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INTEGRATED RESOURCE PLAN
REVIEW REPORT

2019

OCTOBER • 2020

BALANCING OUR ENERGY NEEDS • TODAY AND TOMORROW

SAFE HARBOR STATEMENT

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1. Introduction and Background

The *2019 Integrated Resource Plan Review Report* (*IRP Review Report*) is the culmination of six weeks of comprehensive study of Idaho Power's resource planning practices and modeling associated with the 2019 IRP cycle. In the sections below, Idaho Power details the four-step review process undertaken to deconstruct and examine the foundational elements of the IRP analysis—including model inputs and assumptions, data import, model system settings, model verification and validation, and model outputs—and the actions taken to resolve identified issues. The document, however, stops short of delving into the company's actual IRP analysis and findings. As such, this report should be treated as a prologue to Idaho Power's ultimate Integrated Resource Plan in the 2019 cycle, the *Second Amended 2019 IRP*.

Idaho Power embarked on this review following the discovery of issues that required further analysis. As a result, the 2019 cycle has been more circuitous than a typical IRP cycle, largely due to the introduction of modeling tools that Idaho Power was using for the first time. The history of the 2019 IRP is detailed below and offers important context around the events that led to the IRP review:

- On June 28, 2019, Idaho Power Company filed its original *2019 IRP* with the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC). At the recommendation of Idaho Power's Integrated Resource Plan Advisory Council (IRPAC), the company for the first time used a Capacity Expansion Modeling (CEM) approach to build and optimize alternative portfolios for the IRP. Specifically, the company employed the Long-Term Capacity Expansion (LTCE) tool in AURORA, which allows for portfolios to dynamically adjust based on the impacts of new capacity additions and other factors.

- Subsequent to the initial filing, Idaho Power discovered that the LTCE model optimized portfolios for the entire Western Electricity Coordinating Council (WECC) region, but not necessarily for Idaho Power's system in particular. For this reason, on July 19, 2019, the company notified the Commissions of the need to perform supplemental analysis to ensure that the IRP yielded a least-cost, least-risk solution specific to IPC's service area, and asked that the Commissions refrain from adopting a procedural schedule until an amended IRP could be filed.

- On January 31, 2020, Idaho Power filed its *Amended 2019 IRP* and identified eight modifications to the original IRP, including implementation of a new manual modeling step to ensure that the LTCE results yielded the best possible economic and reliability outcomes for Idaho Power's system and its customers. Importantly, these changes resulted in only two modifications to the company's near-term Action Plan associated with the IRP Preferred Portfolio: 1) The removal of the Franklin Solar facility, and 2) The addition of 5 megawatts (MW) of demand response was moved from 2026 to 2031.

- On May 29, 2020, the company provided a correction to the IRP related to the costs associated with the Jim Bridger Power Plant (Bridger). The need for this correction was identified while preparing a response to a discovery request in a separate docket before the IPUC. Upon review, it was discovered that certain Bridger-related costs had inadvertently been excluded from portfolios in which a Bridger unit was exited prior to the existing shutdown date of 2034. This correction required the replacement of seven pages in the company's *Amended 2019 IRP* but did not impact the company's recommendation of the Preferred Portfolio.

- In June 2020, the company identified an issue in the *Amended 2019 IRP* related to the modeling cost treatment of its coal plants at which point the company asked the IPUC and the OPUC for additional time to conduct a comprehensive review of the IRP modeling process to ensure the accuracy of the 2019 IRP.
- The company filed a motion to suspend the 2019 IRP with both Commissions on July 1, 2020. Later that month, on July 31, 2020, the company provided an update on the review process and offered October 2, 2020, as the date to submit its final IRP, the *Second Amended 2019 IRP*, along with the full documentation of the review process in the form of this *2019 IRP Review Report*.

In the sections below, Idaho Power details each step of the review process, the review outcomes, and actions taken to resolve identified issues with the IRP process. While the conditions were not ideal, Idaho Power is grateful for the opportunity to conduct such a thorough investigation of its approach and practices related to the IRP. The outcome of this review not only ensures the validity of the 2019 IRP, but also offers valuable lessons and insights that can be applied to future IRPs.

2. IRP Review – Objectives, Methodology, and Outcomes

Idaho Power conducted a comprehensive review to deconstruct and examine all aspects of the 2019 IRP analysis, from model inputs to model outputs. To accomplish this review, the company formed a team (IRP Review Team) of subject matter experts from its Planning, Engineering & Construction, Power Supply, and Finance departments. Additional support and consultation were provided throughout each step of the process by members of the company's Internal Audit and Regulatory Affairs departments to ensure a consistent and methodical review.

The company performed a four-step evaluation of the IRP process. Step I included identification of key IRP inputs, sources and input-related assumptions. Step II involved evaluating the manner in which key inputs were entered into the AURORA model. Step III involved a comprehensive review of the system settings applied within the AURORA model. Step IV included validation of the AURORA model outputs to ensure results were reasonable/expected with respect to each of the key inputs.

2.1 IRP Review Objectives

The company identified several objectives for the 2019 IRP review:

- Provide clarity around the entire IRP development process

- Verify the accuracy and modeling of key inputs
- Validate model outputs
- Make processes more visible across the company
- Create consistency in the way each step is performed
- Identify appropriate and efficient resolutions for any identified issues
- Ensure compliance with industry standards and regulations

This review process provides increased transparency into the complexities of IRP development. Lessons learned from this review were not only applied to the 2019 cycle but can be used in the development of future IRPs to ensure the process is more efficient, transparent, and accurate.

2.2 IRP Review Process and Methodology

As described above, the company performed a four-step evaluation of the IRP process. Detailed below are the specific actions taken within each step.

Step I - Input Data and Source Review

In order to conduct a full examination of the multitude of inputs used in the IRP process, 11 sub-teams were formed, each with appropriate subject matter experts, to examine individual categories of AURORA model input. The sub-teams included the following:

- Forecast inputs for natural gas (sub-team 1)
- Forecast inputs for the hydrologic system and stream flow conditions (sub-team 2)
- The company's load forecast (sub-team 3)
- Forecast inputs for coal costs as well as operating parameters and cost inputs related to the company's coal units (sub-team 4)
- Operating parameters and cost inputs related to the company's existing natural gas plants (sub-team 5)
- Inputs related to co-generator & small power producers and PURPA contracts (sub-team 6)
- Demand-side inputs related to demand response and energy efficiency programs (sub-team 7)
- Transmission system-related inputs (sub-team 8)
- Transmission system inputs related to the B2H project (sub-team 9)

- Financial inputs and future supply-side resources related to items such as the Weighted Average Cost of Capital, fixed and variable operations and maintenance (O&M) costs, property tax treatment, and modeled future supply-side resources (sub-team 10)
- Reliability inputs related to the company's regulating reserve requirements (sub-team 11)

The sub-teams reviewed all aspects of these inputs, including cross-verification against source materials, examination of supporting models that produce AURORA input data (e.g., two hydrologic and streamflow models), review of regulatory decisions and orders that determined specific AURORA input treatment, and evaluation of internal methodologies and processes for developing Idaho Power-specific data (e.g., the company load forecast).

The process for validating each key input was unique and is described in Section 5 of this report. The company also used process mapping (or flowcharting) of key IRP inputs to provide insight into the complex IRP development via a visual representation. A flowchart for each key input shows how each input is treated and evaluated in the IRP process and also shows existing relationships between the input and other inputs and/or stages of the IRP process. These flowcharts are located at the end of each input sub-section in Section 3.

To complete Step I of the review process, the input sub-teams determined whether their specific input(s) had been treated appropriately or whether an adjustment was necessary. If the input was determined to be reasonable, the sub-team moved to Step II of the review. If the input required adjustment, the issue was documented, and a method of correction was identified and conducted to resolve the issue. Additionally, sensitivity analyses were performed to determine the magnitude of identified adjustments, individually and collectively (see Step IV of the review process for more detail).

Step II – Feeding Data into the Model

In Step II, the IRP Review Team examined the ways in which the above inputs are incorporated into the AURORA model. This step involved validating any necessary data transformations or conversions to make the inputs "model ready." For instance, some inputs must be converted from one unit to another to meet AURORA specifications. The IRP Review Team reviewed export files of input data within the AURORA model and reconciled it to information gathered in Step I. This reconciliation of the input data contained within the AURORA model to the source files ensured that any conversions and transformations were conducted properly, and that data fed into AURORA were accurate and consistent with the information provided by each sub-team.

Step III – Model Settings and Processing

In Step III, the IRP Review Team analyzed how AURORA treats data within the model itself—referred to as modeling logic. For this step, the company's modeling experts assessed the AURORA system settings to ensure that data within the model were interacting in a logical manner and consistent with Idaho Power's knowledge of its own system and resources. In addition, the Review Team consulted with Energy Exemplar, the developers of the AURORA model, for guidance on specific topics.

Step IV – Output Review

Finally, in Step IV, the IRP Review Team examined the AURORA model outputs to ensure the model was producing logical and consistent results. Within this step, if the sub-teams determined the output required further evaluation, additional work was performed to validate model operations as necessary. For identified adjustments from Steps I through III, sensitivity runs were completed to determine their ultimate impact on model outputs. These sensitivities compared the input data used in the *Amended 2019 IRP* and its associated results to the IRP Review Team's model run results from adjusted model inputs. The results of those sensitivity runs are discussed in Section 5.

2.3 IRP Review Outcomes

At the conclusion of the four-step review process, the company identified a range of appropriate adjustments to model inputs and treatment of data within the model. Some of these changes were identified by the company prior to commencement of the IRP review and some were discovered during the review. All identified changes, regardless of when they were first discovered, were fully evaluated in the review process. The following adjustments were identified during the review process:

Coal Plant Inputs and Cost Treatment

The following adjustments were identified in the review of coal plant inputs and cost treatment:

- Jim Bridger Plant
    - The financial assumptions used to calculate the revenue requirement for the Bridger coal units did not match the financial assumptions used to calculate the revenue requirement for all supply-side resources requiring an update to both the fixed O&M and decommission hurdle rates.
    - In the portfolio costing, AURORA truncated fixed costs at the point a Bridger unit is shut down, resulting in avoided O&M and forecasted capital additions. As a result, the remaining net book value of the unit at the time of its exit must be added back to the total portfolio cost.
    - In the remaining net book value added back to the total portfolio cost, common facility costs were truncated for Bridger units that retired early. As a result, the truncated common facility costs must be included in the remaining net book value added back to the total portfolio cost.
    - The fixed cost rates for Bridger Unit 4 were inadvertently referencing the table of fixed costs for Bridger Unit 3 within AURORA.
    - Idaho Power's share of the variable O&M costs associated with the Bridger units should have been modeled as one third of the total projected costs.

- North Valmy Plant
    - The financial assumptions to calculate the incremental revenue requirement for Valmy did not match the financial assumptions used to calculate the revenue requirement for all supply-side resources.
    - The Valmy fixed O&M rate needed to be updated to adequately capture savings associated with a shutdown of Unit 2 prior to 2025.
- Bridger, Valmy and Boardman Variable O&M
    - The variable O&M rates for Bridger, Valmy, and Boardman should have been input as a nominal 2012 amount and escalated to a 2019 amount rather than reflected as a 2019 nominal amount, as per the AURORA model input requirements.

Natural Gas Inputs

Three adjustments were identified in the review of the natural gas inputs:

- Natural Gas Transport Costs: Variable transport costs were inadvertently excluded in the model. This relatively small cost stream was reviewed for accuracy and added to the natural gas input costs.
- Natural Gas Peaker Plant Start-Up Costs: The maintenance costs associated with natural gas peaker plants were captured only as a variable cost applied directly to the runtime of the unit. Startup costs were not included, which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected. After identifying the issue, startup costs were entered, resulting in a reduction in peaker dispatch and more accurately reflecting a logical and expected outcome.
- Langley Gulch Ramp Rate: The ramp rate for the Langley Gulch natural gas plant was set for 100 percent. Upon review, this rate was reduced to 60 percent to better reflect actual plant operations.

Demand Response

In the review process, Idaho Power tested an alternative approach to modeling demand response (DR). In prior versions of the 2019 IRP, expanded DR programs were modeled such that dispatch of said programs would only execute when Idaho Power's resources were in deficit. That is, expanded DR was being treated as a last-resort resource. In the IRP review, Idaho Power opted to treat DR as a resource to offset peak load. While the prior approach was not incorrect, the revised approach is more consistent with the way Idaho Power's DR programs work in practice.

Financial Assumptions and Future Supply-Side Resources

Two adjustments were identified related to the financial assumptions of new resource additions in AURORA:

- Property tax rates were outdated. Upon review, the rates were adjusted to reflect information available when the 2019 IRP analysis was originally performed.
- Annual insurance premium rates inadvertently reflected the wrong decimal place value. This issue was corrected during the review process.

Transmission Inputs

Two adjustments were identified in the review of transmission system inputs:

- The loss and/or wheeling rates applied to some transmission lines required adjustment. Rates were adjusted and now reflect correct information.
- The following adjustments to transmission capacity were identified in the review process and have been entered into AURORA:
    - Following exit from the Boardman coal plant, available transmission capacity was understated (53 MW).
    - The Idaho Power transmission export capacity on Boardman to Hemingway was understated (85 MW).
    - Idaho to Northwest west-to-east capacity in January through May and September through December post July 2026 was understated (200 MW).
    - The transmission capacity on Bridger West was adjusted to reflect Idaho Power's ownership share.

Reliability Inputs

The following adjustments were identified in the review process:

- The solar and wind allocation factors for downward regulation referenced the upward allocation factors (RegUp). These allocation factors are now referencing downward regulation (RegDn).
- Valmy Unit 2 was modeled with the ability to provide regulation reserves, but the unit cannot provide regulation reserves. This adjustment was made, and Valmy Unit 2 is now modeled appropriately.

The IRP Review Team, having identified the above issues, ran the adjustments through select resource portfolios to determine the impact to the overall IRP results—impact was defined as the degree of change from prior results in the *Amended 2019 IRP*. The model was run separately for each individual adjustment, as well as with the collective set of adjustments. The details of each adjustment, the results of the model runs, and the identified resolution of each adjustment is further described in Section 6 of this report.

3. MODEL INPUTS AND VERIFICATION

As described previously, a total of 11 sub-teams were formed, each with appropriate subject matter experts, to examine individual categories of AURORA model input data. In Step I of the review process, each of the sub-teams conducted deep-dive interviews with those at Idaho Power responsible for preparing the data for use in AURORA. Company subject-matter experts helped with the evaluation of a key input, its assumptions, and sources. In Step II of the review process, the sub-teams conducted interviews with members of the company's IRP planning team to analyze how each key input is fed into the AURORA model, and gain an understanding, if applicable, of any necessary changes or conversions that were made to the data inputs to make them model ready.

The following section details the review process performed in Steps I and II for each of the sub-teams. A flowchart (or process map) accompanies each key input.

3.1 Natural Gas Price Summary

3.1.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs related to the natural gas price forecasts, as well as the final and comprehensive natural gas price forecast, which combines the forecast natural gas prices and the associated forecast of fuel transportation costs. The following summarizes the inputs and key assumptions for natural gas:

Forecasted Gas Rate Sources

The company uses three natural gas price forecasts in the IRP:

1. Platts' Henry Hub natural gas price forecast
2. The U.S. Energy Information Administration's (EIA) Henry Hub low oil and gas forecast
3. EIA's Henry Hub reference mid gas price forecast.

