 2018 and additional wind resources brought online in 2025
3. NWE's current portfolio *plus* acquisition of PPL's hydroelectric facilities

On January 24, 2014, Evergreen Economics submitted an Adequacy Assessment to the MPSC regarding the NWE application for purchase of the hydro facilities. In that assessment, Evergreen concluded that NWE did not provide sufficient documentation demonstrating that these three portfolios bracket the full range of economically feasible portfolios available to NWE and considered in the 2011 RPP.[5]

In our memorandum to the MPSC, we also stated that we do not believe that NWE needed to conduct thorough portfolio analyses of each of the alternative portfolios considered in NWE's 2011 RPP in order to provide the PSC with the information required in ARM 38.5.8228. Rather, we concluded that it would be sufficient for NWE to either conduct portfolio analysis on a small number of additional alternative portfolios or describe in detail why considering such additional portfolios would not be competitive against the hydro portfolio and, therefore, need not be considered.

In February 2014, NWE and MPSC Staff reached agreement on three additional portfolios that NWE would consider.

[5] See Volume 1, Chapter 5 of the 2011 RPP for descriptions of the 60 portfolios.

1. NWE's current portfolio *plus* a 97 MW simple cycle combustion turbine (SCCT) brought online in 2018
2. NWE's current portfolio *plus* a 97 MW SCCT and 100 MW of new wind assets brought online in 2025
3. NWE's current portfolio *plus* a 239 MW CCCT and 100 MW of new wind resources brought online in 2025

In addition to agreeing to conduct the additional portfolio analysis, NWE provided explanations of why the company did not consider portfolios that included supercritical coal, integrated gasification combined cycle (IGCC) or woody biomass. We find these explanations to be sufficient.

3.5.1 Review of NWE's Additional Portfolio Results

In response to a MPSC data request, NWE provided three supplemental portfolio simulations. In addition, NWE made the following updates to the original portfolio simulations to ensure consistency between the original portfolios and the supplemental portfolios:

- Wind simulation includes updated historical data through December 2013 (previously through August 2013).
- NWE added a startup cost of $50/MW ($2013) to the CC unit modeled in the Current + CC portfolio, escalated annually at the projected rate of inflation (2.1%). NWE added this to "properly account for the operating characteristics and costs of the CC unit."
- NWE adjusted variable O&M cost of the CC unit downwards to $1.79/MWh ($2013); the original analysis included startup costs on an average annual basis.
- While an LMS 100 resource was not included in the original portfolio simulations, NWE did provide resource costs in Table No. 5-8 for an LMS 100 asset. The following costs were updated for this asset:
    - Added start up cost of $76/W ($2013)
    - The variable O&M costs for this resource were scaled up from $2.56/MWh to $3.47/MWh. NWE states that the capital costs and fixed O&M were also scaled upward; however, the dollar amounts are shown to be the same for the original and supplemental plans.

The values of parameters assumed for the (original) 2013 RPP and updated for the supplement to the 2013 RPP are as follows:

Current + LMS 100 in 2018

This portfolio includes NWE existing owned and contracted assets and the addition of an LMS aeroderivative simple-cycled combustion turbine brought online in 2018. As described above, Ascend made changes to the operating costs from the original application. Table 2 shows the assumed costs and performance characteristics from the original simulation and supplemental simulation.

Table 2: LMS 100 Resource Parameters

Resource	Nameplate Capacity MW	Capacity @ 3,500 ft. MW	Capital Cost $/kW	Fixed O&M $/kW-YR	Variable O&M $/MWh	Startup Cost $/MW	Heat Rate Btu/kWh
LMS 100 (original)	110	97	$1,087	$17.06	$3.47	$0	8,722
LMS 100 (supplemental)	110	97	$1,087	$17.06	$2.56	$76	8,722

The residual value of the LMS 100 at 2043 was set at 10 percent of the total original capital cost scaled up at inflation (2.1%). The net present value derived from the discounted annual mean simulated costs of this portfolio was $5.852 billion with a risk premium of $422M.

Current + LMS 100 in 2025 + 100 MW Wind in 2025

This portfolio includes NWE existing owned and contracted assets and the addition of an LMS aeroderivative simple-cycled combustion turbine brought online in 2025 and 100 MW of new wind capacity brought online in 2025. To model the new wind production, Ascend used historical hourly wind production data from Judith Gap, Spion Kop and Gordon Butte and calculate weighted average hourly wind production that is scaled to represent a 100MW wind resource. Table 3 shows the assumed costs and performance characteristics for the Current plus LMS:

Table 3: LMS 100 / Wind Resource Parameters

Resource	Nameplate Capacity MW	Capacity @ 3,500 ft. MW	Capital Cost $/kW	Fixed O&M $/kW-YR	Variable O&M $/MWh	Startup Cost $/MW	Heat Rate Btu/kWh
LMS 100 (original)	110	97	$1,087	$17.06	$3.47	$0	8,722
LMS 100 (supplemental)	110	97	$1,087	$17.06	$2.56	$76	8,722
Wind	100	100	$1,524	$49.18	$2.62*	$0	N/A

Note: Wind asset variable O&M represents ancillary service charges (zone 2 regulation). All costs are in 2013 dollars; future costs are scaled at an inflation rate of 2.1 percent per year.

The net present value derived from the discounted annual mean simulated costs of this portfolio was $5.806 billion with a risk premium of $429M.

Current + CC + 100MW Wind in 2025

This portfolio includes NWE existing owned and contracted assets and the addition of a GE 7FA.04 combined cycle turbine brought online in 2025 and 100 MW of new wind capacity brought online in 2025. New wind production was approximated using the same method as detailed above. The portfolio uses the same costs and operating characteristics of combined cycle unit in Current + CC portfolio, but costs were scaled up for inflation to reflect resource start at 2025 rather than 2018. The residual value also increases to 14 percent of original capital costs reflecting the resource being brought online seven years later. Table 4 shows the assumed costs and performance characteristics.

Table 4: CCCT / Wind Resource Parameters

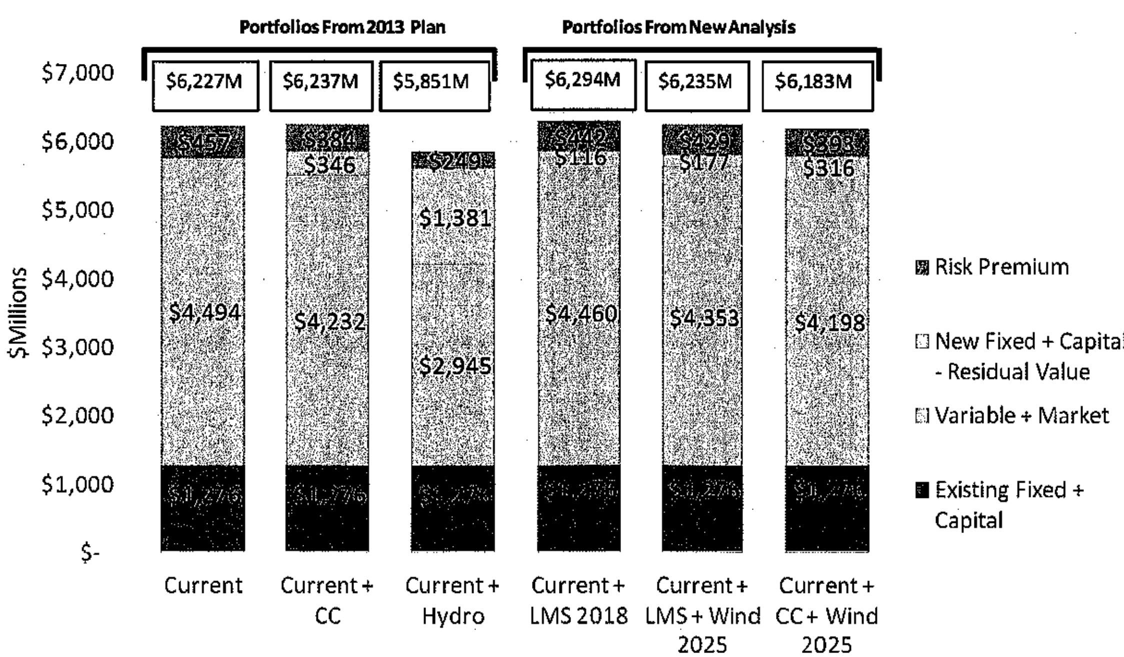
Resource	Nameplate Capacity MW	Capacity @ 3,500 ft. MW	Capital Cost $/kW	Fixed O&M $/kW-YR	Variable O&M $/MWh	Startup Cost $/MW	Heat Rate Btu/kWh
CCCT (original)	270	239	$1,425	$13.94	$3.60	$0	6,660
CCCT (supplemental)	270	239	$1,425	$13.94	$1.79	$50	6,660
Wind	100	100	$1,524	$49.18	$2.62*	$0	n/a

Note: Wind asset variable O&M represents ancillary service charges (zone 2 regulation). All costs are in 2013 dollars; future costs are scaled at an inflation rate of 2.1 percent per year.

The net present value derived from the discounted annual mean simulated costs of this portfolio was $5.790 billion with a risk premium of $393M.

As NWE notes in the supplement to the 2013 RPP, the updates do not significantly influence the total costs of the original portfolios and they do not change the rank ordering of portfolios in the 2013 Plan. The results of the additional portfolios also do not alter the original conclusions of the 2013 Plan with the PPL Hydro asset acquisition remaining the least cost. Figure 6-1 from the supplement (reproduced below) illustrates this.

Figure 1: Net Present Value of Portfolio Costs (from Vol. 1, Figure 6-1 of Supplement to 2013 RPP)



3.5.2 Is Modeling Only Six Alternative Resource Portfolio Consistent with Accepted Best Practices for Long-Term Resource Planning?

It is reasonable that the long-term resource planning process is responsive to the context, in this case, an opportunistic purchase of potentially valuable hydro assets. Given the opportunity, we clearly expect this process to focus on two questions:

1. Do the hydros have long-term value to the NWE system?
2. Are there other resource options that can provide the same or greater value?

With respect to Question 1, we believe that NWE's efforts are fully consistent with industry best practices, with the potential exception that NWE's analysis did not explicitly consider the risk associated with unanticipated costs of maintenance and refurbishment of the hydro assets.

With respect to Question 2, we believe that, while the full set of realistic resource alternatives to the hydro facilities was represented within the six portfolios considered, a more systematic approach by NWE to determining the optimal resource mix and timing of the alternative portfolios would have been strongly preferred.

We believe that, given the significant advantages that NWE found in both total NPV cost and risk premium for the hydros, relative to the alternative portfolios considered, it would be highly unlikely that evaluating additional portfolios would produce a better alternative than the hydros. Nevertheless, we also believe that NWE could have conducted a more systematic approach to determining the optimal mix and timing of the alternatives, which would provide a better reference point in determining the value of the hydro facilities today and would better quantify the value of resource options that NWE could add to its portfolio in the future.

3.5.3 Summary of Findings on NWE's Use of Accepted Best Practices

With respect to accepted best practices for electric utility long-term resource planning, Evergreen assesses NWE's modeling effort in developing the 2013 Resource Plan as follows:

1. NWE provided a consistent evaluation of the proposed hydroelectric facilities and plausible alternatives to the hydro purchase.
2. The NWE evaluation included a credible assessment of the most important commodity prices - natural gas and market electricity prices - including a reasonable representation of uncertainty in these values.
3. NWE used a plausible approach for estimating future electric system demand and for estimating potential variability in annual, seasonal, daily and hourly load patterns needed to properly value alternative generating resources.
4. NWE documented cost and performance characteristics of the proposed hydroelectric facilities and alternative resources, which are consistent with both historical operation and other published sources.

5. Uncertainty in the generation output of existing NWE resources, the proposed hydroelectric facilities and alternative resource options are fully represented based on both expected plant availability (thermal generators) and historical output levels (renewables).
6. NWE did not explicitly model uncertainty in the cost of maintaining and refurbishing the proposed hydroelectric facilities, potentially understating an important source of risk in the acquisition.
7. The core of the NWE evaluation is a credible simulation model of the capacity expansion and operation of the NWE system over a 30-year time horizon that enables effective comparison of the proposed hydroelectric facilities and alternative resource portfolios.
8. The results of the evaluation were effectively summarized as an expected (probability-weighted) net present value of future system operating costs and a "risk premium" that explicitly considers the risk of higher than expected cost for each portfolio, using widely accepted methods of financial analysis.

3.6 Assessment of the reasonableness of NWE's model validation effort with respect to accepted best practices for utility long-term resource planning

3.6.1 Validation of Simulated Prices

To validate the simulation of electricity spot prices, NWE compared simulated spot prices for historical periods to actual historical electricity prices for mean, 10^{th} percentile, and 90^{th} percentile values. The purpose of comparing the 10^{th} and 90^{th} percentile values was to validate the price projections when prices are away from the mean. NWE compared monthly and hourly time intervals, as well as simulated daily load profiles. Figures 6-25 and 6-26 in Volume 1 show comparisons of the historical and simulated Mid-C electric electricity prices for the months of February and August. It is worth noting that conducting the validation at the 10th and 90th percentile means that NWE examined the extremes of the 80 percent most likely prices (100 percent minus 10 percent from each tail equals 80 percent).

While the simulated prices do match the historical prices well, it is important to note that the simulated prices represent an "in-sample" estimate of actual prices. That is, NWE is simply comparing predicted values to the actual values, which NWE used to develop the predicted values. While this does provide some degree of validation of the quality of the model, NWE does not provide any "out-of"-sample" comparisons. That is, they do not hold out some amount of historical data from the simulation model in order to validate the accuracy of the model to predict prices not already observed by the model.

To further test the validity of the simulated electricity spot prices, NWE examined the relationship between electricity price and system load for the simulations and compared this relationship to the actual historical data. Electricity loads and prices are typically highly correlated and Figure 6-27 in Volume 1 confirms that the simulation accurately captures the relationship between historical prices and system load.

NWE simulated future natural gas prices by developing forward price paths that that capture current expectations and uncertainty in future prices while preserving fundamental market relationships and mean reversion behavior. Similar to the validation for electricity prices, NWE compared simulated historical values with actual historical AECO natural gas prices at monthly intervals to preserve the seasonal nature of price variations in natural gas markets. The comparisons of the simulated and actual historical values indicate that the simulated values match closely with the actual historical values.

Lastly, Ascend validated the simulated levels of renewable generation from wind and hydro generating assets. NWE compared the simulations of hydro capacity factors and wind generation to historical monthly data. In general, the historical generation of the hydro facilities fall within the 5th and 95th percentile values of the simulated generation levels. Similarly, historical wind generation levels typically fell within the 5th and 95th percentile of the simulated generation levels. Although, in some cases they did fall outside these bounds, most notably, in the last three months of the simulated year, the majority of the wind assets had a monthly capacity factor in excess of the 95th percentile value of the simulated generation levels.

3.6.2 Validation of Required O&M and Recurring Capital Expenditures to Maintain the Hydro Facilities was not Conducted

NWE assumed that future capital expenditures for the hydro facilities are known with certainty and, therefore, validation of O&M costs was not conducted.

3.6.3 Validation of Weather Simulations

NWE validated weather simulations against historical weather patterns to ensure that variability in maximum dry bulb temperatures across the year is consistent with historical experience.

3.6.4 Validation of Electric load Simulations

NWE validated simulations of electric loads to historical load data, as well as against weather simulations to ensure that the historical relationship between load and weather is preserved.

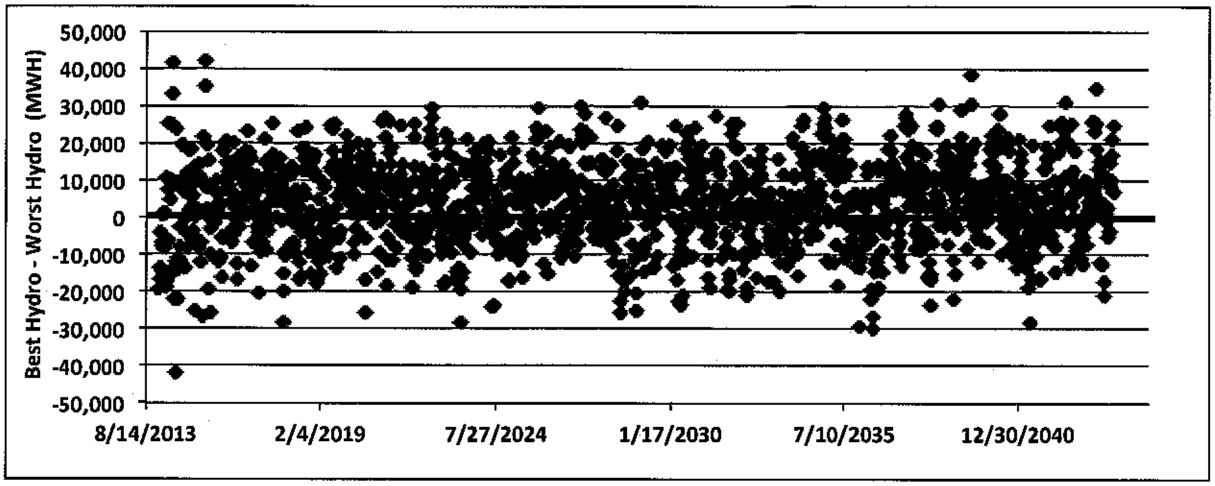
3.6.5 We Find Little Difference in Hydro Output Between the "Best" and "Worst" Scenarios

NWE conducted the portfolio analysis based on a 30-year planning horizon. This is a significant length of time, but is not at all unusual for utility resource planning. Over this 30-year period, the average difference in weekly generation between the Best and Worst hydro scenarios is 3,776 MWh (7.4 percent of average weekly generation for the Best scenario). While this difference is statistically significant, it may not be of great "practical" significance when one considers a planning horizon of such length and the myriad of potential uncertain environmental conditions that could occur over this period.