Transportation Costs

In addition to the price forecast, the company adds transportation costs specific to bringing gas from a regional hub to Idaho Power's resources. Transportation cost components are as follows:

1. Flat transport cost – Tariff costs fluctuate from year to year and are difficult to predict into future years, so the current rate is assumed for the next 20 years.
2. Transport variable costs – These costs were also assumed at the current tariff rate since costs fluctuate from year to year and are difficult to predict into the future.
3. Transportation expansion costs based on existing available pipeline capacity and generation – It was determined that after roughly 600 MW of generation it would be

necessary to diversify natural gas supply to the Rocky Mountain supply region. Currently, gas is sourced exclusively from Canadian supply and the path from the Rockies to Idaho is fully subscribed, meaning a pipeline expansion would be necessary.

4. Monthly shaping of gas forecasts using Platt's five-year forecast.

For the 2019 IRP analysis, the company utilized three natural gas price forecasts, each prepared by a third-party entity (i.e., Platts and EIA). Because these inputs are prepared externally, it was determined that no further verification was necessary beyond ensuring that the values in the forecasts were appropriately and accurately reflected in the model input tables.

The company utilized data from the Northwest Pipeline tariff to derive the fixed and variable natural gas transport costs used in the 2019 IRP. As part of the review, the company's forecast of costs was reconciled to the Northwest Pipeline tariff.

Transportation expansion costs used in the 2019 IRP were provided by Northwest Pipeline. Idaho Power was provided with an estimate for an expansion of the pipeline from Northwest Pipeline's Rocky Mountain supply region to Idaho. The estimated pipeline expansion costs were then modeled to determine the cost for four natural gas resources: Combined-cycle combustion turbine (CCCT), single-cycle combustion turbine (SCCT), reciprocating engine with a nameplate of 111.1 MW, and reciprocating engine with a nameplate of 55.5 MW.

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, the Natural Gas Price Sub-Team identified no concerns with the natural gas price inputs to the 2019 IRP.

3.1.2. Transferring Inputs into AURORA

To ensure that the natural gas price data prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the natural gas price input data within the AURORA model and tied those inputs to the various source files prepared by the responsible Idaho Power business unit. During this process, it was determined that the natural gas price inputs prepared for the 2019 IRP reconciled to the natural gas price inputs within AURORA, with the exception of variable transport costs, which had not been loaded into AURORA. This adjustment was made, and a sensitivity analysis was performed. The results of the sensitivity analysis are provided in Section 6.3.

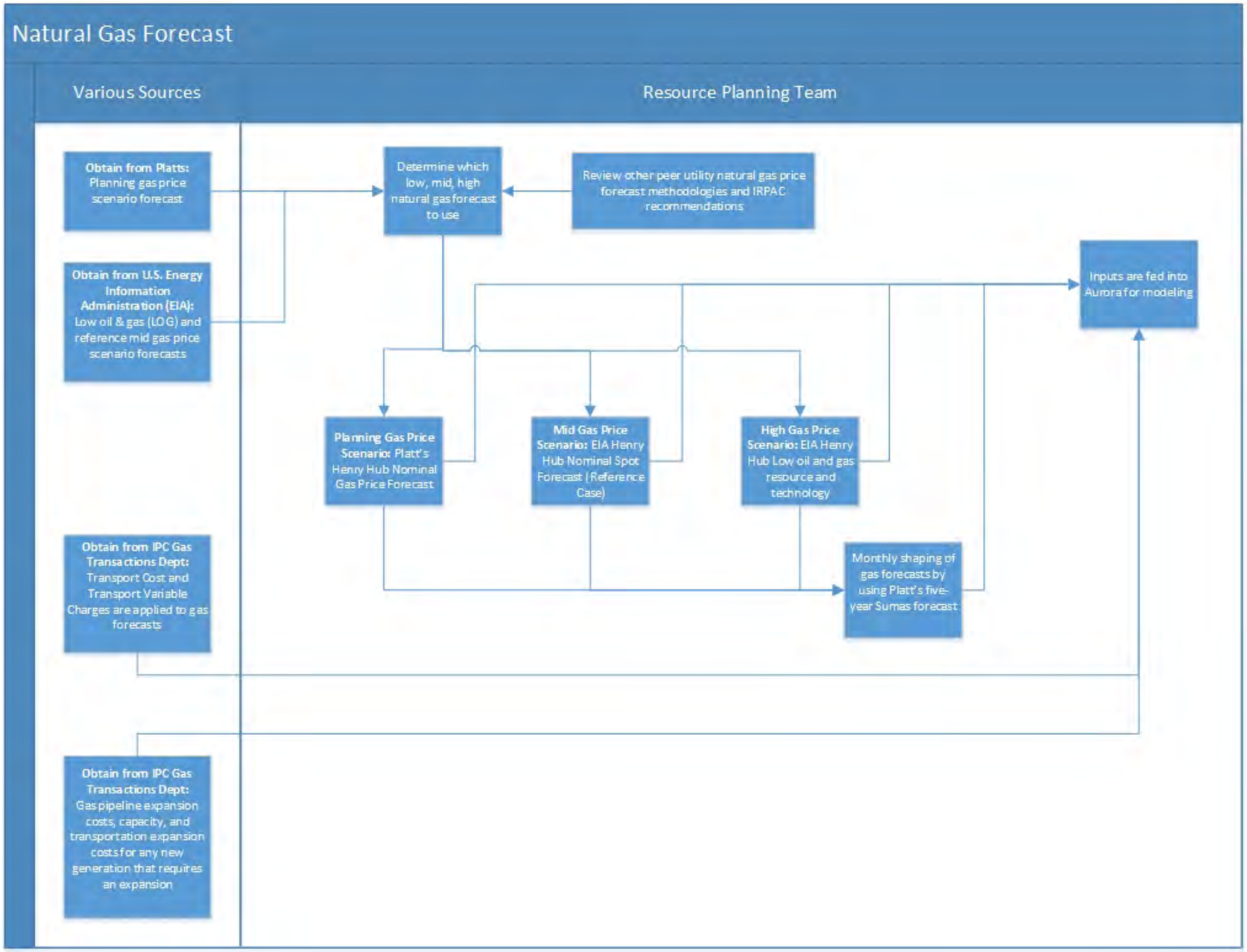

Figure 3.1 Natural Gas Price Process Map

3.2 Hydrology, Stream Flow Forecast Summary

3.2.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs associated with the company's hydrology and stream flow modeling, which is used to develop the forecast of hydropower generation distribution for the company's hydroelectric resources. The following summarizes the inputs and key assumptions:

Water Flow

1. Aquifer discharge levels are present-conditioned to 2009, and any changes can be superimposed on the current levels of aquifer discharge to the Snake River.

2. Variability exhibited by natural flow conditions from 1928-2009 are representative of future variability.

3. Diversion patterns have not changed significantly since 2009.

4. Current reservoir management practices will continue into the future.

5. The Enhanced Snake Plain Aquifer Model (ESPAM), run in "superposition mode," is used to reflect the incremental change in streamflow in the Snake River due to various aquifer management practices (e.g., recharge, groundwater pumping reductions, system conversions).

Future Assumptions Based on Water Flow

1. Target Control Analysis: Idaho Power's Atmospheric Sciences department performs a target control analysis to determine weather-modification impacts from the collaborative cloud seeding program.

2. Weather Modification Reach Gains: Operations Hydrology performs modeling that translates the target control analysis, which is essentially an average increase in winter season precipitation, into an incremental surface water streamflow benefit at various locations throughout the Snake River. This incremental benefit is added to the base planning model.

3. Reach Decline Trend Analysis: Operations Hydrology applies statistical tests to three reaches (Blackfoot to Neeley, Milner to Lower Salmon, and Lower Salmon to King Hill) to determine if a significant trend in aquifer discharge to the Snake River is present. If a trend is present, then it is extended through the IRP planning horizon to account for likely changes that the aquifer will experience over that time frame.

4. Surface Water Coalition (SWC)-Idaho Groundwater Appropriators (IGWA) Settlement Agreement: In 2015, a settlement between the SWC and the IGWA was reached regarding groundwater user impact to holders of senior surface water rights. The settlement agreement laid out key targets that will alter the aquifer budget in future years. The elements of the agreement are described below:

i. Groundwater Pumping Reductions – The agreement targets a volume reduction in groundwater usage. This reduction is modeled using ESPAM, and the incremental benefit is added to the base planning model.

ii. Groundwater to Surface Water Conversions – The agreement targets a volume change due to switching groundwater irrigated land to surface water supplied land, which benefits the aquifer. This change is modeled using ESPAM, and the incremental benefit is added to the base planning model.

5. Managed Aquifer Recharge: Managed aquifer recharge observations and plans are obtained from the Idaho Department of Water Resources. The volume of recharge is modeled using ESPAM, and the incremental benefit is added into the base planning model.

Generation Forecasting

1. Generation is forecast at the 50 percent exceedance level for the planning scenario, but 70 percent and 90 percent exceedance water conditions are also developed to support sensitivity analyses related to below-normal water years.
2. The historical monthly average generation from springs, based on the last 20 years, is used as a forecast for IRP modeling.

Based on the above review of key assumptions and inputs, the Hydrology and Stream Flow Sub-Team identified no concerns with the hydro forecast input to the 2019 IRP.

3.2.2. Transferring Inputs into AURORA

To ensure the hydrology and streamflow data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the hydro input data within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. During this process, a difference was identified between the source files and the AURORA input during leap years. Those differences, the review team concluded, were appropriate modifications of the input data to account for additional hydro generation hours every four years from the additional day in each leap year. Additionally, a difference was discovered between the source files and AURORA input for Brownlee, Oxbow, and Hells Canyon hydro facilities—collectively, the Hells Canyon Complex (HCC). The AURORA model holds reserves at these hydro facilities in accordance with NERC requirements. The data from the PDR580 hydro generation model, however, represents the monthly energy budget with no reserves held at the HCC. The noted deviation is variable by simulation month and year but averages 10 percent of the HCC energy budget being held in reserve by the AURORA model. The sub-team concluded that variations between PDR580 data and AURORA input were reasonable and also deemed the modeling of reserves in AURORA was appropriate. Based on the above findings, the sub-team identified no concerns with the hydrology and streamflow inputs into AURORA for the 2019 IRP.

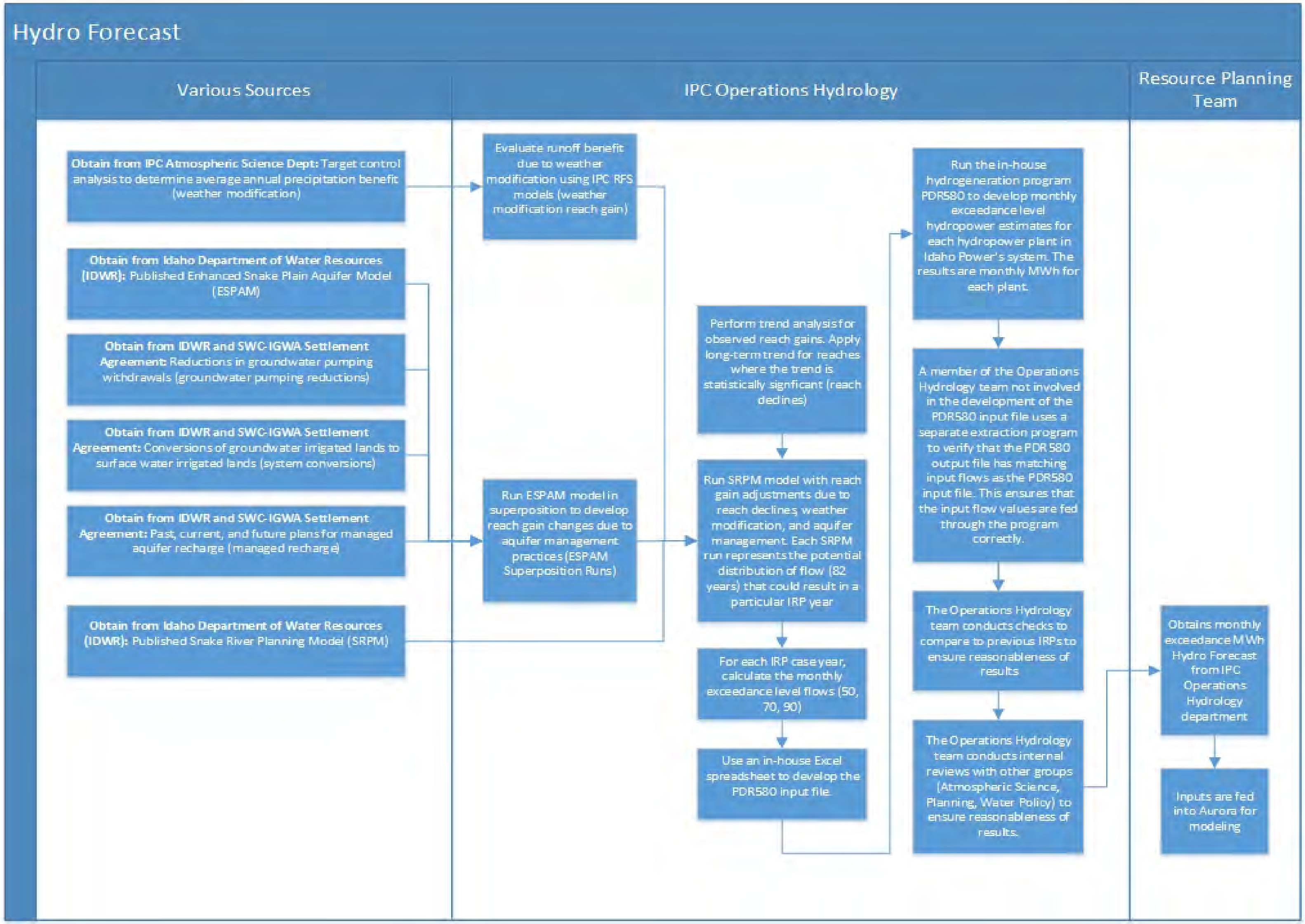

Figure 3.2 Hydrology, Stream Flow Process Map

3.3 Load Forecast Summary

3.3.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs to develop the load forecast. Although the load forecast is a complex analysis that incorporates many inputs, Step I for this input was scaled down due to a recent audit conducted by Idaho Power's Audit Services Department in the ordinary course of business. This audit involved gaining an understanding of the inputs and controls around the load forecasting process, flowcharting the process, cataloging the inputs, and mapping the inputs to validation procedures performed. This audit concluded in September 2019. Additionally, the load forecast goes through a rigorous public involvement and review process, during which time inputs and assumptions can be questioned by both internal and external stakeholders. Therefore, the Load Forecast Sub-Team determined that thorough analysis of the load forecasting process was already performed. Nevertheless, key assumptions, inputs, and sources are provided below in the interest of clarity and transparency. The following summarizes the inputs and key assumptions:

1. The company uses several primary sales models as the basis of the load forecast, which looks out over the same 20-year forecast period as the 2019 IRP. These forecast models are linked to major customer classes.

2. The residential sales forecast utilizes an end-use framework and identifies temperature-sensitive load (e.g., appliances), as well as home size. The appliances and saturations of such are calibrated to the company's service territory, as determined by Idaho Power's saturation survey administered by the Energy Efficiency Department. Appliance efficiencies and energy use per appliance are determined from shipment and forecast data compiled by Itron, which is developed from the EIA data (e.g., the Annual Energy Outlook) for the US by census region. Residential non-temperature sensitive load is identified using the same method.

3. The commercial, industrial, and irrigation sectors use a more classic econometric regressions framework. The cohort of commercial and industrial customers is further disaggregated and modeled by primary business function. Unique explanatory variables are selected for each of the modeled business functions. These explanatory variables that are used are typically economic in nature and lean on macro-economic forecasts developed by Moody's Analytics. Adjustments are assessed for each forecast period, typically using residual analysis.

4. Other key inputs to the process are customer growth (hinged on Moody's Analytics household stock forecast data), weather data (using identified National Oceanic and Atmospheric Administration (NOAA) data collection sites at Boise, Twin Falls, Ontario, McCall, Pocatello, and Ketchum), electricity prices from Idaho Power's assessment of rate base and short term fuel costs (conducted by the Regulatory Affairs and Strategic Analysis Departments), natural gas price from the long-term customer price forecast from Intermountain Gas and the natural gas price forecast (see Section 3.1 for the natural gas input assessment).

The key inputs for the load forecast come from many sources. Inputs and the process of data collection and analysis are detailed below:

1. Introduction – The energy sales and load forecast of future demand for electricity within the Idaho Power service area covers a 20-year period and is the company's estimate of the most probable outcome for sales growth during the 20-year planning period.

2. Pre-Modeling Activities

    a. Pricing Forecast

        i. Natural Gas Price Forecast – The Load Forecasting team obtains historical natural gas price and usage information from Intermountain Gas Company (IGC) and natural gas price forecasts (EIA and Platts) and creates the natural gas price forecast. The Load Forecasting team applies economic deflators from Moody's Analytics to arrive at real prices that have been adjusted for inflation. The price forecast is reviewed by the Load Research and Forecasting Manager and is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling.

        ii. Electricity Price Forecast – The Load Forecasting team obtains projected demand response irrigation rebate values from the Energy Efficiency Program Leader, four sources of revenue by major class of forecasted electricity price from the Finance Department, and forecasted electricity price increases/decreases from the Regulatory Affairs Department. The Load Forecasting team creates the electricity price forecast using this data and then applies economic deflators from Moody's Analytics to the prices to arrive at real prices that have been adjusted for inflation. The price forecast is reviewed by the Load Research and Forecast Manager and is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling.

    b. Economic Analysis – The Load Forecasting team gathers economic data (e.g., population growth, income trends, geographic GDP trends, industry groups) from third-party resources (e.g., Moody's Analytics, Woods & Poole, and others as necessary). The team performs comparative analysis on the data obtained to determine if exceptions or deviations exist that might require disaggregation of the data or evaluation of additional third-party resources. The economic data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

    c. Customer Count Forecast – The Load Forecasting team obtains growth data from Moody's Analytics, such as housing stock, mortgage rates, household data, as well as historical active customer counts. This data is used to forecast customer counts for each customer class in Idaho Power's service area. The customer count data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

d. Weather Updates – The Load Forecasting team obtains monthly kilowatt-hour (kWh) usage data and historical weather data from NOAA. Usage data is normalized using the NOAA data and is input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

e. Energy Efficiency/Demand Side Management (DSM) Forecast – The Load Forecasting team obtains the Itron SAE models with DSM assumptions, the Energy Efficiency/DSM forecast from the Energy Efficiency Department, and the third-party DSM potential study performed by Applied Energy Group (AEG). The Itron SAE models are customized with inputs more specific to Idaho Power's service area, based on the forecast provided by the Energy Efficiency Department. The information provided by the Energy Efficiency Department is compared to the AEG potential study to determine whether adjustments to the forecast are necessary. The data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

3. Energy (or Sales) Forecast by Customer Class

a. Net Metering Impact Adjustment – The Load Forecasting team obtains historical net metering customer counts for residential and commercial customers, as well as the "Customer by Rate" SQL query to determine the energy impact by month for customers that have switched to net metering. Using polynomial equations and rate-of-change analysis, the projected net metering customer counts are multiplied by the projected energy impact. The results are reviewed by the Load Research and Forecasting Manager, input into the Oracle Express database, and then subtracted from the residential and commercial sales forecasts.

b. Electric Vehicle (EV) Usage Forecast – The Load Forecasting team obtains vehicle registration data from the Idaho Transportation Department (ITD), which the team uses to complete a regression model that forecasts EV usage for residential and commercial customers. The results are reviewed by the Load Research and Forecasting Manager, input into the Oracle Express database, and then incorporated into the residential and commercial sales forecasts.

c. Residential Sales Forecast – The Load Forecasting team obtains the Residential SAE model from Itron for the Mountain Region geographic area, as well as the most recent Idaho Power service area saturation surveys from the Customer Research Department. The Itron SAE model is customized with inputs more specific to IPC's service area based on the saturation surveys and then is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The residential sales forecast is generated based on these items as well as the results input into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager and the net metering impact adjustment and EV vehicle usage forecast from items 3a. and 3b. above are incorporated into the sales forecast.

d. <u>Commercial Sales Forecast</u> – The Load Forecasting team obtains streetlight usage data, the Commercial SAE model from Itron for the Mountain Region geographic area, and information regarding potential new large load customers from the Business Development Department. The team also determines commercial customer segmentation (e.g., manufacturing and services). The Itron SAE model is customized with inputs more specific to Idaho Power's service area, reviewed by the Load Research and Forecasting Manager, and then input into the Oracle Express database along with the streetlighting usage forecast. Output files from the database are fed into the MetrixND software for forecast modeling. The commercial sales forecast is generated based on these items as well as the results input into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager and the net metering impact and EV vehicle usage forecast from items 3a and 3b above are incorporated into the sales forecast.

e. <u>Industrial Sales Forecast</u> – The Load Forecasting team obtains information regarding potential new large load customers from the Business Development Department. The team also determines industrial customer segmentation (e.g., manufacturing and services). The industrial modeling data is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The industrial sales forecast is generated based on these items as well as the results entered into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness.

f. <u>Irrigation Sales Forecast</u> – The Load Forecasting team obtains horsepower updates from the Energy Efficiency Department. Any relevant irrigation legislation updates and aquifer updates are obtained as well. This information is entered into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The irrigation sales forecast is generated based on these items as well as the results entered into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness.

g. Special Contracts Sales Forecast – The Load Forecasting team obtains request letters sent and received by the Regulatory Affairs Department for customer-provided updates to forecasted large, special contract energy customer loads. The forecasts in the letters are compared to historical trends, and a follow-up discussion with the large energy customers occurs if necessary. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness and is included in the total system load forecast.

4. Hourly Peak-Load Forecast

    1. Conversion of Billed Sales Forecasts to Calendar Sales Average Load – The Load Forecasting team obtains billed sales data from AMI and applies monthly weighting factors to the data for conversion to calendar month data. The results are reviewed by the Load Research and Forecasting Manager. Then, the residential, commercial, industrial, and irrigation billed sales forecasts are converted to calendar sales forecasts using these results. These conversions are reviewed by the Load Research and Forecasting Manager and then are provided to the Resource Planning team for inclusion in the IRP.

    2. Peak Load Forecast – The Load Forecasting team obtains a 30-year historical period of average peak-day temperatures by month and runs a regression analysis on actual historical peak-day temperatures by month versus system peaks. The team also applies a loss factor (obtained from the System Planning Department) to the calendar-converted sales forecasts. These items are used to generate the peak-load forecast, based on peak-day temperatures and average load by month. The peak-load forecast is reviewed by the Load Research and Forecasting Manager.

    3. Hourly Forecast – The Load Forecasting team obtains the aggregate system energy forecast, 30-year historical weather data, calendar composition of the forecast period, and AMI and MV90 hourly data. This data is pushed through a non-linear model framework to develop heating and cooling responsiveness using derivative analysis. The 5-degree temperature slope from this derivative analysis is leveraged into a linear regression framework. The outputs from the linear regression are input into the MetrixND software. The hourly forecast is then generated using this data and the peak-load forecast from item 4b above. The hourly forecast is reviewed by the Load Research and Forecasting Manager and then is provided to the Resource Planning team for inclusion in the IRP.

5. Public Involvement Process – The Load Research and Forecasting Manager presents the output of the forecast models to the Idaho Power Finance Department's Senior Vice President, Vice President, and Director, and incorporates any changes based on financial management's expertise into the models, as needed. The updated output of the forecast models is then presented to all Idaho Power executives. If necessary, results are reviewed again based on executive management's expertise and any necessary corrections are incorporated into the model. Updated output of the forecast models is then presented to the IRPAC. If necessary, changes based on IRPAC

feedback are incorporated into the models. After the public and stakeholder input process is complete, the load forecasts are finalized for inclusion in the IRP.

6. Load Forecasting Process Flowchart – The sub-team obtained and reviewed the load forecasting flowchart from the audit conducted by Audit Services.

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, as well as the 2019 audit performed by Idaho Power's Audit Services, the Load Forecast Sub-Team identified no concerns with the load forecast input to the 2019 IRP.

3.3.2. Transferring Inputs into AURORA

To ensure that the hourly load forecast data prepared for the 2019 IRP was correctly input into the AURORA model, the sub-team exported the hourly load data within the AURORA model and tied those inputs to the source file prepared by the responsible business unit. During this review process, it was determined that the hourly load forecast data prepared for the 2019 IRP reconciled to the hourly load forecast inputs within AURORA.

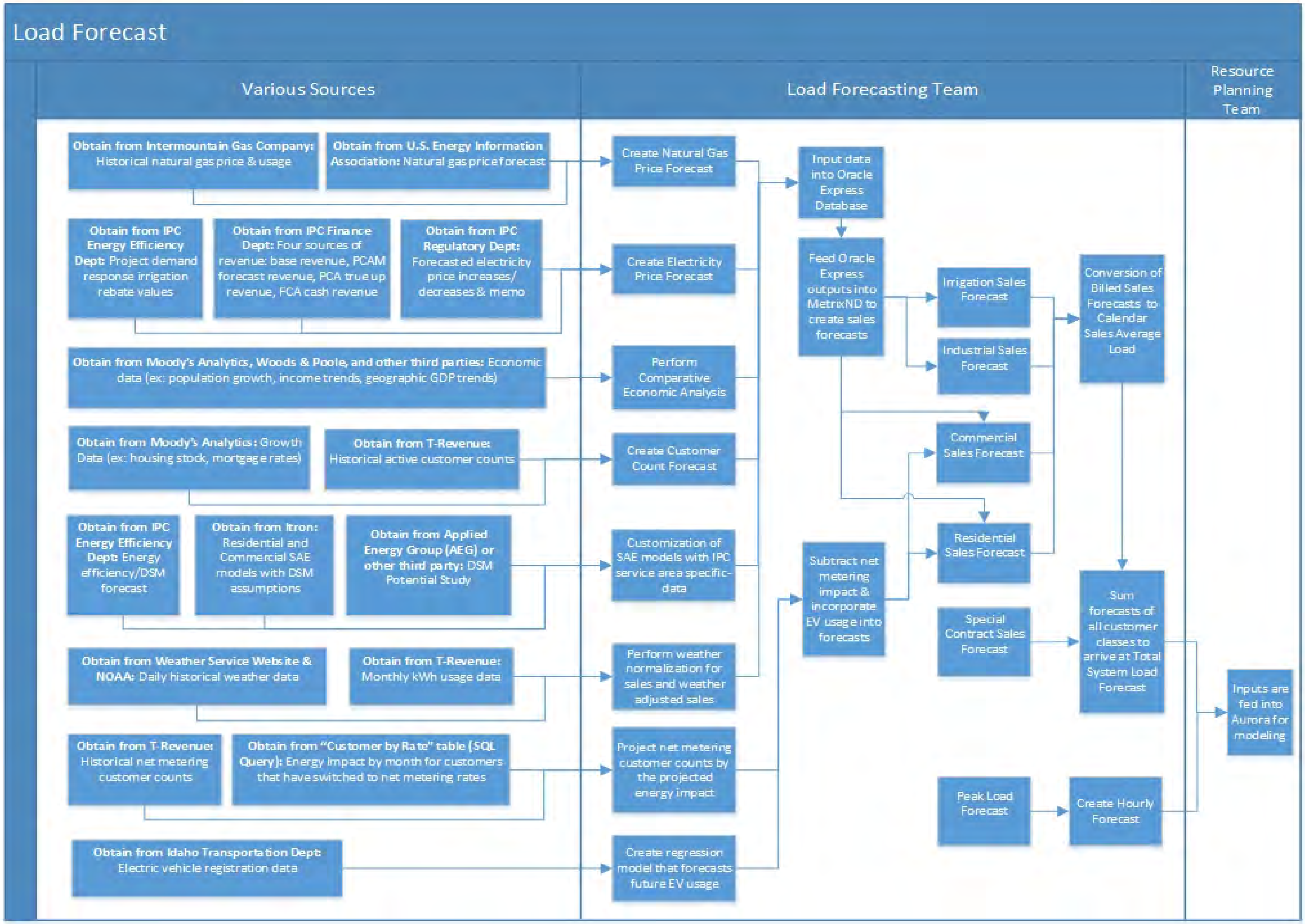

Figure 3.3 Load Forecast Process Map

3.4 Coal Plant Forecasts and Operations Summary

3.4.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, this sub-team assessed the supply-side inputs related to the company's coal units. The coal-related inputs included coal forecasts, plant operating parameters, variable O&M, fixed fuel costs, and non-fuel fixed costs. The following summarizes the inputs and key assumptions:

Coal Forecast for Bridger

1. The Bridger fuel forecast is derived from the Bridger Coal Company 2019-2028 budget, forecast third-party delivered coal prices, and volumes that are a component of the 2018 long-term fueling plan.

2. The delivered cost of Black Butte coal for the 2019 through 2021 period is based on actual contract rates plus estimated rail transportation charges. The Black Butte delivered coal price from 2021 is then escalated at 3 percent beginning in 2022, based on assumed annual increases in coal and transportation contract renewal rates.

3. Estimated rail transportation charges included in the delivered price of coal for 2019 are based on published Union Pacific (UP) rates at the time.

Coal Forecast for Valmy

4. The Black Butte mine is assumed to be the fuel source for Valmy due to the small volumes likely to be required through 2025 and the available capacity at the time the forecast was performed.

5. The delivered cost of Black Butte coal for 2019 is based on actual contract rates plus estimated rail transportation charges. The coal component of the Black Butte delivered coal price from 2020-2025 is escalated at 3 percent annually beginning in 2020, while the rail transportation component of the Black Butte delivered coal price is escalated at 4 percent annually beginning in 2020. These are the assumed annual increases in coal and transportation contract renewal rates.

6. The Nevada use tax is applied to the price of coal. The statutory rate of 6.85 percent was used.

7. Estimated rail transportation charges are based on published UP rates at the time.

Coal Forecast for Boardman

8. The fuel forecast is obtained from PGE for the remaining two years (2019 and 2020) of the plant's life.

Operating Parameters for Bridger

9. There are multiple operating assumptions for the Bridger plant that are used as an input to AURORA or used to develop an AURORA input: Overall plant average heat

rate, capacity, equivalent forced outage rate, fixed and variable O&M, mine decommissioning costs, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, minimum down time, and revenue requirements associated with existing and future investments.

Operating Parameters for Valmy

10. There are multiple operating assumptions for the Valmy plant that are used as an input to AURORA or used to develop an AURORA input: Overall plant average heat rate, capacity, equivalent forced outage percent, fixed and variable O&M, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, minimum down time, and revenue requirements associated with future investments.

Operating Parameters for Boardman

11. There are multiple operating assumptions for the Boardman plant that are used as an input to AURORA or used to develop an AURORA input: overall plant average heat rate, capacity, equivalent forced outage percent, variable O&M, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, and minimum down time.

Capturing Fixed Fuel Costs Associated with Early Unit Shutdowns at Bridger

12. There are unavoidable fixed costs associated with Idaho Power's share of the Bridger Coal Company mine through 2028 that need to be considered in all AURORA portfolios. Because these fixed costs are a component of the fuel expense, if a shutdown of a Bridger unit were to occur prior to 2028, Idaho Power needs to ensure enough coal was burned in the remaining units to sufficiently recover these fixed costs. If it is not, then the fixed cost shortfall needs to be included as an additional cost to each portfolio.