By definition, the Best and Worst scenarios represent the bookends of uncertainty in the Current + Hydro portfolio. Thus, we believe it is reasonable to be concerned that with respect to generation by the hydro facilities, the portfolio analysis includes relatively little variability. To put this lack of variability in perspective, the standard deviation in weekly generation for the Best and Worst scenarios is 11,290 and 11,687, respectively. The standard deviation is a measure of the average difference in the generation of any week from the average generation of all weeks. Thus, the week-to-week variability for either of these scenarios is more than three times as great as the difference in generation between the two scenarios.

Figure 2 shows the week-by-week difference in generation between the Best and Worst scenarios. The zero line represents no difference in generation; points above the zero line represent weeks in which the generation was greater for the Best scenarios; points below the zero line represent weeks in which generation was greater for the Worst scenarios.

Figure 2: Difference in Weekly Hydro Generation Best Scenario - Worst Scenario



While we understand that NPV of any scenario is composed of much more than generation from the hydro facilities, we anticipated that there would be much greater difference in generation between these two (most extreme) scenarios.

3.6.6 Projected Electricity Prices for the Current + Hydro Portfolio Tend to Be Higher for the Worst Scenario

A stated benefit of the hydro acquisition is protection against market uncertainty including a potential future tax on carbon emissions. Given this, our expectation was that the Best scenario of the Current + Hydro portfolio would have on average higher projected electricity prices than the Worst scenario. This was not the case. Figure 3 shows the week-by-week difference between the Best and Worst scenarios in projected weekly electricity prices for Mid-C on-peak; Figure 4 shows the same difference for the projected price for Mid-C off-peak.[6]

[6] We assume that the projections of on-peak and off-peak Mid-C power costs include NWE's carbon tax expectations.

Figure 3: On-Peak Average Weekly Mid-C Power Cost Per MWh, Best Scenario *Minus* Worst Scenario

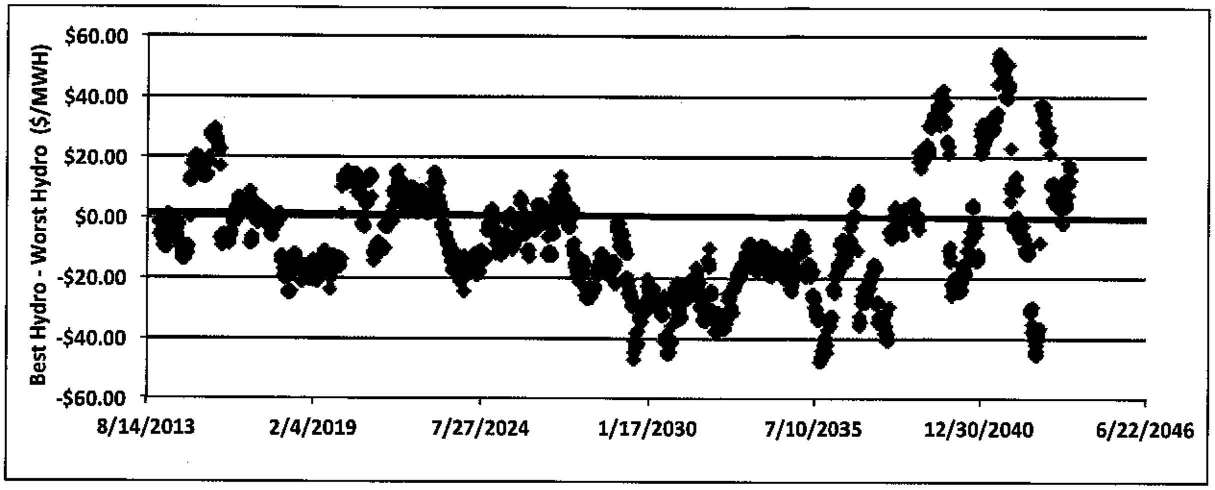
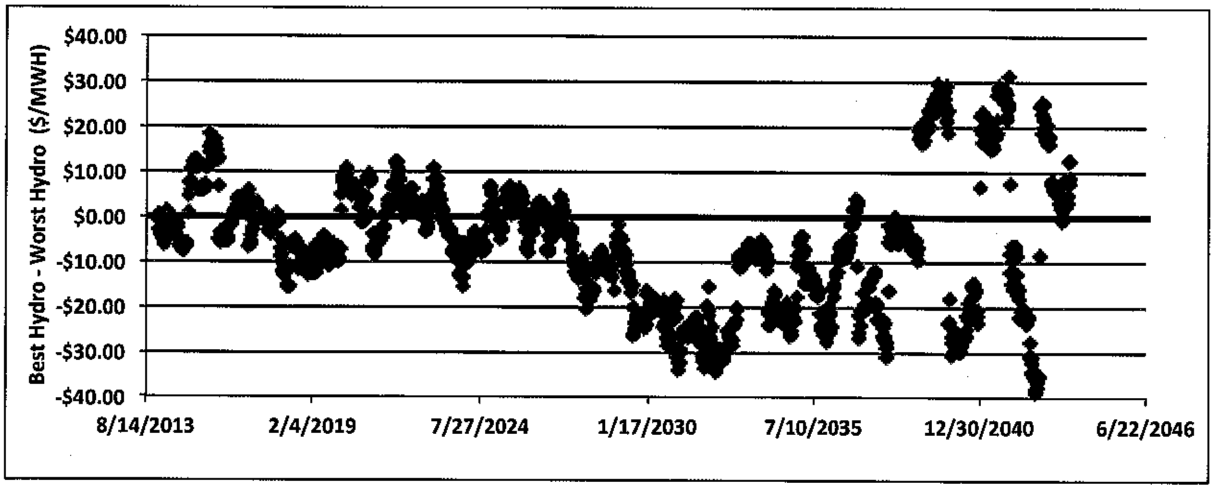


Figure 4: Off-Peak Average Weekly Mid-C Power Cost Per MWh, Best Scenario *Minus* Worst Scenario



3.6.7 Scenario/Sensitivity Analysis in the Context of Long-Term Resource Planning that is Based on Stochastic Modeling

NWE conducted their scenario analysis by randomly drawing values for each stochastic variable from probability distributions based on either historical data or NWE assumptions. NWE contends that the stochastic modeling approach is preferable to a deterministic approach because the stochastic approach explicitly considers historical data, which NWE assumes best represent future conditions. However, as we discuss above, a downside of this approach is that there tends to be a "mean reversion" behavior among the scenarios with exceptionally "bad" and exceptionally "good" draws being rare.

Our opinion is that stochastic modeling and deterministic sensitivity analysis need not be mutually exclusive. Instead, we believe careful use of both approaches can produce better insight into risk than using one or the other alone.

Sensitivity analysis based on deterministically chosen values for one or more inputs quickly identifies and communicates the most important uncertainties in the resource planning process and enables the more detailed risk assessment to focus only on those variables that are most critical to the resource decisions under consideration.

Stochastic modeling explicitly quantifies the range of uncertainty in each key variable based on analysis of observable current values (e.g., futures prices) and historical patterns of uncertainty. The stochastic modeling approach provides realistic future scenarios for evaluating the impact of alternative resource portfolios.

In Evergreen's opinion, while the process for developing and validating stochastic representations of the critical variables used in the Plan was generally sound, the ranges of uncertainty used for some variables did not fully capture the range of values used in resource planning elsewhere in the industry (e.g., $CO2$ prices, Northwest natural gas prices). In addition, potentially important risks such as the cost of maintaining and refurbishing the hydro assets into the future, were not included in the stochastic modeling, but may have been included (or excluded) if a credible input/sensitivity analysis had been performed to demonstrate that this cost was or was not important.

Appendix A: Questions Posed to Ascend Analytics and Summary of Responses

This appendix contains:

- Questions developed by Evergreen Economics regarding the portfolio analysis conducted by Ascend Analytics in support of NWE's 2013 RPP.
- Responses to the questions by Ascend Analytics as understood by Evergreen Economics, and subsequently reviewed by Ascend Analytics.