Bridger Non-Fuel Fixed Cost Forecast

13. Bridger unit-specific forecasts of non-fuel fixed costs were developed in order to adequately capture avoidable and unavoidable costs specific to portfolios that contain proposed shutdowns of units earlier than 2034. The sources of the key data used to develop the revenue requirements are the net book value of the Bridger investments at June 30, 2018, and Bridger O&M and capital forecasts provided by PacifiCorp through 2034. Idaho Power used an internal revenue requirement model (the PWorth model) to calculate the estimated revenue requirement for each Bridger unit through 2034 to determine the fixed cost inputs for AURORA. In the portfolio costing, AURORA truncates fixed costs at the point a unit is shut down earlier than 2034, appropriately reflecting avoided O&M and forecasted capital additions. The remaining net book value is also used in the LTCE modeling as the cost hurdle associated with an early exit of a unit.

Valmy Non-Fuel Fixed Cost Forecast

14. A Valmy Unit 2 forecast of non-fuel fixed costs was developed in order to adequately capture avoidable costs specific to portfolios that contain a proposed shutdown of Unit 2 prior to 2025. The sources of the key data used included the Framework

Agreement between Idaho Power and NV Energy and the resulting exit fees, O&M expenses, and capital forecasts through 2025 provided by NV Energy. Idaho Power used the PWorth model to calculate the estimated revenue requirement associated with Valmy Unit 2 forecasted investments to determine the fixed cost inputs for AURORA. As described above, fixed costs are truncated by AURORA in the portfolio costing when Unit 2 is retired prior to 2025, appropriately reflecting avoided fixed O&M and forecasted capital costs.[1]

Sub-Team Results of Step I Review

Upon thorough review and evaluation of the source files, the sub-team confirmed the coal forecasts and resulting fuel expense were modeled appropriately and accurately, and the operating parameters were supported and reasonable. In addition, the Bridger coal forecast included enough generation in each of the portfolios to cover the fixed costs of the Bridger mine or, in the alternative, the resulting shortfall cost was added to the total portfolio costs.

A number of refinements were made to the Bridger and Valmy fixed O&M rates. As discussed below in sub-section 3.10 "Financial Inputs and Future Supply Side Resources," inconsistent financial inputs were used in the PWorth model. This model computes the Bridger and Valmy revenue requirement amounts, a component of the fixed O&M weekly $/MW rate calculation, as well as the Bridger investment net book value, a component of the decommissioning hurdle rate calculation. Both are inputs in AURORA, and it was determined the rates needed to be updated (see Section 3.10). Due to the truncation of Bridger fixed costs and Bridger common facility costs once a unit is exited, it was determined that any remaining net book value of the unit at the time of its exit must be added back to the total portfolio cost. In addition, to adequately capture savings associated with a shutdown of Valmy Unit 2 prior to 2025, it was determined that the Valmy fixed O&M rate needed to be updated.

Finally, it was determined that AURORA interpreted the variable O&M rates for Bridger, Valmy and Boardman as if they were nominal 2012 amounts and escalated them to 2019 amounts. As a result of this discovery, an adjustment was required for each of the variable O&M rates. A sensitivity analysis was performed to assess the impact on portfolio costs, and the results are discussed in Section 6.3.

3.4.2. Transferring Inputs into AURORA

To ensure the coal plant operating parameters and coal fuel forecast data prepared for the 2019 IRP were correctly entered into AURORA, the sub-team exported the input data within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. The review process determined that the majority of the coal-related inputs prepared for the 2019 IRP reconciled to the inputs within AURORA, with the exception of variable O&M costs for Bridger. Per the Bridger ownership agreement, each party is billed for its proportional share of the variable cost tied to overall plant output. Therefore, Idaho Power's share of Bridger variable O&M costs should be one-third of the total projected cost. The input

[1] Please see the discussion in Chapter 1 of the *Second Amended 2019 IRP* for discussion of Valmy Unit 2 exit timing.

value within AURORA did not reflect the Idaho Power’s one-third share. As a result, a sensitivity analysis was performed with the appropriate variable O&M costs entered in AURORA. The results of the sensitivity analysis are provided in Section 6.3. Additionally, the review process identified the Bridger Unit 4 fixed O&M rate was incorrectly linked to the Bridger Unit 3 fixed O&M costs within AURORA. This link was updated in conjunction with the update to Bridger fixed O&M rates discussed above.

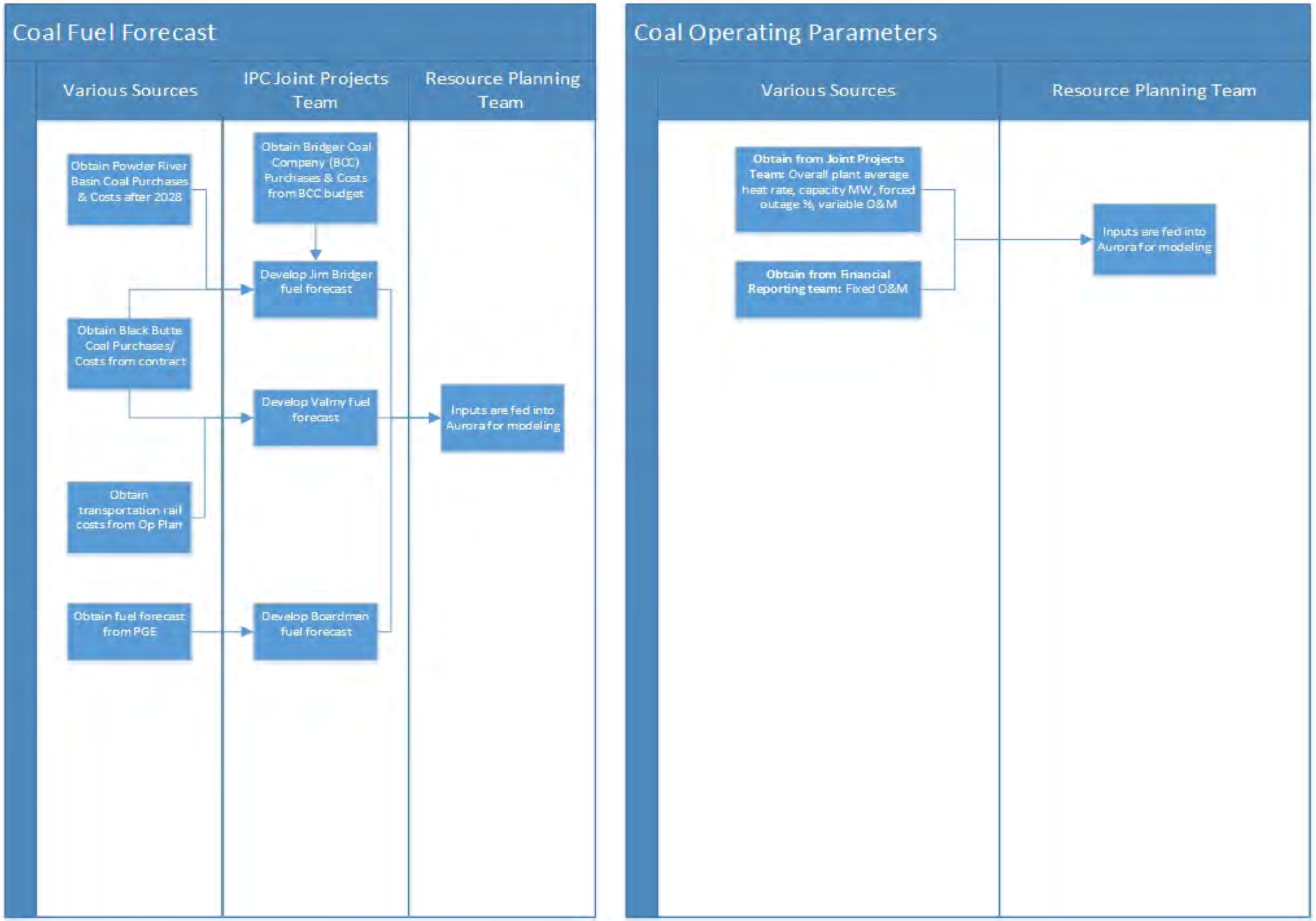

Figure 3.4 Coal Plant Forecasts and Operations Process Map

3.5 Natural Gas Plant Inputs Summary

3.5.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs related to the company's natural gas plants. The natural gas plant-related inputs included plant operating characteristics and fixed and variable O&M costs. The following summarizes the inputs and key assumptions.

The Natural Gas Plant Sub-Team, along with a company subject matter expert, evaluated the operating characteristics of each of Idaho Power's existing natural gas plants (Langley Gulch, Danskin, and Bennett Mountain) including: heat rate, capacity, capacity monthly shape, monthly variable O&M, startup costs, ramp rate, min up time, and min down time. The team noted the following inputs were pre-populated in AURORA by Energy Exemplar using publicly available information: Non-cycling dispatch price adder, minimum capacity, heat rate at minimum capacity, and emission rates.

Sub-Team Results of Step I Review

The sub-team identified two items that could have an impact on the IRP relating to plant operating characteristics:

- Natural gas plant maintenance costs associated with the peaker plants were captured only as a variable cost applied directly to the runtime of the unit. Startup costs were included in the same way (i.e., variable runtime costs), which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected.

- The ramp rate input for Langley Gulch was set to 100 percent, which does not accurately reflect actual operations of the plant. The sub-team determined that a 60-percent ramp rate would better reflect plant operations.

3.5.2. Transferring Inputs into AURORA

To ensure that the natural gas plant operating parameters prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the natural gas plant input data within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During the review process, it was determined that most natural gas plant inputs prepared for the 2019 IRP reconciled to the natural gas plant inputs within AURORA. The inputs that did not reconcile included startup costs for each of the company's natural gas peaker plants as well as the ramp rate for Langley Gulch. As a result, sensitivity analyses were performed with the appropriate natural gas plant inputs in AURORA. The results of the sensitivity analyses are provided in Section 6.3.

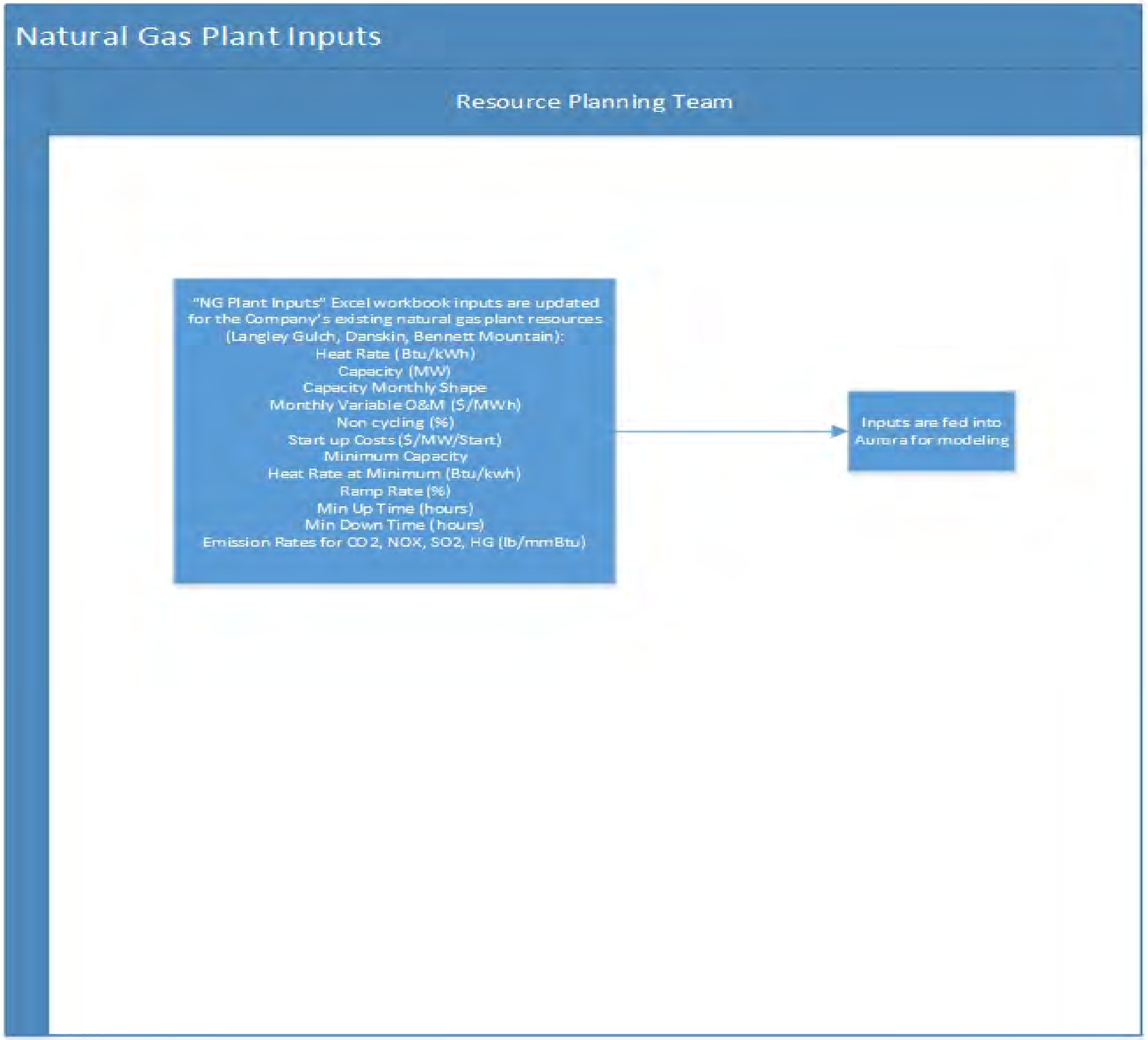

Figure 3.5 Natural Gas Plant Process Map

3.6 CSPP and PURPA Inputs Summary

3.6.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed inputs related to Idaho Power's cogeneration and small power production (CSPP) and PURPA forecast. The following summarizes the inputs and key assumptions:

Forecast Avoided Cost Rates

1. Contract rates for contracts with annually adjusted rates are forecast at the actual rate at the time of the forecast through the forecast period.

2. Current IPUC or OPUC rates for a given resource type can be used.

3. Contract rates for Power Purchase Agreements (PPA) utilize rates from the previous 12 months without escalation over the forecast period.

Forecast Generation

4. Estimated Generation: Initial contract estimates are used for new contracts, the most recent 12-month history, or the arithmetic mean of the last five years of generation. Normally, the arithmetic mean of the last five years of generation is used. Estimates can be adjusted based on knowledge of the project and resource type.

5. Included Energy Service Agreements (ESA) and PPAs: New projects are included in the forecast upon signing of a contract, as the company is legally bound to purchase power at that point.

6. All contracts are forecast to be replaced upon expiration of the existing contract except for wind contracts. The company is unable to accurately predict whether wind Qualifying Facilities (QF) will choose to invest in repowering due to several factors.

7. Average estimated generation is allocated to Heavy Load (HL) at 56 percent, unless it is determined a different proportion should be used. Solar projects require a different HL component. Average estimated generation for solar has been calculated to be 84 percent. Based on a review of 12x24 (months per year by hours per day) solar generation profiles, all solar generation falls within the hours of 6 a.m. and 10 p.m. On Sundays and Holidays, solar generation is considered Light Load (LL).

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, the CSPP/PURPA Forecast Sub-Team identified no concerns with the various forecasts input to the 2019 IRP.

3.6.2. Transferring Inputs into AURORA

To ensure that the CSPP and PURPA data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the CSPP and PURPA data within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the CSPP and PURPA forecast data prepared for the 2019 IRP reconciled to the inputs within AURORA. No further action was deemed necessary.

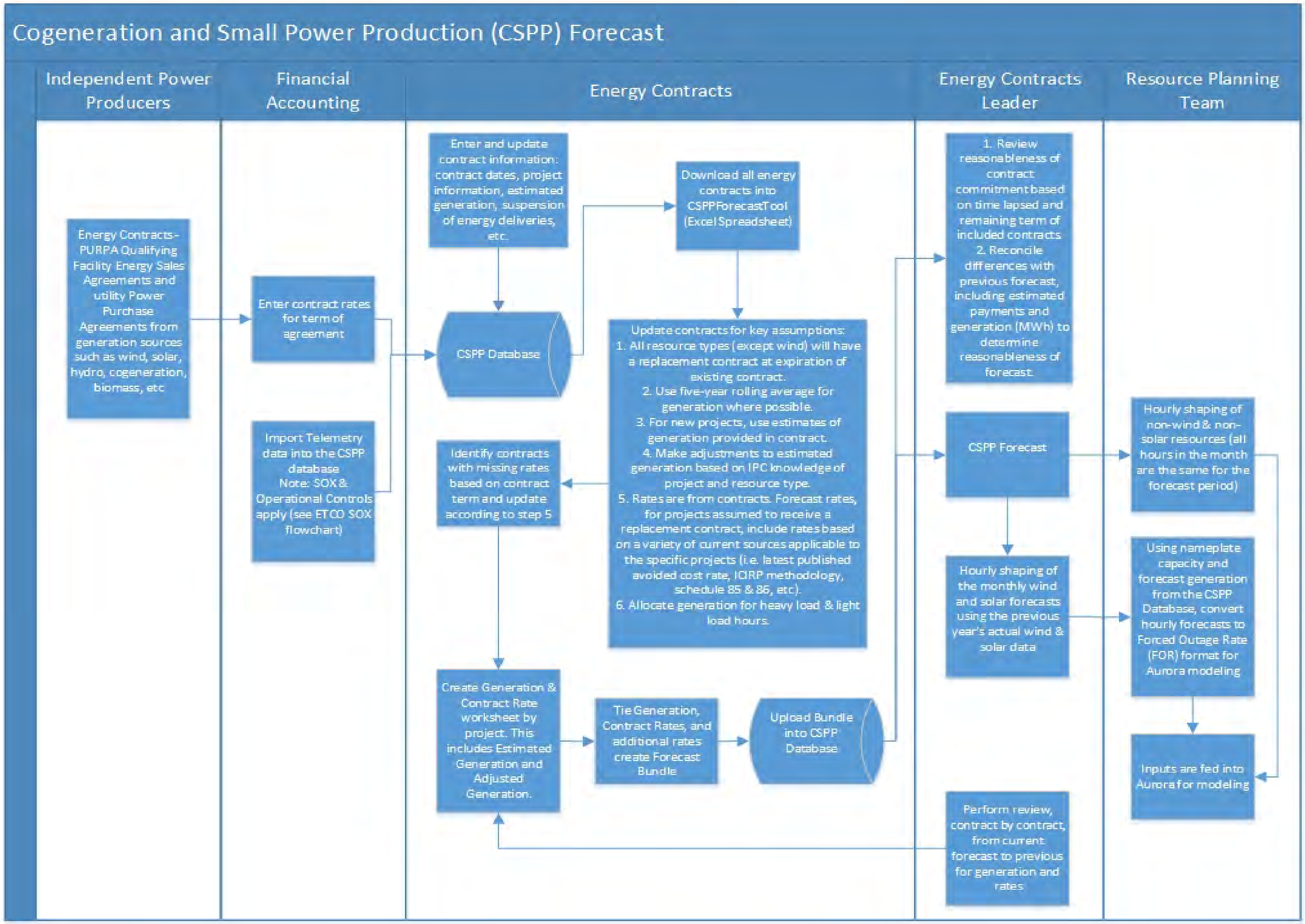

Figure 3.6 CSPP and PURPA Inputs Process Map

3.7 Demand Response and Energy Efficiency

3.7.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, the Demand Response (DR) and Energy Efficiency (EE) Sub-Team assessed forecast inputs related to Idaho Power's DR and EE programs. The following summarizes the inputs and key assumptions:

Demand Response

1. Capacity for the company's three DR programs (Residential A/C Cool Credit Program, Irrigation Peak Rewards Program, and Commercial/Industrial Flex Peak Program) is estimated using the prior year's maximum calculated capacity and customer dispatch shape from the previous summer (detailed in the DSM report, which is reviewed internally and filed with both commissions each March).

2. A DR event on the peak day in June, July, and August are incorporated into the hourly load forecast for each year during the 20-year planning period. Hourly shaping factors are then applied over a target range of three hours prior to the peak hour and three hours subsequent to the peak hour for each event (the hourly shaping factors are consistently applied to all DR events over the 20-year period). The hourly shaping is then fed into AURORA. The sub-team discussed how the Resource Planning team reviews a graphical representation of a peak day (including a DR event with hourly shaping applied) and concluded that the hourly shaping of DR is reasonable.

Energy Efficiency

Company data (including sales and peak data, customer usage data, residential survey data, sales and load forecast data, program participation data, and avoided cost data) is provided to a third party—currently, Applied Energy Group (AEG)—to perform a DSM Potential Study biennially. Idaho Power then assumes AEG's energy efficiency forecasts in the IRP.

1. <u>Energy Efficiency bundles:</u> Idaho Power contracts with a third party—currently AEG —on a biennial basis to perform a DSM Potential Study that evaluates the potential amount of achievable and economic energy efficiency. The DSM Potential Study considers market adoption, customer preferences for energy-efficient technologies, and expected program participation. In 2019, AEG provided bundles of technically achievable energy efficiency, bundled at varying costs, in addition to the legacy DSM Potential Study output. These data associated with the potential amounts came directly from AEG and were input into AURORA without issue.

2. <u>AEG bundles to load forecast</u>: AEG created a total of 11 energy efficiency bundles. In the load forecast used in the 2019 IRP, Idaho Power assumed a level of energy efficiency. The review sub-team found that the input table for energy efficiency bundles showed the level of energy efficiency included in the load forecast compared to the level of energy efficiency contained in each of the 11 energy efficiency bundles provided by AEG. The levels in bundles 1 through 7 were included in the load forecast, leaving bundles 8 through 11 as inputs into AURORA. The review team

confirmed the assignment of the bundles, both in the load forecast and as inputs to AURORA, was appropriate.

3. Cost Savings: AEG provided the cost savings related to each energy efficiency bundle, with the costs for each of the bundles over the 20-year planning period using a 2.1 percent assumed escalation factor. These data came directly from AEG. The team noted, however, that AEG's applied 2.1 percent assumed escalation factor was inconsistent with the 2.2 percent assumed escalation factor used for other inputs within the IRP process. The team resolved that the 2.1 percent factor was reasonable as it was the latest factor when it was provided to AEG. Preparation of the 2019 IRP had not begun yet—and it was during the 2019 IRP preparation that a 2.2 percent factor was selected for other inputs. As a result, the team did not deem it necessary to perform a sensitivity analysis.

Sub-Team Results of Step I Review

Demand Response

Based on the above review of key assumptions and inputs, the Demand Response & Energy Efficiency Sub-Team identified no concerns with the Demand Response inputs to the 2019 IRP.

Energy Efficiency

Based on the above review of key assumptions and inputs, the Demand Response & Energy Efficiency Sub-Team identified no concerns with the Energy Efficiency inputs to the 2019 IRP.

3.7.2. Transferring Inputs into AURORA

To ensure the Demand Response and Energy Efficiency data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the Demand Response and Energy Efficiency inputs within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the Demand Response and Energy Efficiency data prepared for the 2019 IRP reconciled to the inputs within AURORA.

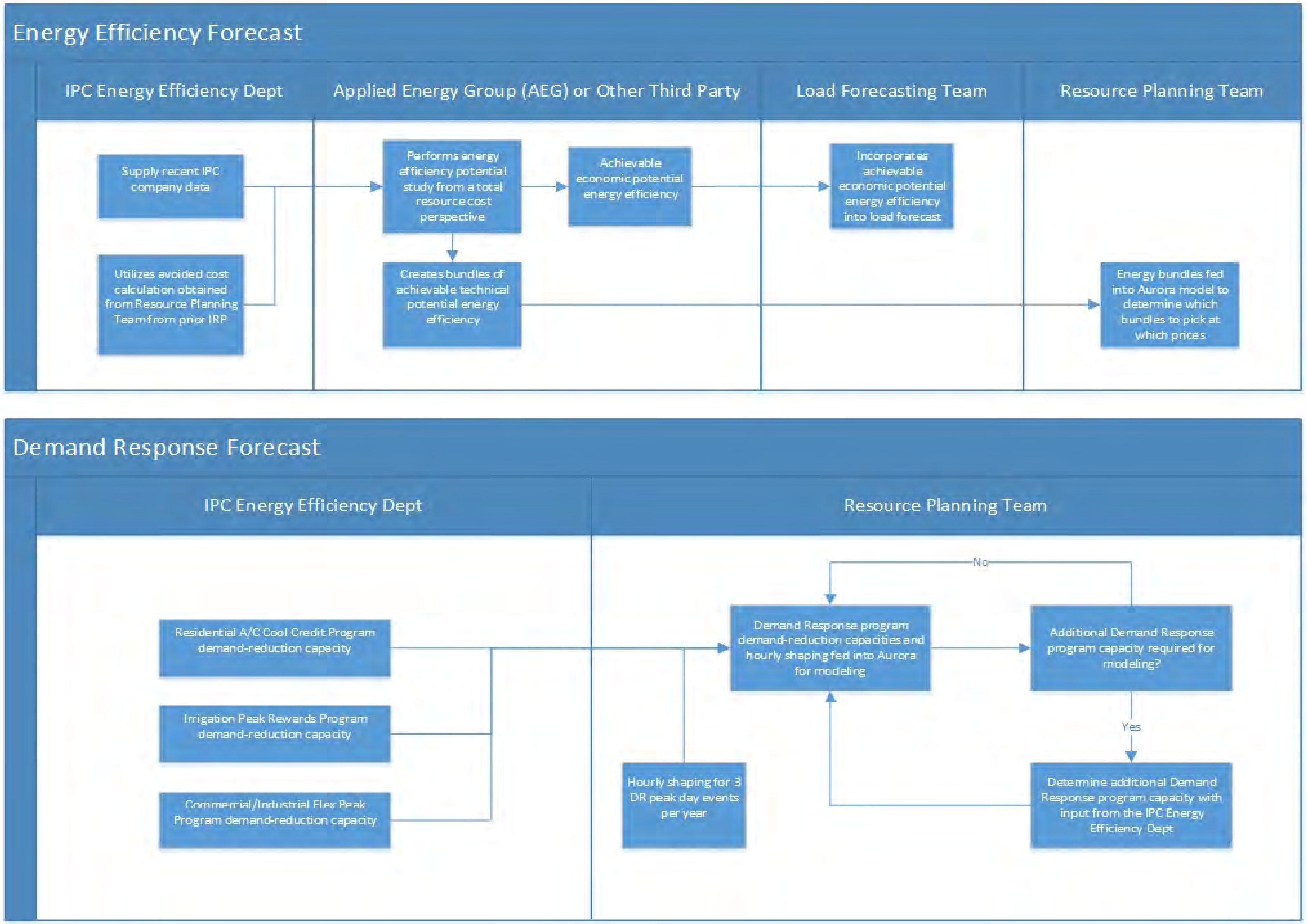

Figure 3.7 Demand Response and Energy Efficiency Process Map

3.8 Transmission Inputs Summary

3.8.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs related to the transmission system forecast. The transmission-related inputs included transfer capacity, including the impact of losses and wheeling rates. The following summarizes the key assumptions and inputs:

Transfer Capacity

1. Available transfer capacity (ATC) is determined by starting with the transmission lines' total transfer capacity and then removing the transmission that has been forecasted by month by other users such as Bonneville Power Administration. Also considered in ATC is the dispatch of external generation such as Valmy, Boardman, and Jim Bridger. The loss rate is the Joule effect, wherein energy losses occur as current and impedance generate heat in the conductors, which can impact on-line transmission capacity.

2. Wheeling rate by line is the cost due to the transmission owner for use of the transmission facility.

3. Available capacity for some lines is forecast by month due to the usage of the line and reflects the fluctuating generation of a resource attached to the line.

Transmission Operating Characteristics

1. The transmission system forecast prepared for the 2019 IRP includes transmission capacity, loss factors, and wheeling rates for each transmission line. For lines with capacities that vary with time, the transmission capacity was calculated by starting with the maximum total capacity and then subtracting a forecast of existing transmission commitments to arrive at the ATC.

Sub-Team Results of Step I Review

The sub-team reviewed the transmission system forecast prepared for the 2019 IRP, which resulted in adjustments to the loss rate, wheeling rate, and capacity for some of the transmission lines. Therefore, it was determined that sensitivity analyses should be conducted to determine the impact of the adjustments. The results of the sensitivity analyses are provided in Section 6.3.

3.8.2. Transferring Inputs into AURORA

To ensure that the transmission data prepared for the 2019 IRP was correctly input into the AURORA model, the sub-team exported a sample of transmission line data within the AURORA model and tied those inputs to the source file prepared by the responsible business unit.

It is important to understand that the IRP Planning Team individually models each transmission line with capacity in/out within AURORA. Due to the complexity, and that each individual line is a separate table in AURORA, the sub-team reviewed a sample of three transmission line inputs into AURORA: The ENPR line, Path 16, and B2H. During this review process, it was determined that the transmission system forecast data prepared for the 2019 IRP reconciled with the inputs into AURORA.

Sub-Team Results of Step II Review

The IRP Review Team found that the transmission capacity for the selected three lines was properly input into AURORA. The changes to the loss factor, wheeling rate, and capacity identified during the Step I Review were evaluated in a sensitivity analysis. The results of the sensitivity analysis are provided in Section 6.3.