The questions are organized into three sections:

1. Modeling Uncertainty. Specific questions about the representation of uncertain input variables in the PowerSimm model, and reporting of key uncertain outputs.
2. Commodity and Market Electric Prices. Questions focusing on PowerSimm's representation of natural gas prices, market electricity prices and other commodities important to model results.
3. Electric System Simulation. Questions about the detailed modeling of electric system dispatch used to estimate the costs of operating the NWE system under each of the resource scenarios considered in the analysis.

Modeling Uncertainty

1. **Illustrate the relationships among stochastic variables used in a single iteration. For example, how weather drives hydro conditions and loads (both regional and NWE), and how hydro conditions and load, in turn, drive market prices.**

   Response:

   Figure 6-5 of the 2013 Resource Plan provides the best illustration of the relationships among stochastic variables. These relationships show how the "during-delivery" realization of spot conditions is obtained, after the "prior-to-delivery" evolution of forward/forecast prices is completed. As Figure 6-5 shows, weather is the primary driver of variability, since it affects both electric load and renewables (both hydro and wind) output.

   Market spot prices are obtained based on statistical relationships defined by risk factors and fundamental explanatory variables shown in Figure 6-5. Long-run equilibrium conditions combined with fundamental structural relationships have been used to support development of the monthly forecast values for power. A hybrid approach of market observations and fundamentals generate the hourly prices of electricity that converge on a monthly basis to the simulated forward/forecast prices of electricity.[7]

[7] Representatives of Ascend Analytics commented that this approach captures the key structural relationships without the systematic biases and inconsistencies regional dispatch models have with replicating market price conditions. For example, fundamental models rarely realize implied heat rates consistent with market prices

2. **How does uncertainty in market-level weather and load conditions (used to develop market prices) interact with local weather and load conditions (used to dispatch the NWE system)?**

   Response:

   There is no distinction in the simulation between weather and load simulations at the market-level and local level for the NWE system because the NWE system load explained the behavior in market prices as well as models run with the entire system load. Structural relationships that define central causal effects to price formation are accounted for in the simulations.

3. **Show any analyses you may have performed that prioritize uncertain variables based on the sensitivity of portfolio values to each uncertain variable.**

   Response:

   Ascend showed several payoff diagrams to show sensitivity (marginal/incremental risk attributable to specific risk factors). Ascend did not provide the specific information asked for in question 3 because this would have required rerunning PowerSimm, which had been agreed would not be performed to support these questions.

4. **A key drawback in selecting a set of deterministic scenarios is that judgment and/or political interests are involved in their selection (Chapter 6, Page 10). To what extent is some judgment involved in selecting the mean and range of uncertainty used in stochastic variables when developing the NWE resource plan?**

   Response:

   The distribution of risk factors is developed from historical data and fundamental relationships, with little judgment involved in setting the probability distributions for each of the uncertain variables. The focus is to provide distributions that probabilistically envelope the range of uncertainty in each variable – based on current forward prices and historical variability - and not to exactly forecast future values. The validation of this process focuses on comparing simulated versus historical variability of key each attribute.

5. **Describe the cascading vector auto-regression (VAR) approach used to capture hour-to-hour variability in load, and day-to-day variability in weather relationships.**

   Response:

   The VAR approach is used to ensure that hour-to-hour and day-to-day weather projections follow historical autoregressive patterns. That is, while modeling uncertainty in daily dry-bulb temperature, a statistically valid autoregressive relationship is maintained among the daily time series values.

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during May and June (often off by 50%) and conversely tend to yield implied heat rates that are too low for winter months.

Modeling load uncertainty uses a structural state-space model for which load is the dependent variable and historical weather and seasonal, day of week and hourly load patterns are the independent variables. The state-space model explicitly captures covariance relationships between each of the independent variables, as well as their relationship to load.

6. **Describe the application of a state-space framework to estimate load (dependent variable) as function of weather, seasonal load patterns, and daily load profiles (independent variables).**

   Response:

   Addressed in the response to 5 above

7. **While fixed costs are generally not modeled as stochastic variables in PowerSimm, uncertainty in required O&M and recurring capital expenditures to maintain the hydros at efficient levels of operation seems to be important in evaluating their long-term value. Is there a mechanism in PowerSimm for capturing these uncertainties in the analysis?**

   Response:

   Capital expenditures for the hydro facilities were treated as fixed values in PowerSimm and were provided to Ascend by NWE. The portfolio analysis assumes that there is no uncertainty in future capital expenditures for the hydro facilities.

   While ratepayers may be insulated (at least in the short run) from the risk of higher than expected fixed O&M and recurring capital costs, the potential impact on facility downtime (and consequently production value) if repairs on the aging hydro plants require higher than expected maintenance costs, is not considered.

8. **Unit contingencies considered in modeling uncertainty in system operation appear to include construction risk as well as performance risk. How is construction risk modeled and could this capability be used to capture uncertainty in fixed O&M or recurring capital?**

   Response:

   Addressed in the response to 7 above

9. **The analysis that compares wind output to daily electric load shows a highly negative correlation for a typical high load day. Is this a typical relationship for most wind facilities for all days, or is it most prominent for the summer and winter peak days?**

   Response:

   Wind generation is unlikely to be available on extremely hot or cold days when NWE is most likely to need generation capacity to meet load. Consequently, NWE views wind as primarily an energy resource, but not a dispatchable resource that can be a reliable source of capacity during peak demand periods.

Commodity and Market Electricity Prices

1. **Describe the validated regional simulation used to generate market prices.**

   Response:

   The simulation of market prices is developed from a structural statistical relationship between market prices and important key stochastic variables that include weather, gas prices and electric load. The simulation is not based on an explicit dispatch of regional generation resources under different settings of these variables, but does consider historical covariance between market prices, weather, and load.

   The simulation of market prices includes two stages. The "Prior to delivery" simulation evolves current price expectations through the end of the simulation horizon. "During Delivery" simulations capture the relationship of physical system conditions (weather, load, supply conditions) on market prices. Validation of market price simulations was conducted and illustrated in Figure 6-25 of the 2013 Resource Plan.

2. **Illustrate the creation of gas price based on current forward prices, combined with historical patterns of price variability.**

   Response:

   Simulation of future gas prices is based on a two-stage process. The "Prior to delivery" simulation evolves forward/forecast gas prices through the end of the simulation horizon. "During Delivery" simulations capture the relationship of physical system conditions – in particular weather and resulting load and renewables conditions – on spot gas prices. The simulated spot prices in each month are scaled to be consistent with the final evolved forward/forecast gas price simulation (a "forced convergence" process).

   Figure 6-26 of the 2013 Resource Plan shows validation results of simulated gas prices.

3. **Describe the process used in ensuring that the expectation of future price simulation paths is equal to today's forward price for each future time period.**

   Response:

   PowerSimm uses a "forced convergence" process to ensure that the expectation of future price realizations in the simulation is equal to today's forward price. This essentially involves scaling the expectation of the price simulations by a factor that equates the price simulation to the expected future price. Scale factor = [Forward Price] / [Expectation of Simulated Prices]. The forced convergence is necessary to eliminate "false" arbitrage opportunities between current futures prices and expected future spot prices.

4. **Applying estimates of the price of CO2 emissions to regional market prices uses a marginal emissions rate of .6 tons CO2 per MWH, which essentially assumes that gas-fired generation always operates on the margin. For the NWE system dispatch, emissions of the actual marginal unit were used to compute marginal CO2 emissions for the system. Could this approach have also been used for the market simulation?**

Response:

Since PowerSimm applies a two part approach of simulation of forward/forecast monthly prices and does not explicitly dispatch the regional electric system[8] *to develop hourly market prices, the estimate of marginal CO2 emissions rate is needed to incorporate the costs of CO2 emissions into market prices. The .6 tons of CO2 per MWh is based on the assumption of a combined-cycle combustion turbine technology (CCCT) as the marginal generation resource in every hour of the year, which is consistent with standard industry practice for modeling the impact of CO2 emissions in the Pacific Northwest.*

5. **In validation of the market heat rate (see page 6-34), what valid range of values is used? How are the values in Fig 6-17, showing 4000-5000 Btu / KWh for low load days, explained?**

   Response:

   *The mean values of marginal heat rates during **heavy** load periods (Figure 6-16) vary from roughly 9000 – 13,000 MBtu / MWh over the study period. Seasonal variation in hydro resources drives much of this variability, as can be observed in the annual cyclicality in the graph. The range is roughly consistent with marginal generation shifting between CCCT at the low end to SCCT or another more expensive resource at the high end.*

   *The mean values of marginal heat rates during **light** load periods (Figure 6-17) vary from roughly 5,000 – 9,000 MBtu / MWh over the study period. Seasonal variation in hydro resources drives much of this variability, as can be observed in the annual cyclicality in the graph. The range is roughly consistent with marginal generation shifting between low cost market purchases due to favorable hydro conditions at the low end, to CCCT at the high end.*

6. **Figure 6-36 describes a "low positive correlation" between gas prices and market prices, whereas the actual graph seems to show a fairly strong positive correlation (as we would expect, since gas is typically the marginal generating resource). Please explain.**[9]

   Response:

   To our knowledge, this question was not addressed.