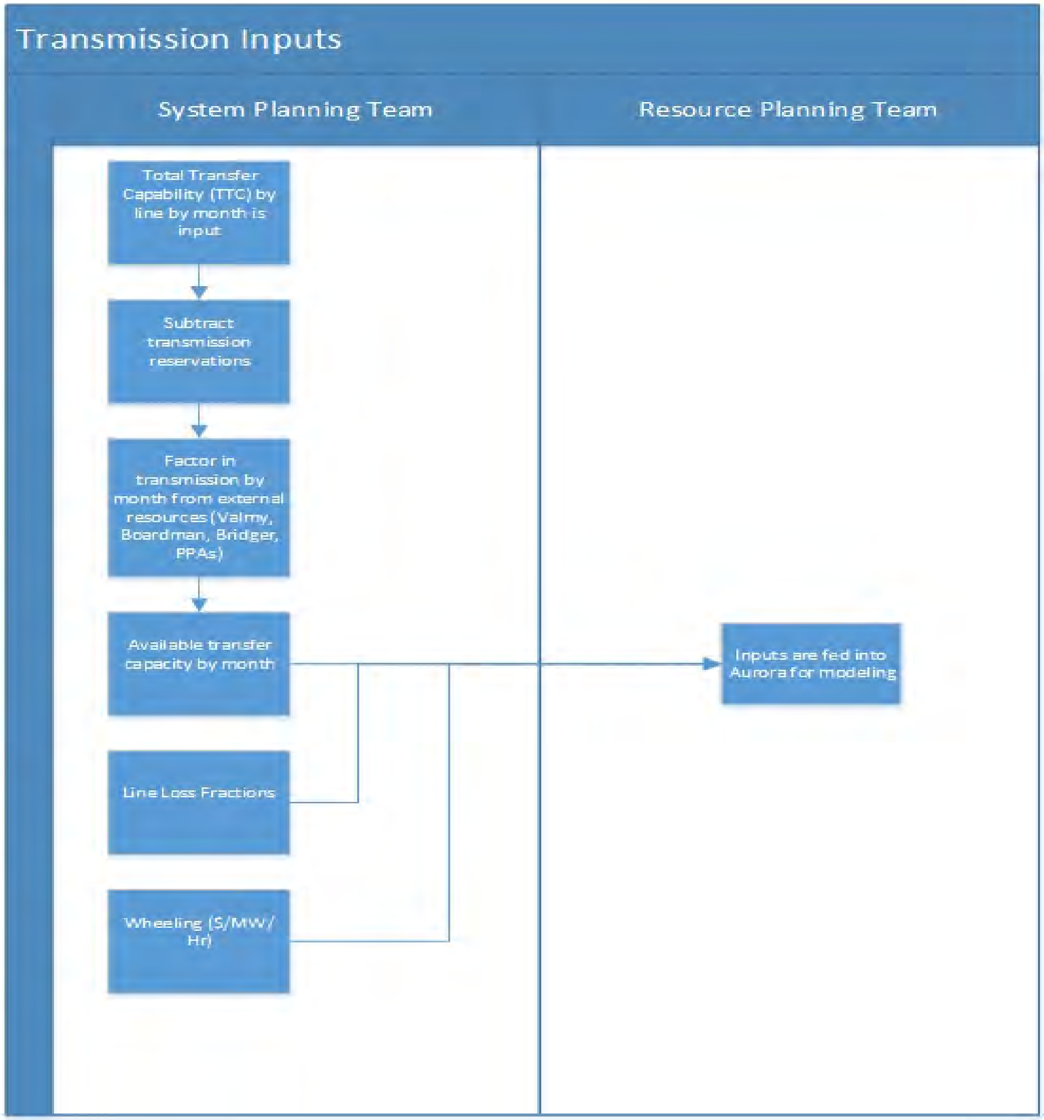

Figure 3.8 Transmission Inputs Process Map

3.9 Boardman to Hemingway Inputs Summary

3.9.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the financial assumptions related to the B2H transmission line. The general transmission system assumptions were evaluated in section 3.8 above. The following summarizes the key assumptions and inputs:

1. Because the same financial assumptions used for supply-side resources apply to the B2H transmission line costs, the pertinent discussion and review of those inputs are discussed in section 3.10 below.

2. Transmission revenue credits are included as a credit in the B2H cost calculations. They are estimated using Idaho Power's transmission rate forecast. The forecast includes the latest-year Federal Energy Regulatory Commission (FERC) Form 1 inputs to calculate the current Idaho Power transmission rate, and, for most components, creates an average inflation rate using the last three years of historical actuals to forecast the transmission rate into future years. If there is a known major change to any of the formula rate components (e.g., an asset swap), an adjustment would be made for that specific transaction. The B2H final build costs are added in year 2026, when the asset is expected to be in service in transmission plant. These costs are obtained from the Power Supply department. The resulting Idaho Power transmission rate forecast includes the change to transmission revenues expected with the addition of B2H.

Sub-Team Results of Step I Review

Notwithstanding the findings within the Financial Inputs Sub-Team (Section 3.10), the B2H Sub-Team found that the revenue credits were reasonable and properly included in the B2H PWorth model.

3.9.2. Transferring Inputs into AURORA

As discussed in Section 3.8.2, the B2H transmission capacity entered into AURORA was reviewed and reconciled with the transmission system data prepared for the 2019 IRP. The costs for B2H are not entered into AURORA but are manually added to the portfolio costs after the portfolio costs are exported from AURORA. The B2H costs are only added to the portfolios in which B2H is identified as a resource.

To test the addition of the B2H costs into portfolios, the planning gas and planning carbon scenario was selected for review. To add the B2H costs into the portfolio, the net present value (NPV) of the cost of the resource was determined. This was calculated by multiplying the levelized capacity cost (calculated in the PWorth model) by the capacity of the resource beginning in the year the resource is placed in service to determine the annual cost of the resource. The NPV of the B2H costs are calculated based on the annual costs of the resource for the 20-year IRP planning period. The sub-team reviewed the calculation and reconciled to the levelized capacity cost figure provided by Financial Accounting and verified that the proper discount rate of 7.12 percent was used. The total B2H cost (NPV) was then added to the total portfolio cost of each of the identified portfolios (NPV).

Sub-Team Results of Step II Review

The sub-team noted the B2H costs were properly added to the portfolio costs. However, differences were identified in levelized capacity cost (mills/kW/month) provided to the planning team due to different property tax and insurance rates. Therefore, a sensitivity analysis was conducted by updating these rates to obtain the new levelized capacity cost. Refer to Section 6.3 for results.

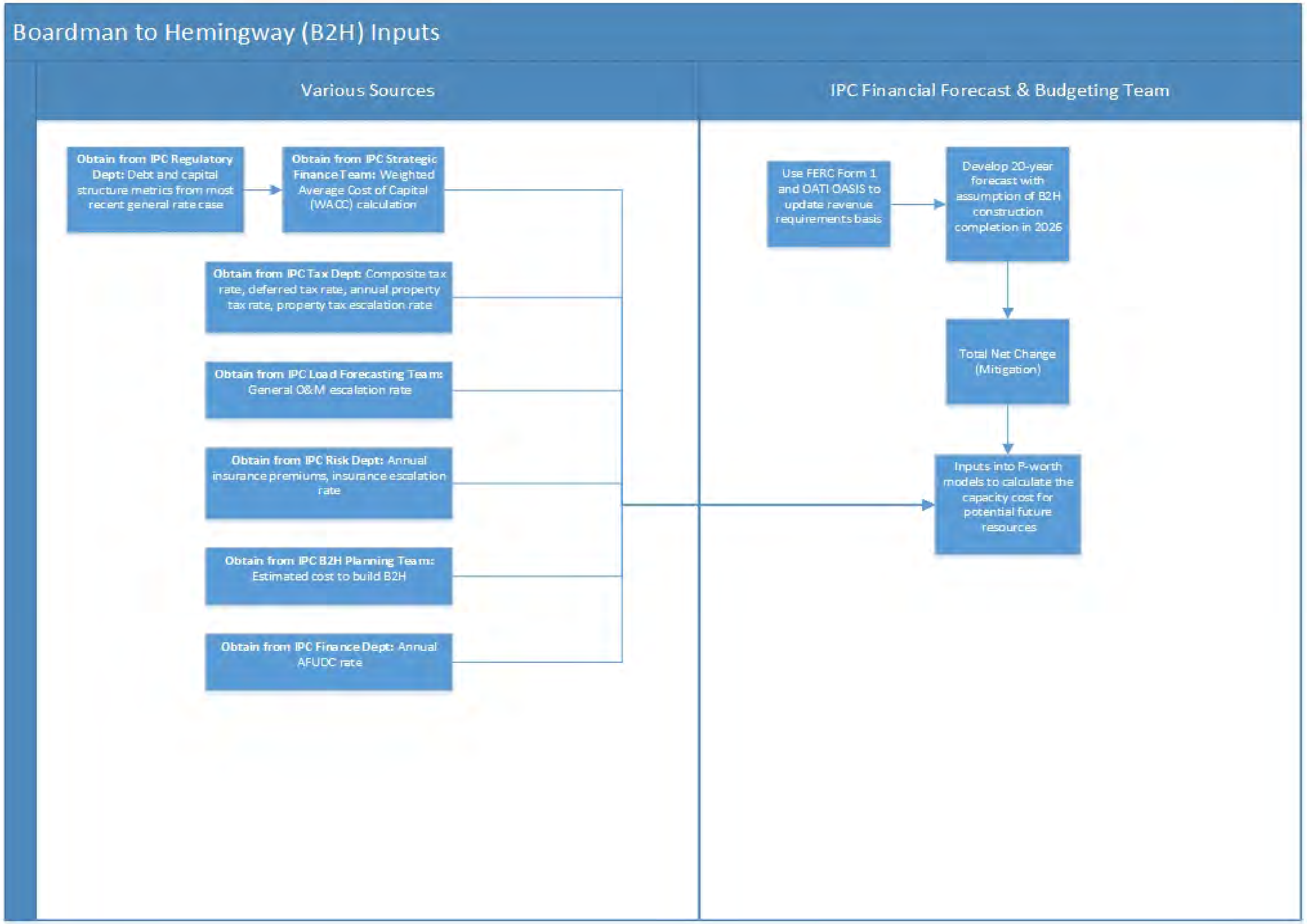

Figure 3.9 Boardman to Hemingway Inputs Process Map

3.10 Financial Inputs and Future Supply-Side Resources Summary

3.10.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team reviewed the financial inputs that were used to determine the costs for supply-side resources for accuracy. The following summarizes the key assumptions and inputs:

1. The discount rate (Weighted Average Cost of Capital) was determined to be 7.12 percent. This rate was determined by calculating the composition of debt, preferred stock, and common stock.

2. The corporate tax rate of 25.74 percent reflects the change in tax laws that occurred in 2018.

3. The deferred tax rate for Contributions in Aid of Construction (CIAC) and Construction Work in Progress (CWIP) was determined to be 21.30 percent.

4. The general O&M escalation rate is determined by the Load Forecasting department. This rate was analyzed using both US Bureau of Economic Analysis and Moody's Analytics Consumer Price Indices (CPI). The Moody's CPI future 20-year rate for 2018-2037 was used for the IRP general O&M escalation rate of 2.2 percent.

5. Property taxes are derived from the property tax escalation rate and the annual property tax rate as a percentage of investment. The applied rates to supply-side resources are the State of Idaho rate. This rate was determined to be appropriate because even though the exact location where assets might be built is unknown, the majority of Idaho Power's service territory is in Idaho (excluding B2H, which is addressed below).

6. Insurance costs are derived from an insurance escalation rate and annual insurance premiums as a percentage of investment. The applied rates to supply-side resources are based on the Insurance & Risk Management Advisor's knowledge of Idaho Power's current and past escalation rates and premiums.

7. The Allowance for Funds Used During Construction (AFUDC) rate is obtained from the Financial Reporting team. The rate used in the IRP is the current month AFUDC rate when the study was performed.

The financial assumptions are inputs used by multiple departments to forecast and model data throughout the IRP process. Therefore, the team ensured the rates were accurate and consistently applied throughout the review process.

The sub-team reviewed each of the financial assumptions with subject matter experts to verify the accuracy of the values used in the 2019 IRP. The values for most assumptions were validated and deemed reasonable. The following financial assumptions warranted additional review:

- Annual Property Tax Rates – Upon review of the property tax rates used to calculate the capacity costs of supply-side resources, the annual rate applied in the 2019 IRP was deemed stale. Through discussions it was determined this rate was rolled forward from the 2017 IRP and should be updated to 0.49 percent to reflect current Idaho property tax rates. The Idaho rate was used since the majority of the company's property is located in Idaho; an exception to this is B2H. Because the B2H line is primarily located in Oregon, the company determined that a blended property tax rate would better reflect the plant investment by jurisdiction. Based on this principle, property tax escalation rate applied to B2H should reflect Oregon trends as well.

- Annual Insurance Rates – Upon review of the annual insurance rate used, it was determined that a rate of 0.31 percent was being used, but the company's subject matter expert determined the rate should be 0.03 percent.

Sub-Team Results of Step I Review

The sub-team identified two areas that could have potential impacts on the IRP: Annual property tax rate (% of investment) and the annual insurance premium. A sensitivity analysis was performed for each, and the results are discussed in Section 6.3.

3.10.2. Transferring Inputs into AURORA

To ensure the data prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the financial inputs within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. The financial inputs within the AURORA model include the discount rate, inflation factor and levelized costs of future supply-side resources. During this review process, it was determined that the financial inputs prepared for the 2019 IRP reconciled to the inputs within AURORA.

Sub-Team Results of Step II Review

The sub-team noted the future supply-side resource costs were properly added to the portfolio costs. Changes to the levelized mills/kW/month costs were included in a sensitivity analysis by updating the property and insurance rates to obtain the new levelized capacity costs and the results are discussed in Section 6.3.

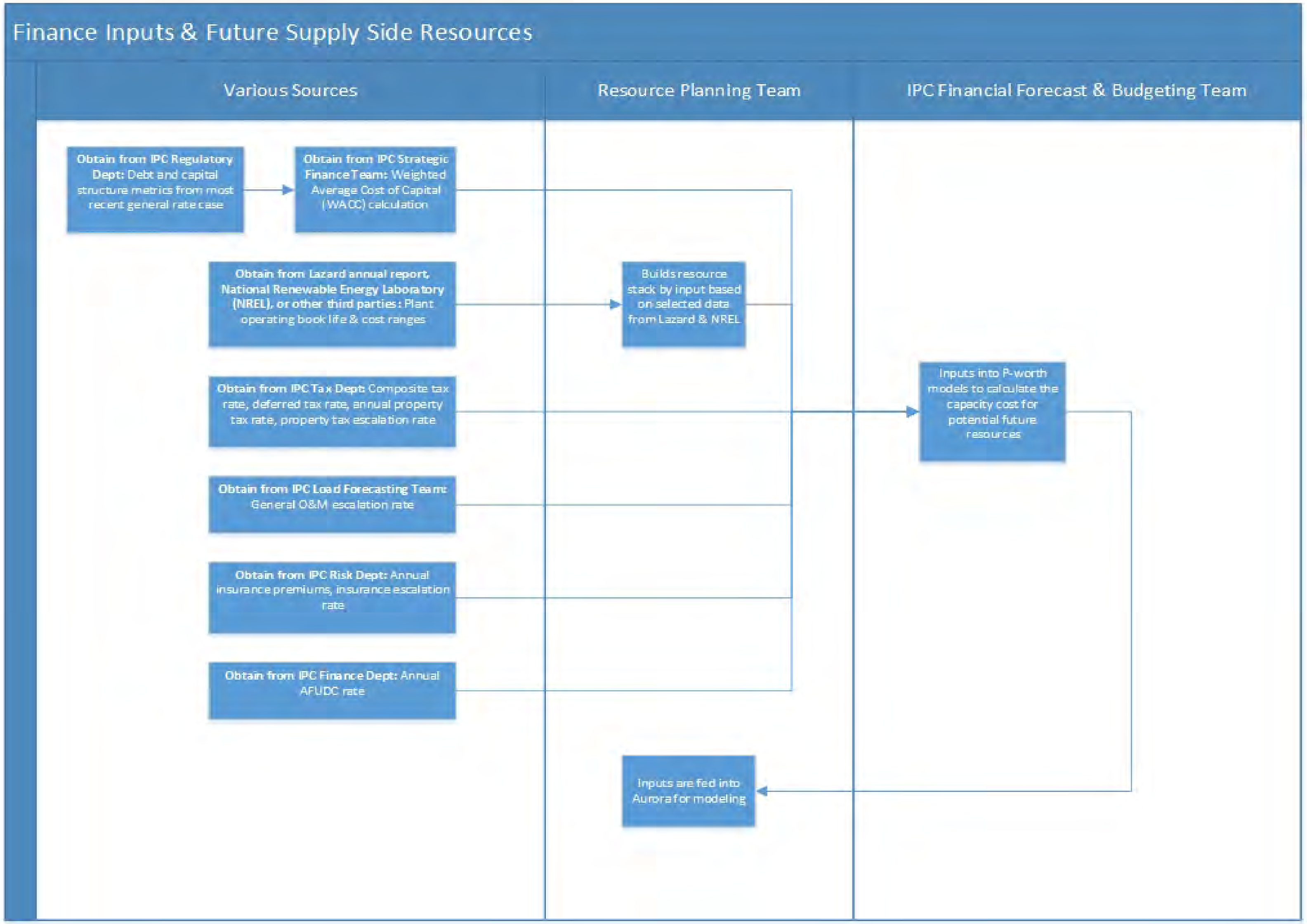

Figure 3.10 Financial Inputs/Future Supply Side Resources Process Map

3.11 Reliability Inputs Summary

3.11.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs related to system reliability. The reliability inputs included regulating reserve and reserve carrying capacity by resource. The following summarizes the key assumptions and inputs:

Seasons

1. Seasons were defined as follows:
    a. Winter = December, January, February
    b. Spring = March, April, May
    c. Summer = June, July, August
    d. Fall = September, October, November

Estimation of RegUp/RegDn for Wind:

2. The binning by Two Hours Ahead (2HA) forecast was defined as follows:
    a. Bin 1: 2HA wind forecast < 143 MW
    b. Bin 2:

Estimation of RegUp/RegDn for Solar:

5. Solar binning for winter was defined as follows:
    a. Bin 1: 0 MW-0.1 MW
    b. Bin 2: 0.1 MW-10 MW
    c. Bin 3: 10 MW-60 MW
    d. Bin 4: 60 MW-110 MW
    e. Bin 5: 110 MW and above
6. Solar binning for spring was defined as follows:
    a. Bin 1: 0 MW-0.1 MW
    b. Bin 2: 0.1 MW-10 MW
    c. Bin 3: 10 MW-135 MW
    d. Bin 4: 135 MW-220 MW
    e. Bin 5: 220 MW+
7. Solar binning for summer was defined as follows:
    a. Bin 1: 0 MW-0.1 MW
    b. Bin 2: 0.1 MW-10 MW
    c. Bin 3: 10 MW-185 MW
    d. Bin 4: 185 MW-245 MW
    e. Bin 5: 245 MW+
8. Solar binning for fall was defined as follows:
    a. Bin 1: 0 MW-0.1 MW
    b. Bin 2: 0.1 MW-10 MW
    c. Bin 3: 10 MW-115 MW
    d. Bin 4: 115 MW-180 MW
    e. Bin 5: 180 MW+

The company developed approximate regulation rules for use in the 2019 IRP based on historical Pi data (generation data obtained from SCADA) by season for the prior year. Regulation Up (RegUp) and Regulation Down (RegDn) percentages were assigned by hour/MW bin for load, wind, and solar. These percentages are ultimately entered into AURORA. During the review, the sub-team noted the calculation for RegDn percentages referenced the RegUp allocation factor instead of the RegDn allocation factor. The team determined a sensitivity analysis should be performed for impact evaluation.