Electric System Simulation

1. **Explain the examples of hourly operation over specific weeks in a single iteration shown in Figure 6-33. Do these results reflect some flexibility for the hydros to reduce output during low-load periods (at night), when value to the system is lowest?**

   Response:

[8] As noted above, Ascend Analytics believes their approach captures the key structural relationships without the systematic biases and inconsistencies regional dispatch models have with replicating market price conditions.
[9] Ascend Analytics noted that this is a matter of interpretation of expectations. There is a positive correlation; it is simply low. Ascend interpret this as low relative to other markets in the US, especially winter peaking markets.

Hydro operation does not respond to market prices in the simulation of the NWE system and, therefore, "cash is left on the table" in that the PowerSimm analysis assumes no ability of the hydros for flexibility in responding to changes in demand and price conditions. Since the hydros will actually have some dispatch flexibility, this represents a more conservative approach in the simulation.

The dispatch is based on combination of "pre-dispatched" generation from hydro and renewables and market-based dispatch of thermal generation resources. The results in Figure 6-33 actually show the hydro and wind facilities are operating based on their full available output, given simulated wind and hydro conditions driven by weather.

2. **Is the time granularity used in the simulation a full 8,760 hours per year, or is it based on simulation of hourly load profiles for selected representative day types?**

   Response:

   The simulation is based on a full 8760 hours per year. Daily load profiles are not used because they limit ability to capture load peaking at very high demand levels (e.g., 95th percentile and above) and load flattening at very low load levels (e.g., 5th percentile and below.

3. **Show simulation results for extreme outcomes that provide both the best case and worst case conditions for valuation of the hydros in the NWE portfolio.**

   Response:

   The payoff diagrams show outcomes across the entire distribution of recent historical outcomes. Figure 6-2 in Volume 1 shows the expected portfolio costs over the projection period and the 95 percent confidence interval based on (recent) historical data.

4. **Describe the interaction of "prior-to-delivery" and "during delivery" simulations. Is it primarily the granularity of the time interval used (e.g., annual or monthly for prior-to-delivery, daily and hourly variations for during delivery)?**

   Response:

   This question is covered in questions 2 and 3 of the Commodity and Market Electricity Prices section above.

5. **Similarly, describe the inter-relationship of forward / forecast prices and spot prices used in the two levels of simulation.**

   Response:

   Evolution of futures prices over time produces the expectation of prices in each future month of the simulation period ("prior to delivery" simulation). Spot prices are then generated using these evolved forward prices, combined with uncertainty in weather, load and commodity prices for each future month. "Forced convergence" ensures that expected spot prices across all simulation iterations equal the final evolved forward price for each contract month.

6. **Can PowerSimm operate in "load serving" mode as well as economic dispatch mode based on market prices? If so, why was the economic dispatch mode used for the NWE resource plan?**

   Response:

   Yes, PowerSimm can operate in both load serving and economic dispatch mode. NWE is a price taker within a much larger market, and currently relies on market purchases to meet their load obligations. Consequently, PowerSimm uses the economic dispatch mode, in which NWE resources are dispatched when they are "profitable" (i.e., variable operating costs are lower than market prices, subject to operating constraints), which better reflects how NWE currently operates within its regional market.

7. **Did you perform any analyses that quantified the ancillary value of the hydros in managing the variability in system generation (especially wind), e.g., "spinning" reserves?**

   Response:

   While it would be possible to model the hydro acquisition to capture the value of ancillary services (e.g., the ability to shape load or provide spinning reserves, using their limited water storage capabilities), the value of these services is small relative to their savings in energy costs. Ascend chose the conservative approach of not modeling these services in the simulation.

8. **Describe the modeling of variability in hydro and wind output at different levels of time granularity (annual / monthly / daily), based on historical output patterns. At what level of time detail is the modeling most critical for assessing the value of each resource?**

   Response:

   Both hydro and wind are modeled considering seasonal, daily and hourly output patterns Figure 6-28 shows the validation of simulated monthly variability in hydro generation versus historical actual output. Figure 6-29 shows the validation of simulated monthly wind generation variability versus actual wind generation results. In general, hourly variability in output is higher for wind than for hydro generation, and therefore has a greater impact on the cost and reliability of NWE system dispatch.

9. **The three new scenarios being modeled have resources introduced to the NWE system in different years (2018 and 2025), which are also different from the timing used in the original scenarios (2014 for the hydros, 2018 for the CCCT, respectively). What is the importance of this timing in the PowerSimm evaluation of these alternative scenarios?**

   Response:

   NWE and Commission staff determined the timing of the installation of new capacity for the three additional scenarios. Ascend believes that due to NWE's open position (i.e., the shortage of owned or controlled generation resources relative to load obligations), there is not a benefit in delaying construction of additional capacity.

10. PowerSimm seems to support optimal capacity-expansion planning, based on a dynamic programming model that considers all potential capacity "states" for a specific iteration. Was this capability used in the actual analysis, or was new capacity (e.g., hydros or CCCT) simply assigned manually in specific years of the study horizon? Is the dynamic programming solution based on a target net position or resource mix, or simply a set of available options for new capacity additions?

Response:

Ascend assigned the timing for bringing new generation capacity on-line outside of the analysis in PowerSimm. Their assumption was that it was optimal to add capacity as soon as possible. For the three additional scenarios, the timing was determined through agreement between NWE and Commission staff, rather than set by Ascend/NWE.

11. Was this optimal capacity expansion capability used for installing new wind capacity to meet NWE RPS requirements?

Response:

No. Ascend simply grew capacity of the existing three wind projects in order to meet the increase in RPS requirements over time.

12. Potential optional analyses appear to include reliability of supply and flexibility functionality. Were results of these optional analyses developed for the hydros?

Response:

No. Ascend does not consider the potential value of the hydro resources with respect to reliability or flexibility. See the response to 7, above.

Appendix B: Adequacy Assessment Memorandum

MEMORANDUM

January 24, 2014

To: Montana Public Service Commission

Re: Adequacy Assessment of NWE Application to Purchase Hydroelectric Facilities

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In January 2014, the State of Montana Public Service Commission (PSC or Commission) engaged Evergreen Economics (Evergreen) to assist Commission staff in reviewing analysis conducted by NorthWestern Energy (NWE) in support of its bid to acquire 11 hydroelectric generation facilities from PPL Montana. The scope of tasks to be performed by Evergreen by January 24 include:

A. **Analyze NWE's Application:** Provide the PSC with a preliminary analysis of the scope of key inputs and assumptions of NWE's portfolio analysis; investigate the mechanics of the PowerSimm model, the structural relationship between inputs and outputs, and the model's capacity to evaluate alternative resource scenarios and assist Commission staff in gaining an understanding of PowerSimm.
B. **Assess the Adequacy of NWE's Application:** Provide the PSC a written assessment of the adequacy of NWE's December 20, 2013 application in terms of its use of PowerSimm to provide the PSC with an adequate analysis of long term supply costs for an adequate set of alternative portfolio strategies.

This memorandum presents the results of Evergreen Economics' preliminary review and analysis of NWE's application for the purchase of the PPL hydroelectric generation facilities. Evergreen relied on reports provided by NWE to complete the assigned tasks. Consistent with the contract between the PSC and Evergreen Economics, Evergreen Economics did not obtain licenses to the PowerSimm program in order to run models or to replicate NWE's modeling efforts.

A. Summary of NWE's Application and Use of PowerSimm

In this section, we present the results of our initial review of NWE's application for the purchase of the PPL hydroelectric generation facilities and associated documents. To assist Commission staff and the Commission in gaining a better understanding of those aspects of the application related to PowerSimm modeling, this section focuses on the following:

1. Review of NWE's inputs and assumptions used to conduct the three alternative portfolios over the planning horizon.
2. Describe NWE's use of PowerSimm to analyze the alternative portfolios

A.1. Review of NWE Inputs and Assumptions

The NWE/PowerSimm model is developed using a set of key inputs and assumptions that define the expected revenues and costs of hypothetical resource portfolios. Inputs into the 2013 RPP modeling framework fall into the following categories, which Evergreen discusses in more detail below:

- Price Projections for Natural Gas, Coal and Electricity
- Carbon Costs
- Electricity Generation Cost
- Other Economic Inputs (Inflation, Weighted Average Cost of Capital)

Below is a review of these inputs and assumptions.