To inform a comparative evaluation of the regulation rules developed for the 2019 IRP, Idaho Power reviewed the regulation percentages determined as part of the company's 2018 Variable Energy Resource Study (VER Study). Idaho Power's VER Study determined the impacts and costs associated with integrating variable energy resources, such as wind and solar, without compromising reliability. The study was developed in coordination with a group of Idaho Power subject matter experts and external experts (including members of the IPUC, OPUC, Idaho National Laboratory, Northwest Power and Conservation Council, Renewable Northwest, and the University of Idaho).

The integration costs in the VER Study provided a comparative evaluation of variable generation resources to other resource options. The tables within the VER Study provide percentages of seasonal RegUp (the generating capacity that can be ramped up intra-hour to respond to undersupply conditions) and RegDn (the generating capacity that can be similarly ramped down to respond to oversupply conditions) by "bin" for load, wind, and solar. The Reliability Sub-Team noted these percentages aligned with the percentages prepared for the 2019 IRP.

Another key reliability input reviewed by the sub-team was reserve carrying capacity by resource. This listing within AURORA is carried over from one IRP to the next given that a unit's ability to carry reserves does not change between IRP cycles. During the sub-team's review of this listing, it was noted that Valmy Units 1 and 2 were listed as having the ability to provide reserve carrying capacity; however, Idaho Power's Load Serving Operations (LSO) department noted these units do not currently provide any reserves. The Reliability Sub-Team determined a sensitivity analysis should be performed.

Sub-Team Results of Step I Review

The sub-team identified two items that could have impacted the IRP including the allocation factor used for the RegDn percentages and the reserve carrying capacity of Valmy Units 1 and 2. A sensitivity analysis relating to these items was performed. The results are discussed in Section 6.3.

3.11.2. Transferring Inputs into AURORA

To ensure the data prepared for the 2019 IRP was correctly entered into AURORA, the sub-team exported the reliability inputs within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the reliability inputs prepared for the 2019 IRP reconciled to the inputs within AURORA. As noted above, during the Step 1 review process the sub-team identified necessary corrections to the allocation factor used for the RegDn percentages, as well as the reserve carrying capacity of Valmy Units 1 and 2. These adjustments were entered in AURORA and sensitivity analysis was performed, as discussed further in Section 6.3.

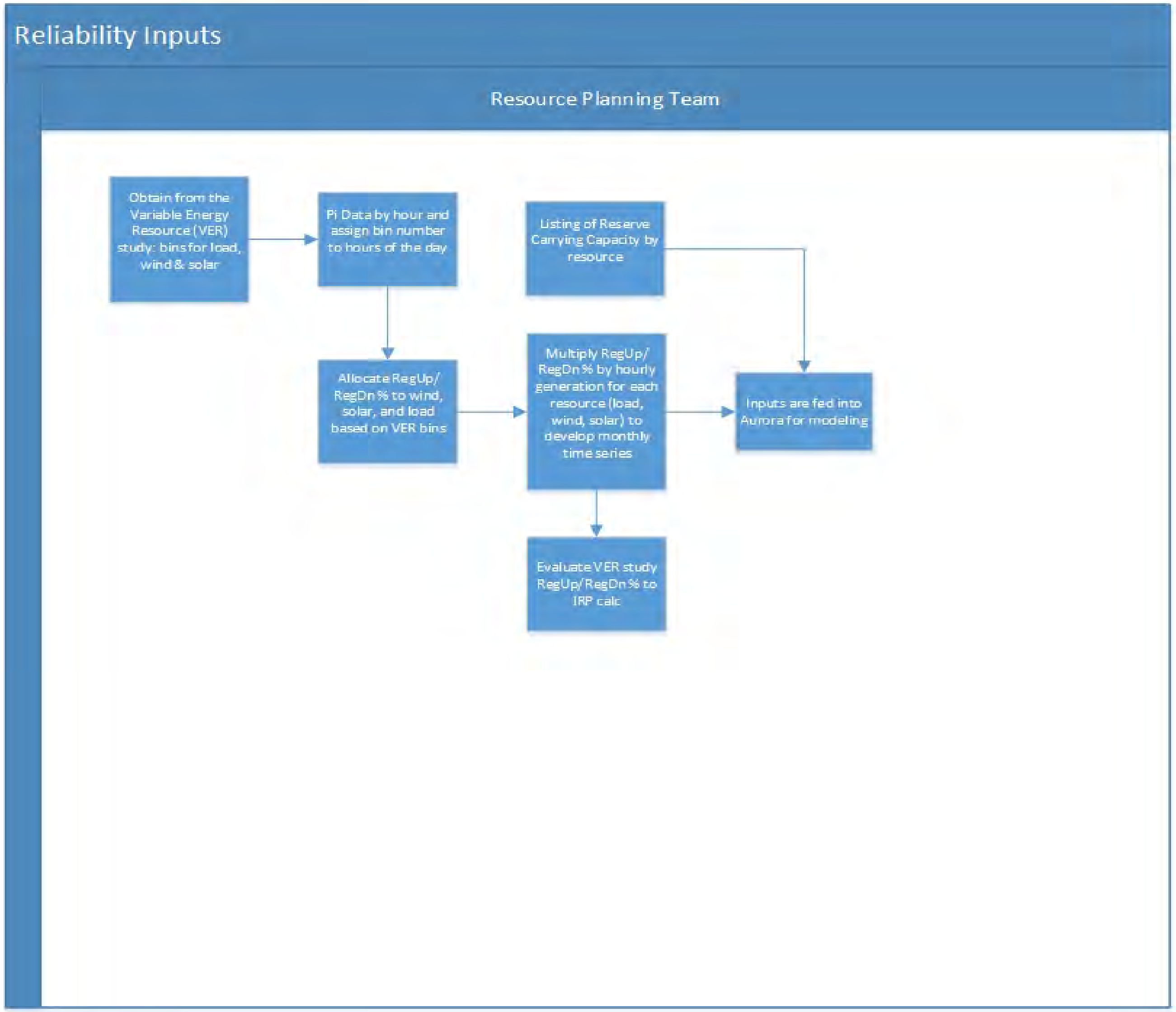

Figure 3.11 Reliability Inputs Process Map

4. AURORA System Settings

In Step III of the IRP review, the System Settings Sub-Team performed an assessment of the setup and utilization of the AURORA model for the 2019 IRP. Specifically, this sub-team was assembled to review the model settings that were applied to perform long-term capacity expansion and unit commitment optimization runs in support of the 2019 IRP filing.

4.1 System Settings Review Methodology

The System Settings Sub-Team systematically stepped through AURORA to review all known model system settings. There are three distinct locations within the AURORA model graphical user interface (GUI) where system settings can be adjusted: Project Setup Menu, Simulation Options Menu, and Input Tables. The sub-team created an itemized list of the system settings that reside in each location. The sub-team then reviewed each setting to ensure that they were correctly configured for the 2019 IRP. The discrete settings that were reviewed are shown in Table 4.1 below. It is important to note that not all settings identified in Table 4.1 were utilized in the 2019 IRP. The listed settings are solely a summary of the system settings that the sub-team reviewed for reasonableness in the 2019 IRP.

Table 4.1 AURORA System Settings

Project Setup Menu	Simulation Options Menu	Input Tables
• Active study type • Study period • Study cases and change sets utilized • Output database type and location	• Dispatch settings • Economic base year • Min gen backdown penalty • Resource dispatch margin • Calculate system-wide marginal resources • Inclusion of variable O&M in dispatch • Inclusion of emissions costs in dispatch • Treat ORM input as nominal • Use operating reserves • Use input prices • Use commitment feedback in LDC solve • Use demand net of must-run for hydro shaping • Ignore start costs in commitment • Treat emissions price input as nominal • Use capacity for MW-based commitment input • Use demand in all areas for hydro shaping • Use enhanced storage logic for all storage units • Use bidding logic • Threat resource bidding adder input as nominal • Outage method • Convergent cycle length • Freq duration outages base on elapsed time • Write frequency duration outage debug table • Combine resources segments in reporting • Report averages using online ours only • Include emissions in value reporting • Include fixed O&M in value reporting • Run general risk analysis • Do risk sampling only • Latin hypercube sampling • Number of iterations	• Zonal definition • Resources • Risk definition • Storage setup • Portfolio resource • Portfolio information • New resources • Maintenance schedule • Link • Hydro vectors • Hydro monthly • General information • Fuels • Demand monthly, demand hourly, and demand escalation • Zonal conditions • Areas • Ancillary services

4.2 System Settings Review Results

After reviewing all model settings used in the 2019 IRP, the System Settings Sub-Team concluded that the majority of the model settings used for the 2019 IRP reflected default settings from the vendor, Energy Exemplar. The sub-team determined the system settings and model setup utilized in the 2019 IRP were reasonable and did not recommend any changes. The sub-team concluded, however, that system settings should be reviewed in full prior to each IRP cycle to ensure consistency and accuracy in future modeling.

5. Model Verification and Validation of Key Inputs

In the final step of the review, the IRP Review Team sought to verify and validate the AURORA model outputs to ensure the model produced logical and consistent results. The sub-teams evaluated the reasonableness of the output or performed additional work to validate the data as necessary. For identified adjustments from Steps I through III, sensitivity runs were completed to determine the impact. These sensitivities compared the input data used in the *Amended 2019 IRP* and the associated results to reruns of the model with the adjustments identified by the IRP Review Team. The process to verify and validate the key inputs was unique to each topic and is described in each of the following sub-sections of the report.

5.1 Natural Gas Price Verification and Validation

To validate that the natural gas price forecasts were operating as expected in the model and the outputs were reasonable, the sub-team performed the following review:

Input Verification and Testing

As discussed in Section 3.1.2, the Natural Gas Price Forecast Sub-Team identified that variable transportation costs were not included in Idaho Power's specific natural gas price forecast. To determine the impact of including the natural gas variable transportation costs, a sensitivity analysis was run. The results of the sensitivity run showed an increase in portfolio costs ranging from 0.11 percent to 0.21 percent between the tested portfolios. This impact was deemed too small to impact ultimate resource selection within AURORA. However, the natural gas price forecast used in the *Second Amended 2019 IRP* is inclusive of transportation costs.

Model Validation

1. Peak-Day Comparison – The resource stack dispatched to meet demand through a peak day in the model was compared to the resource stack used to meet peak demand in the summer of 2017. This is a visual comparison to ensure resources are dispatching in the model in a reasonable manner. Natural gas provided a similar proportion of the resource stack in the model during peak hours. However, natural gas peaker plants (SCCTs) are dispatched in the model for a longer duration than actual dispatch indicates. While some variations between the model and actual dispatch are reasonable, as market conditions are expected to vary between the modeled forecasts and historical values, the Review Team conducted a sensitivity to explore this issue further. The sensitivity is described in Section 5.5 (Natural Gas Plant Step IV validation and verification).

2. Dispatch Model Sensitivity – The various natural gas price forecasts (high, mid, low) were compared against each other to determine if AURORA was adopting resources as expected. As a baseline, the review team examined levels of natural gas in a planning gas case. In comparison, the high-cost natural gas case replaces approximately 20 percent of the natural gas dispatched in the planning natural gas case with a combination of market purchases and coal. This result is as expected and showed that the model was dispatching gas resources appropriately based on underlying input costs.

3. Long-Term Capacity Expansion (LTCE) Results – The resources selected to add or reduce capacity in each portfolio by the LTCE model can be compared across natural gas forecast assumptions to determine if the results match expectations. This information is contained in the *Amended 2019 IRP* as Figure 8.3 for non-B2H portfolios and Figure 8.4 for B2H portfolios. In these figures, the first four (left-most) resource stacks shown were developed under a planning natural gas scenario. The next four were developed with the mid-natural gas forecast. And the last four (right-most) resource stacks were developed under a high-cost natural gas forecast. In both figures, equal or fewer natural gas resources were selected by the model in the planning gas scenarios than the resource stacks built under high-gas conditions when comparing the same carbon conditions. The reduction in natural gas selection is most obvious when comparing planning gas and generational/high carbon cases to the high gas and generational/high carbon cases. As expected, natural gas is selected considerably less under high gas price and generational and high carbon cost conditions.

Natural Gas Price Forecast Sub-Team Results of Step IV Review

An evaluation of the three checks performed on the natural gas pricing forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The natural gas price forecasts.
- The treatment of the natural gas price forecasts within the AURORA model.
- The outputs of the model.

5.2 Hydrology and Stream Flow Forecast Verification and Validation

To validate the hydrology and stream flow forecast was operating as expected in the model and the related constraints in AURORA were reasonable, the sub-team selected the most significant set of hydroelectric plants, the Hells Canyon Complex (HCC), and performed the following review:

1. HCC Hourly Ramp Rate – The AURORA modeling results for the 2019 year and base case run were aggregated into a single HCC resource (Hells Canyon + Oxbow + Brownlee). The hourly ramp rate for the HCC was plotted in a histogram. Based on historical observed ramp rates from 2004-2019, the HCC hourly ramp rate falls within 150 MW/hour up and down approximately 95 percent of the time. In AURORA, ramping of the HCC fell within 150 MW/hour approximately 80 percent of the time. While the model results did not exactly match the historical distribution, the general shape of the distribution is similar, and some deviation is expected in a model versus actual operations comparison. The sub-team also gained confidence observing the overall monthly energy budget is honored in the model. Accordingly, the team determined the hourly ramp rate results in the model output were reasonable.