Forward Price Projections
Forecasts of electricity and underlying commodity prices are required to determine future revenues from alternative hypothetical resource portfolios as well as the costs of operating the generation facilities. Prior to modeling the three alternative portfolios, PowerSimm was used to forecast natural gas and electricity prices.

Natural Gas Price Forecast
In the Pacific Northwest, a unit of natural gas is the typical marginal unit of electricity production; as such, it is a key determinant of electricity prices. NWE follows this convention and uses natural gas prices as a primary input for electricity price forecasting in PowerSimm as well as estimating costs of production from gas-fired generation facilities.

To forecast gas prices, historical spot prices for natural gas and forward natural gas price curves are input into the PowerSimm model along with historical weather, load and generation data. PowerSimm then uses this information to develop multiple randomized simulations of future gas price scenarios based on variations in supply and demand for electricity related to underlying weather conditions. This differs from previous RPPs in which NWE developed specific price cases to evaluate different potential scenarios.

Compared with the 2013 Northwest Power and Conservation Council's (NPCC) medium case gas price scenario and the 2013 Energy Information Administration's (EIA) reference case gas price scenario, the PowerSimm mean forecast is approximately equal for the first ten years of the planning horizon (2014–2024), but falls below these comparison forecasts for each year after 2024.

Carbon
NWE incorporates a carbon penalty into its projection of future electricity prices as a proxy for a national tax imposed as part of future regulations of greenhouse gases. NWE's RPP assumes this carbon tax would begin in 2021.

The net value of a megawatt hour (MWh) of electricity produced from a hydroelectric facility is equal to the market price of electricity minus the variable cost of hydro generation, which is zero or close to zero. In the NWE analysis, the market price of energy for most hours of the year is set by the generation cost of an efficient natural gas plant, which is usually the marginal supply resource during simulations of the regional electricity market. If a carbon policy that includes a tax or other cost on the right to emit carbon is implemented in the region, then cost of electricity generated in an efficient natural gas facility will include this cost, since gas generation typically produces .5 to .6 metric tons of carbon for each MWh of electricity generated. A tax on carbon will be reflected in the market price of electricity. Consequently, the value of electricity produced from a hydroelectric facility will reflect the cost of carbon that would have been emitted by the avoided generation resource, in this case an efficient gas plant.

Since the marginal generating resource for the market is not assumed to change across the three portfolios considered, the NWE analysis assumes the same electricity price forecast for each of the three portfolios. In other words, the value of any new generation is assumed to be the same for each portfolio and will reflect the carbon tax when in effect. However, for the combined-cycle portfolio, the additional value due to the impact of a carbon tax on market prices will be directly offset by the impact of the carbon tax on combined-cycle generation costs. For the hydroelectric portfolio, the portion of revenue associated with the carbon tax is not offset by the cost of carbon—since none is emitted—and, therefore, represents greater return to the producer.

NWE based its carbon penalty on the EIA Annual Energy Outlook GHG15 case.[10] The EIA GHG15 case assumes a carbon penalty of $15 per metric ton beginning in 2015, increasing by 5 percent each year thereafter. NWE used the EIA projection to develop a carbon penalty, which begins in 2021 at $20.11 per metric ton and increases by 5 percent per year. The carbon tax acts as a "Flat Market Adder," which is an estimate of the impact of the carbon penalty on the average electricity market price.

NWE developed the CO2 price projection outside the PowerSimm model and used it as an input in PowerSimm-based portfolio analyses. PowerSimm assumes a triangular distribution for each year of CO2 prices based on the yearly price representing the mean of the distribution, with zero (i.e., no carbon tax) representing the lower limit of the distribution and double the annual value representing the upper limit of the distribution.

Electricity Price Forecast

NWE developed projections of on-peak and off-peak electricity prices based on multiple randomized simulations based on historical spot prices of electricity and forward price curves, as well as the historical relationship between natural gas and electricity. NWE incorporates the carbon tax into the electricity price forecast beginning in 2021.

For the first two years of the planning period, NWE's electricity price forecast is approximately equal to the 2013 NPCC electricity price projection (based on delayed implementation of a federal CO2 tax). NWE's price forecast then falls below the NPCC forecast from 2016 to 2021, at which point the carbon penalty enters into the NWE price forecast. The two forecasts are approximately equal for 2021. However, from 2021 to the end of the planning period, the NWE forecast is consistently below the NPCC forecast. A similar relationship exists between NWE's 2013 RPP forecast and NWE's 2011 RPP forecast.

[10] EIA. Annual Energy Outlook. April 2013. http://www.eia.gov/forecasts/aeo/table_e1.cfm

Coal Price Forecast
NWE incorporates a forecast of coal prices into the cost of operation of the Colstrip generation facility; however, there is no discussion of how this forecast was developed or how it compares to other forecasts.

Cost of Electricity Generation
Inputs considered in the portfolio analysis (see 2013 RPP, Table 5-8) include the nameplate capacity, capital costs, fixed O&M costs, variable O&M costs and heat rate by generation resource. NWE does not provide sources of the cost information for the hydro or other generating assets.[11] The RPP is also not clear as to whether the costs associated with the hydro facilities (shown in Table 5-8) enter the portfolio analysis as fixed values or as stochastic values drawn from a distribution developed from historical cost data. This distinction matters because the estimates of the "risk premium" presented in Volume 1, Chapter 6 show that the hydro portfolio has a substantially lower-risk premium than the other two portfolios. If the projections of costs for the hydro portfolio are based on fixed values (i.e., are deterministic), this likely explains at least some of the difference in the risk premium between the alternative portfolios.

Inflation
The PowerSimm analysis assumes a 2.1 percent inflation rate, which NWE applies to the forecast of electricity prices beginning in 2020 and continuing through the end of the projection. The inclusion of inflation accounts for the absence of forward price curves this far in the future. NWE also applies the inflation rate to estimates of costs for 2014 to develop estimates of costs for future years. Again, it is unclear if the costs enter the model as fixed values or as draws from a probability distribution.

Weighted Average Cost of Capital (WACC)
NWE assumes a WACC of 7.14 percent. The WACC is an estimate of the rate of return a third-party buyer would have to pay on the capital used to purchase the assets. NWE computed the 7.14 percent rate based on a weighted average of the cost of equity and the cost of debt required to complete the purchase (Testimony of Brian B. Bird, p39):[12]

Source of Capital	Allocation	Cost / Return on Investment	Weighted Cost
Debt	52%	4.5%	2.34%
Equity	48%	10.0%	4.80%
		Rate of Return	**7.14%**

NWE uses the 7.14 percent WACC to discount future costs and revenues in its calculations of net present value (NPV) for each portfolio. The value of the discount rate has a substantial impact on the NPV calculation. The larger the WACC, the more that NWE discounts future costs and revenues in the NPV calculation. Table 1 presents a summary of the inputs for the PowerSimm used by NWE and Ascend Analytics.

[11] Joseph Stimatz testimony includes projected annual costs for the hydro facilities, seemingly obtained from PPL. It is unclear if these are the same costs that were included in the portfolio analysis conducted in PowerSimm.
[12] There is some degree of ambiguity between the Stimatz testimony, which characterizes the 7.14 percent as the WACC that a third-party purchaser would likely pay for capital, and the Bird testimony, which characterizes the 7.14 percent as the WACC specific to NWE.

Table 1: Inputs Considered by NWE in the Three Portfolios

Input	Description	Comments
Natural Gas Price Forecast	Generally regarded as the marginal price of producing electricity	Gas price forecast for 2013 RPP below 2011 RPP forecast; is about equal to both the 2013 EIA and 2013 NPCC's forecast through the first 10 years of the planning horizon and below both forecasts in the latter 10 years.
Electricity Price Forecast	Based on historical relationship with natural gas prices, historical spot prices and forward price curves	Includes "Flat Rate Adder" carbon penalty of $13.52/MWh beginning in 2021 and growing by 5 percent per year thereafter; 2013 RPP is below the 2011 RPP forecast and 2013 NPCC forecast.
Carbon Price Adjustment	Serves as a proxy for a potential penalty imposed as part of greenhouse gas regulation at some point in the future	The cost of thermal generating resources may include a carbon penalty in the future. 2013 RPP assumes this penalty will begin to be implemented in 2021 at a price of $20.11 growing 5 percent per year.
Coal Price Forecast	The estimated price of coal used to develop the cost of generation at the Colstrip plant	No explanation of how the coal price forecast was developed is provided.
Resource Operation and Cost Information	The resource operation characteristics such as nameplate capacity and heat rate as well as capital and operation costs of generating facilities	Resource operation and cost information is provided for alternative generation facility scenarios; however, the source of this information or how it was derived is not provided. Cost information is not provided for the current portfolio.
Inflation	Persistent increase in the general price of electricity and operating costs	2.1 percent per year. Used to scale current generating costs and commodity prices after 2020.
WACC	Weighted Average Cost of Capital. The rate of return a buyer will have to pay for capital to purchase assets	7.14 percent. The WACC is used as the discount rate for present value calculations.

Source: Analysis by Evergreen Economics of information provided by NWE

A.2. Use of PowerSimm to Analyze the Alternative Portfolios

The application of PowerSimm to model and compare the impact of alternative resource portfolios in NWE's 2013 Application included the following important capabilities:

Stochastic Modeling: Stochastic analysis enables the model to explicitly capture the impact that uncertainty in key inputs has on the value of each portfolio. The stochastic approach used in PowerSimm measures the value of alternative portfolios across a wide range of simulated future scenarios. Each scenario represents a unique combination of alternative model assumptions about commodity prices, weather, electric demand, market electricity prices and renewable resource generation. By simulating the operation of the NWE system across each scenario, the results can be captured as a probability distribution of the total costs of each portfolio and the net resource position, as well as more detailed summary operating statistics such as plant generation. PowerSimm computed estimates of the probability-weighted average of total costs, as well as the "risk premium" (defined as the expected value of all costs above the mean) using the probability distributions developed for each portfolio.

Structural Correlation between Uncertain Input Variables: In representing uncertainty in important model inputs, PowerSimm captures important correlations and structural relationships between input variables. For example:

- Commodity price forecasts are constructed from currently available futures prices for commodities.
- Variability in weather is modeled as the key driver of electric load, wind generation, hydro generation and spot gas prices.
- Electric load, wind generation, hydro generation and gas prices are, in turn, modeled as the key driver of electricity market prices.

Modeling Commodity Price Scenarios: A key feature of PowerSimm is that it more realistically captures the year-to-year dynamics of commodity prices over the time horizon of a specific scenario, rather than fixing the commodity price at specified "medium," "high" or "low" price trajectories for the entire study period. The forward price curves used in the model are consistent with the prices observed in current spot and futures markets for each commodity. The future price "paths" used in the model are produced by solving a system of simultaneous equations that (1) capture the uncertainty in commodity prices that is inherent in futures prices and (2) preserve the relationships between contract months, as well as other commodities, consistent with historical observations. In addition, the future paths used in the PowerSimm simulations preserve the mean-reversion behavior (i.e., that "spikes" in commodity prices do not typically persist, but tend to return over time to values closer to the average) exhibited in historical price paths.

Modeling Electricity Market Prices: Projections of electricity market prices are produced by simulating the operation of generating resources in the mid-Columbia region over the 20-year planning horizon. This regional simulation, which NWE has validated by "backcasting" results and comparing to actual observed historical market prices, provides market prices used to simulate NWE system dispatch decisions. The first step in the regional simulation is to estimate electric load, which is a key driver of regional electricity prices. The load simulation uses a statistical approach known as a structural state-space model that estimates electricity demand (the dependent variable) as a function of seasonal demand patterns, daily and hourly time-series patterns, and weather (the independent variables). This approach also generates estimates of uncertainty in the demand simulation, as a direct output of the statistical model. Given the load forecasts and simulations of future gas prices, market prices are developed by simulating the operation of the regional electricity generation system, factoring in

- Amount and availability of different generation resources;
- Economic dispatch order of the resources;
- Imports and exports;
- Unplanned unit outages; and
- Transmission outages.

Modeling CO2 Prices: Including a CO2 price in the analysis is important in representing the potential for regulatory action or legislation controlling the emission of CO2 in the future. PowerSimm incorporates a price on CO2 that reflects the EIA GHG15 (greenhouse gases priced at $15 per metric ton) scenario for baseline projection, consistent with NWE planning practice. To model uncertainty, PowerSimm uses a "triangle" distribution centered on GHG15, and ranging from $0 per ton to two times the annual EIA GHG15 scenario price. The CO2 price is not included in PowerSimm until 2021, reflecting the expectation by NWE of the timing of actual implementation of a carbon policy in the Pacific Northwest.

The CO_2 price is added to the projected market price of electricity, which is based on the heat rate of the marginal resource in the region—gas-fired generation. Since carbon directly impacts both the market price of electricity and the operating cost of carbon-emitting generation, the CO_2 price is considered a critical uncertainty in the analysis.

Validation of Model Inputs: The PowerSimm application to support the 2013 RPP for NWE contains extensive validation of the following simulated forecasts:

- Commodity prices: Prices for commodities such as natural gas and coal are calibrated to both the averages and uncertainty reflected in forward (futures) contracts for each commodity. In addition, the commodity simulations are tested to ensure a realistic correlation to market electricity prices, and to ensure that the time series of forecast prices demonstrate realistic reversion to the mean behavior.
- Weather: Weather simulations are validated against historical weather patterns to ensure that variability in maximum dry bulb temperatures across the year is consistent with historical experience.
- Electric load: Electric loads are modeled at the monthly, hourly and daily load profile level, and the simulations are compared to historical confidence intervals for each time span. Simulated electric loads are also validated against weather simulations to ensure that the historical relationship between load and weather is preserved.
- Electric spot market prices: Simulated market prices are validated to ensure that simulated results for historical periods match actual historical electricity prices, both in terms of mean values and in the range of uncertainty. As with electric loads, the calibration is performed for monthly and hourly time intervals, and for daily load profiles.
- Gas spot market prices: Simulated gas prices are validated to ensure that monthly variability is consistent with the range of variability in historical gas prices.
- Renewable generation: The simulation produces estimates of monthly variability in both wind output and hydroelectric generation. This variability is tested against the historical variability observed in the output of these resources.

Production Simulation: For each scenario, which represents a unique combination of uncertain model inputs such as temperature, electric load, gas prices and market electricity prices, PowerSimm performs a simulation of the operation of NWE's electricity generation system. The simulation is run for all years of the 20-year horizon under the assumptions defined by the specific scenario. The key characteristics of the simulation include:

- Hourly operational analysis: The simulation uses an hourly time step level of detail to capture the flexibility of generation resources in response to changes in load or plant outages.
- Market-based dispatch: Resources such as thermal plants in which the output level can be controlled ("dispatchable" resources) are dispatched to maximize resource profitability—that is, they are generally operated when the market price of electricity exceeds the variable operating costs of the resource.

- Renewable generation: Renewable resources such as hydro and wind are not dispatched based on market prices, but rather provide the total generation, as well as seasonal and daily generation profiles, available under the hydroelectric and wind conditions specific to the scenario.

Comparison of Alternative Portfolios: In comparing alternative portfolios to produce the 2013 Plan, PowerSimm evaluated each portfolio option over the same set of alternative scenarios. Generating the results across all scenarios produces a probability distribution of costs for each portfolio for each year of the simulation, as well as a probability distribution of estimates of net present value across all years. The distribution of results for each portfolio can be compared to the distribution of results for the other portfolios. The portfolios can also be summarized and compared in terms of expected value and risk premium. The expected value of costs for each portfolio is the probability-weighted average cost of operating the NWE system across all scenarios considered in the analysis. The risk premium is the probability-weighted average of costs above the expected value (mean value). That is, the risk premium is defined as the average cost across all scenarios where the estimated cost is greater than the mean of all scenarios. For both the expected value and the risk premium calculations, the final results are summarized in terms of net present value across the 20-year planning horizon.

Detailed Outputs: A full system dispatch for each portfolio is performed for each year of each scenario, and at an hourly time step. These results can then be rolled up to annual summaries, by adding results over all hours within the year (or breaking out into high-load or low-load periods). Expected values are computed by calculating the probability-weighted average of the results across all scenarios developed for the evaluation. The primary detailed reports include:

- Net Position Report: Contains the annual generation of each generating resource, total load obligations, and net position between total system generation and load.
- Generating Stations Report: Contains detailed dispatch results for each generation resource, including generation output, capacity factor, fuel consumed, revenue and key operating cost elements (fuel, emissions, variable O&M).
- Portfolio Supply Costs Report: Includes annual portfolio-level results for market purchases, power sales, fixed costs and operating costs for each portfolio evaluated used in the study.

B. Adequacy of NWE's Application

Based on our review of the documents provided by NWE, we believe the application and supporting documents fall short of providing the PSC with all of the information necessary to evaluate NWE's application, including information required by the Administrative Rules of Montana. This section provides an Adequacy Assessment, which evaluates the degree to which the three portfolios and the information relied on to conduct the portfolio analysis provide sufficient information for the Commission to find that the application is in the public interest. This section focuses on the following:

1. Clarifications on key inputs
2. Sources of electrical generation cost inputs
3. Adequacy of the three portfolios as a set of feasible alternatives

B.1. Clarifications on Key Inputs

Carbon

The future cost of carbon emissions, an externality not currently taxed at the State or Federal level, has a positive and materially significant impact on the value of hydroelectric assets relative to generation assets that do emit carbon. NWE's carbon price assumptions are in line with internal carbon pricing used by other investor-owned utilities (IOUs) for operational and planning purposes. We believe the Commission would benefit from a discussion of NWE's view on the risk associated with investing in carbon-emitting generation, including recent decisions and/or public statements by the company that are consistent with the carbon tax assumptions used in the 2013 Resource Procurement Plan (RPP).

The Carbon Disclosure Project (CDP) recently released results from its annual disclosure process in 2013,[13] which find that most companies covered in its report expect some form of regulatory approach to addressing climate change in the future. Furthermore, "many major publicly traded companies operating or based in the United States have integrated an 'internal carbon price' as a core element in their ongoing business strategies". CDP states that utility and energy companies in particular are the most likely to employ internal carbon pricing schemes for strategic decision-making. The CDP noted that prices for carbon penalties covered a wide range from US $6-$60 per metric ton of carbon and cited $20 per ton as the average carbon price among utilities in North America.

Weighted Average Cost of Capital (WACC) Assumed in the Analysis

The WACC is an estimate of the rate of return a third-party buyer would have to pay on the capital used to purchase the assets. NWE assumes a WACC of 7.14 percent computed as the weighted average of the cost of equity and the cost of debt required for completing the purchase of the hydro facilities (Testimony of Brian B. Bird, p39). While we do not find the 7.14 percent value of the WACC to be unreasonable, it is 0.78 percentage points (78 basis points) below the discount rate of 7.92 percent used in NWE's 2011 RPP. All else constant, a lower discount rate results in higher calculated NPV. A brief discussion of the conditions (seemingly in the bond and equity markets) that led to this reduction between 2011 and 2013 would be beneficial.

[13] CDP. *Use of Internal Carbon Price by Companies as Incentive and Strategic Planning Tool.* December 2013. https://www.cdp.net/CDPResults/companies-carbon-pricing-2013.pdf

B.2. Sources of Electrical Generation Cost Inputs

Costs considered in the analysis (see Table 5-8 of the 2013 RPP) include capital costs, fixed O&M costs, variable O&M costs and heat rate. NWE does not provide sources of the cost information for the hydro or other generating assets, making it difficult to assess if these costs are reasonable.[14] The RPP is also not clear as to whether the costs associated with the hydro facilities enter the portfolio analysis as fixed values or as stochastic values drawn from a distribution developed from historical cost data. This distinction matters because the estimates of the "risk premium" presented in Volume 1, Chapter 6 show that the hydro portfolio has a substantially lower risk premium than the other two portfolios. If the projections of costs for the hydro portfolio are based on fixed values (i.e., is deterministic), this may explain at least some of the difference in the risk premium between the alternative portfolios.[15]

B.3. Adequacy of the Three Portfolios as a Set of Feasible Alternatives

The 2013 Resource Procurement Plan (RPP) submitted by NWE evaluates three alternative portfolios: (1) NWE's current portfolio as a base case, (2) a refined version of the preferred *combined cycle combustion turbine* (CCCT) option from the 2011 RPP, and (3) the acquisition of PPL's hydroelectric facilities. The 2013 RPP states, "These three scenarios bracket the full range of portfolio compositions contemplated in the 2011 plan."[16] NWE, however, provides no supporting documentation showing how these three portfolios bracket the full range of the 60 portfolios considered in the 2011 RPP.[17]

Administrate Rule of Montana (ARM) 38.5.8228 (2.c and 2.d) states:

c. *Testimony and supporting work papers describing the resource and stating the facts (not conclusory statements) that show that acquiring the resource is in the public interest and is consistent with the requirements in 69-3-201 and 69-8-419, MCA, the utility's most recent long-term resource plan (as modified by (2)(a)), and these rules;*
d. *Testimony and supporting work papers demonstrating the utility's estimates of the cost of the resource compared to the cost of each alternative resource the utility considered and all relevant functional differences between each alternative*

We do not believe the application or supporting documents provide all of the facts and related information necessary for the PSC to reach the conclusion to approve the acquisition of the hydro facilities into the rate base. This is not to say that we believe that the hydro facilities should not be added to the rate base, but rather that NWE is asking the Commission to make such a determination based on conclusory statements and not on the comparative cost information from the alternative scenarios, required in ARM 38.5.8228.

We do not believe that NWE needs to conduct a thorough portfolio analysis in PowerSimm on each of the alternative portfolios considered in the 2011 RPP in order to provide the PSC with the information

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[14] Joseph Stimatz testimony includes projected annual costs for the hydro facilities, seemingly obtained from PPL. It is unclear if these are the same costs that were included in the portfolio analysis conducted in PowerSimm.
[15] It is also not clear if the costs associate with the CCCT and current portfolios enter the analysis as fixed. However, the costs associated with these generating resources are likely less uncertain than the costs associated with the hydro facilities.
[16] Electricity Supply Resource Procurement Plan, December 2013, Vol. 1, Chapter 1, page 1-3, paragraph 3
[17] See Volume 1, Chapter 5 of the 2011 RPP for descriptions of the 60 portfolios.

required in ARM 38.5.8228. However, we do believe it is necessary for NWE to either conduct analysis in PowerSimm on a small number of additional alternative portfolios or describe in detail why considering such additional portfolios would not be competitive against the hydro portfolio and, therefore, need not be considered.

The additional alternative generation technologies that we believe NWE should address in its application and/or 2013 RPP include:

Simple Cycle Combustion Turbine (SCCT): The operating costs of SCCT generation are likely too high for it to be an alternative to the acquisition of the hydro facilities for meeting baseload demand. However, one or more SCCT could be part of a portfolio that also includes additional baseload generation from sources such as coal, wind, gas or biomass, with the SCCT serving to meet future peak demand with owned capacity. The 2013 RPP states that there is limited capacity available in its gas pipelines to supply a peaking generator, especially as gas loads to customers peak during winter. It is unclear whether such supply constraints will need to be resolved with or without the acquisition of the hydro facilities.

Supercritical Coal: A supercritical coal plant operates the steam cycle at a higher temperature than traditional subcritical plants, resulting in greater efficiency in electricity production and lower CO_2 emissions per MWh of electricity produced. While supercritical coal may be a potential option for baseload duty, it is not without risks associated with permitting (both federal and state), possible future carbon taxation and construction costs.

Integrated Gasification Combined Cycle (IGCC): In IGCC generation, a carbon-based feedstock such as coal and/or biomass is gasified and the resulting gas is used as the fuel for a CCCT generator. The 2011 RPP notes that this type of generation *strictly for energy production* is rare in the U.S. and that the level of CO_2 (about 0.8 tons) produced per MWh of generation, which while below the level of a traditional coal plant, is still greater than a gas CCCT generator.

Wind: NWE has invested heavily in wind generation. At about a 39 percent capacity factor, Montana has a substantial wind resource. Capital costs for wind generation is about $1,500 per installed kW, which is lower than for hydro. Moreover, like hydro, wind is a non-carbon-emitting resource with low variable cost. Nevertheless, among the potential impediments for additional wind generation may be siting, transmission, reliability of load, and combining with a source peak-load generation.

Woody Biomass: As is noted in the 2011 RPP, combustion of woody biomass may be able to play an important role in providing NWE with sustainable electrical generation. While the potential scale of biomass-generated electricity is well below that of the hydro acquisition, the 2011 RPP notes estimates of sufficient fuel to supply a 15 MW to 20 MW generator in each of five sawmills located within NWE's service territory. Depending on how one accounts for carbon emissions, biomass generation may or may not be considered carbon-neutral.

ARM 38.5.8228 is clear that it is not sufficient for NWE to simply conclude that acquisition of the hydro facilities is in the public interest without further explanation. We believe that NWE should either (a) demonstrate through portfolio analysis that purchase of the hydro facilities is better for ratepayers than pursuing investments in these alternative sources of electrical generation, or (b) clearly explain why purchase of the hydro facilities results in a better outcome for ratepayers (i.e., is in the public interest) than investment in these alternative technologies.

Finally, we again want to emphasize that the administrative rule is clear: the application to acquire the hydro facilities must be supported by work papers demonstrating NWE's estimates of the cost of the hydro facilities compared to the cost of each alternative resource the utility considered, and all relevant functional differences between each alternative. From our review of the 2013 RPP, application for the hydro purchase, and associated testimony and exhibits, we do not believe NWE provides the Commission with the clear, concise information required in ARM 38.5.8228. Specifically, we believe that for each alternative portfolio, NWE should provide a similar NPV analysis as Mr. Stimatz provided for the hydro acquisition in Exhibit 1 of his testimony. The NPV analysis of each of the portfolios would be a complement, not a substitute, for the analysis NWE conducted using PowerSimm.