2. HCC Pmax/Pave and Pmin/Pave ratios – Using AURORA modeling results for HCC, the ratio of the hourly daily maximum HCC generation (Pmax) was normalized by

the daily average generation (Pave). The same calculation was performed for the minimum generation (Pmin) normalized by Pave. The distribution of Pmax/Pave and Pmin/Pave were compared to the observed distribution of these ratios for the 2004-2019 historical period. This check was performed to gain an understanding of how much the AURORA model ramps the HCC up and down, compared to how much the company ramps the HCC in observed operations. The results generally showed that AURORA ramps the HCC over a wider range than in actual practice, with larger Pmax/Pave ratios generally occurring in all months except April. While not as pronounced, Pmin/Pave ratios generally were lower than the observed period, with April again being more constrained in AURORA than the historical data shows. Similar to the complex ramp rates, the sub-team concluded that it is more important that the model honor the monthly energy budget than exactly replicate ratios of Pmax/Pave and Pmin/Pave. Accordingly, the team determined the Pmax/Pave and Pmin/Pave ratio results in the model output were reasonable.

3. <u>Hells Canyon Dam Ramp Rate</u> – The AURORA modeling results for Hells Canyon Dam were evaluated to determine if the hourly ramp rate was comparable to how Hells Canyon Dam is operated in practice. Typically speaking, an hourly step of approximately 30 to 50 MW/hour corresponds to the maximum ramping capability at Hells Canyon Dam to meet the license requirement of changing river stage on the Snake River at Johnson Bar no more than 1 foot/hour. The AURORA results showed that Hells Canyon Dam is commonly ramped more than 50 MW/hour, which would likely lead to a compliance event if done in practice. Even though Hells Canyon is ramped more than 50 MW/hour, the results from the HCC as a whole (validation Steps I and II above) demonstrated that the energy produced for the HCC as a whole was reasonable. While a revision was not recommended for the 2019 IRP, the sub-team agreed that the issue warrants further consideration in future IRPs. Accordingly, the team discussed and determined the AURORA modeling results were reasonable.

4. <u>Hells Canyon Dam Daily Flow Fluctuation</u> – The AURORA modeling results for Hells Canyon Dam were evaluated to determine if the daily flow fluctuation was comparable to the way in which Hells Canyon Dam is operated in practice. While not currently a license requirement, but rather an anticipated license requirement, the company attempts to limit daily flow fluctuations below Hells Canyon Dam to 10,000 cubic feet per second (cfs) from June 1 through September 30. From October 1 through May 31, with the exception of the fall Chinook flat flow period, the company tries to limit daily flow fluctuations to 16,000 cfs below Hells Canyon Dam. The flow fluctuations were converted to a range in MW, using the Hells Canyon Dam k-factor. A fluctuation of 10,000 cfs corresponds to a daily MW fluctuation of 150 MW, and a fluctuation of 16,000 cfs corresponds to a daily MW fluctuation of 240 MW. The AURORA modeling results showed that these limits are generally honored October through April. May through September saw larger fluctuations than would likely occur based on the flow range guidance. As limits are generally honored and the flow fluctuations were as expected, the sub-team determined the results were reasonable.

5. <u>Hydroelectric Operation</u> – As an additional validation step, the sub-team validated hydroelectric operation in aggregate within the model. The team reviewed a graphical

representation of July 2019 forecasted peak day generation as modeled in AURORA to July 2017 actual peak day generation, noting forecast hydro generation for the peak day in AURORA behaved in a similar way to hydro generation on the historical peak day. The hydro generation is forecast lower in the morning hours and ramps up later in the day, as expected. The amount of hydro generation modeled during the peak hours closely matches the actual hydro generation during peak hours in 2017. The similarities between modeled results and actual historical data indicate that hydro generation is being modeled reasonably within AURORA.

Hydrology and Stream Flow Forecast Sub-Team Results of Step IV Review

An evaluation of the checks performed on the Hydrology, Stream Flow forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The Hydrology and Stream Flow forecasts.
- The treatment of the Hydrology and Stream Flow forecasts within the AURORA model.
- The outputs of the model.

5.3 Load Forecast Verification and Validation

To verify and validate the load forecast was operating as expected in the model, the sub-team anticipated a direct relationship between the load forecast input, as reviewed in Section 3.3.1 (Review Step I), and the output of the AURORA model. In Section 3.3.2 (Review Step II). The sub-team verified the hourly load forecast provided by the Load Forecasting team matched the load forecast included in all portfolios.

Load Forecast Sub-Team Results of Step IV Review

An evaluation of the checks performed on the hourly load forecast and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The hourly load forecast.
- The treatment of the hourly load forecast within the AURORA model.
- The outputs of the model.

5.4 Coal Plant Verification and Validation

To validate the operating characteristics, cost inputs, and coal price forecasts were operating as expected in the AURORA model and the outputs were reasonable, the following steps were performed:

Model Validation

1. Bridger Unit Generation – The Bridger unit generation in each year for Portfolios P2(3), P14(3), and P16(4) was compared to the minimum generation capabilities and maximum

generation capabilities per generator ratings in AURORA.[2] The annual modeled generation was determined reasonable if it fell between the minimum and maximum capability levels in a given year. Based on review of all three portfolios, all modeled generation outputs fell within these limits and the annual Bridger generation level was determined to be reasonable.

2. Bridger Fuel Expense – The Bridger unit fuel expense for each year for Portfolios P2(3), P14(3), and P16(4) was compared to the manual calculation of fuel expense based on fuel forecast inputs and the average heat rate of the plant. Reviewing over the 20-year period, if the annual Bridger unit fuel expense for a year was higher than the fuel expense calculated using the average plant heat rate more than 50 percent of the time, then the fuel expense is deemed intuitively reasonable. This threshold is based on the theory that the Bridger plant would be running at minimums during certain times, resulting in a lower efficiency, which, in turn, increases the fuel expense per MWh. Review of all three portfolios showed that modeled fuel expense fell within these limits and the annual Bridger fuel expense was deemed intuitively reasonable.

3. Bridger Fixed Cost Expense – The AURORA Bridger unit fixed cost for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of fixed expense based on fixed cost per MW-week inputs and rated capacities. AURORA's fixed costs and common facility costs in the portfolios should reconcile to the manual calculation of fixed costs. Review of all three portfolios showed that modeled fixed costs reconcile to the fixed cost inputs.

4. Bridger Variable O&M – The Bridger variable O&M expenses for each year in P2(3), P14(3), and P16(4) were compared to a manual calculation of variable O&M expense based on the updated O&M per MWh rates provided by Finance.

5. Valmy Fuel Expense – The Valmy unit fuel expense entered into AURORA for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of fuel expense based on fuel forecast inputs and the average unit heat rate. If the annual Valmy Unit 2 fuel expense in the model is higher than the fuel expense calculated using the average plant heat rate more than 50 percent of the time, then the fuel expense is deemed intuitively reasonable. This is based on the theory that if the Valmy plant is running at minimums at times, the result is a lower efficiency, which, in turn, increases the fuel expense per MWh. Review of all three portfolios found all modeled fuel expenses met this constraint.

6. Valmy Variable O&M – The AURORA Valmy variable O&M for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of variable O&M expense based on actual O&M per MWh rates.

[2] Section 6.2 provides a detailed discussion of why these portfolios were selected as the basis for additional analysis.

Coal Units Sub-Team Results of Step IV Review

The sub-team determined that coal unit operations were modeled as expected in AURORA. Updates were made to the Bridger fixed, Bridger common facility costs, and variable O&M costs, and, through validation, were included in the portfolio cost re-runs as expected.

5.5 Natural Gas Plant Verification and Validation

To validate the operating characteristics of the natural gas plants were functioning as expected in the model and to address the inconsistencies identified in Sections 3.5.1 and 3.5.2 (Review Steps I and II) related to start-up costs and the ramp rate for Langley Gulch, the following steps were performed:

Input and Setting Verification

1. Variable O&M Rate for Langley – It was noted during the Step IV review of the coal inputs that AURORA interprets the variable O&M input rate as a nominal 2012 amount and then escalates the rate to a 2019 nominal amount. This was also determined to be the case for the variable O&M input rate for Langley Gulch. The sub-team determined the variable O&M rate had already been input in AURORA at a 2019 nominal rate of $2.67 and would need to be deflated to account for the automatic escalation performed in AURORA. The 2019 nominal rate of $2.67 was deflated to a 2012 nominal rate of $2.37. This correction did not affect the natural gas peaking plant units, as the variable O&M expense had been incorporated into the start-up costs.

2. Review Gas plant settings in AURORA – The gas plant settings were reviewed for reasonableness by the company's subject matter experts. The following settings were discussed and deemed reasonable: Heat rate, capacity, forced outage rate, heat rate at minimum, minimum capacity, min up time, and min down time. The sub-team identified two model settings that were not used: 1) Fixed O&M and 2) Non-Cycling. Fixed O&M was not used in the model because the costs are the same among all alternatives and are therefore unnecessary. The Non-Cycling setting was not used as it is not a plant characteristic, but rather a 5 percent premium applied to the dispatch price to ensure that the unit is being dispatched at a profit.

Model Validation

1. Peaking Plants– A sensitivity analysis was performed that changed the maintenance calculation of two peakers—Bennett Mountain and Danskin 1—from a variable O&M charge (which spreads maintenance costs across MWh) to a cost per start. The small peakers (Danskin 2 and 3) were also included in a separate start cost sensitivity analysis. The sensitivity analysis showed that the use of a variable O&M charge in the model resulted in understatement of the total maintenance costs, while the use of a cost per start captured the full cost of plant maintenance. Further, the use of a cost per start showed a decrease in the number of starts without a corresponding decrease in total energy. To further validate the results, the sub-team compared the results of the AURORA output to actual 2019 maintenance costs. The variance between the modeled maintenance costs and 2019 actuals was within 3 percent, a variance the sub-team considered reasonable. The

sensitivity analysis showed minimal change in total portfolio NPV cost compared to the amended 2019 IRP (ranging from an approximate 0.8 percent increase in NPV for P2(3) up to about a 1.2 percent increase for P16-4). For the Danskin 2 and 3 start-up cost sensitivity, an increased start-up cost for these two units did not materially change the portfolio NPV.

2. Ramp Rate for Langley – The ramp rate for Langley was set at 100 percent, meaning that the plant can ramp from 0 to full capacity in one hour. The actual ramp rate is less than 100 percent and varies based on starting conditions. This modeling assumption was discussed with the company's subject matter experts, and a sensitivity was performed in AURORA to assess the impact of different ramp rates on the total portfolio NPV costs. Compared to the *Amended 2019 IRP* modeling with a 100 percent ramp rate, the following reduced ramp rates were used to determine impact on portfolio cost in NPV: A 23 percent ramp rate increased the NPV by 0.05 percent; a 50 percent ramp rate increased the NPV by 0.02 percent; and a 60 percent ramp rate increased the NPV by 0.05 percent. The results show that reduced ramp rates have only a minimal increase to the portfolio NPV and have an immaterial impact on the overall portfolio outcomes. The sub-team determined that a 60 percent ramp rate would better reflect actual operations and the plant setting was adjusted accordingly.

3. Review of Key AURORA Output – Key AURORA outputs for Langley Gulch, listed below, were reviewed by the company's subject matter experts and deemed reasonable based on comparison to historic actuals:

    a. Average Annual MWh Output
    b. Average Minimum Capacity MW
    c. Peak Capacity MW
    d. Total Annual MWh Output
    e. Annual Capacity Factor
    f. Total Hours Run
    g. Average Forced Outage MW

Natural Gas Plant Sub-Team Results of Step IV Review

The sub-team concluded that AURORA modeled natural gas plant operations as expected. The sub-team also reviewed the system settings related to natural gas plants and they were deemed reasonable. Adjustments were made to the peaker plants' start-up costs and variable O&M rates. Each adjustment was put through a sensitivity analysis, the results of which are discussed in Section 6.3. Additionally, these natural gas plant adjustments were evaluated in aggregate through portfolio analysis and the results are also discussed in Section 6.3.

5.6 CSPP and PURPA Verification and Validation

To verify and validate that the CSPP and PURPA forecast was operating as expected in the model, the sub-team assumed a direct relationship between the CSPP/PURPA generation forecast input (as reviewed in Section 3.6.1) and the output of the AURORA model. The sub-team verified that the CSPP/PURPA generation included in all portfolios, totaling 57,869,550.55 MWh over the 20-year planning period, matched the forecast inputs.

CSPP Sub-Team Results of Step IV Review

An evaluation of the checks performed on the CSPP/PURPA forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The CSPP/PURPA forecasts.
- Treatment of the CSPP/PURPA forecasts within the AURORA model.
- The outputs of the model.

5.7 Demand Response and Energy Efficiency Verification and Validation

To validate that Demand Response (DR) and Energy Efficiency (EE) were operating as expected in the model, the sub-team performed the following review for each:

Demand Response

Legacy and expanded DR programs were validated for capacity, shaping, and cost as outlined in Section 3.7.2 (Review Step II). Further validation was conducted to ensure that AURORA was treating DR consistent with the way Idaho Power's DR operates:

1. DR Adoption – The sub-team compared AURORA logic to expectations by evaluating a zero-carbon-cost portfolio to a high-carbon-cost portfolio. The team agreed that it would expect AURORA to elect for more DR in the high-carbon-cost portfolio. Evaluation of the test portfolios—Portfolio 1 (planning gas, no carbon) and Portfolio 12 (high gas, high carbon)—confirmed the team's hypothesis: Portfolio 1 (zero carbon cost) showed no DR expansion while in Portfolio 12 (high carbon cost) expanded Demand Response programs by 40 MW over the planning period.

2. DR Dispatch Function – While performing DR verification and validation, dispatch settings for DR were reviewed. It was identified that future DR was only dispatched in resource deficit situations. The team determined it would be more appropriate and consistent with DR program operations to set these programs to dispatch during summer peak load hours. Testing of this change showed greater amounts of dispatched DR under the peak load setting.

3. DR Cost of Capital – The sub-team reviewed the fixed costs associated with DR programs within the framework of future supply-side resources. This review revealed that the annualized cost of capital only applied to the three peak summer months (June, July, and Aug) when DR programs are dispatched. Upon discussion with subject matter

experts, the sub-team determined that the annualized cost of capital for those programs should be spread across the entire year. Sensitivity analysis revealed an impact of approximately $0.4 million per year for each 5 MW tranche of DR. As a result, the sub-team determined the cost of capital for DR should be spread throughout a 12-month period versus just summer peak months.

Energy Efficiency

To verify and validate that EE was operating as expected in the model, the sub-team confirmed that the levels of economic achievable EE included in the load forecast input matched the EE bundles identified by AEG, as reviewed in Section 3.7.1 (Review Step I) and the output of the AURORA model.

DR-EE Sub-Team Results of Step IV Review

An evaluation of the checks performed on DR and EE, as well as model outputs, resulted in the following conclusions:

- DR is being adopted as expected in AURORA.
- DR should be dispatched to offset peak load during peak summer months when DR programs are operating.
- The cost of capital for DR should be spread across the year rather than just in summer peak months.
- The inclusion of economic achievable potential EE is included in the hourly load forecast as expected.
- The treatment of the potential energy efficiency included in the hourly load forecast within the AURORA model was reasonable.

5.8 Transmission Verification and Validation

Because there is not an AURORA output produced as a result of the transmission assumptions, the verification and validation related to transmission focused on the sensitivity analysis recommended in Section 3.8.1 (Review Step I) and Section 3.8.2 (Review Step II), which resulted in adjustments to loss fractions, wheeling rates, and capacity as shown in Table 5.1.

Table 5.1 Updated Transmission Assumptions

Link	Losses fraction	Wheeling changes	Capacity (MW)
IPC B2H In	0.0445 to 0.019		
PAC B2H Import		$2.83 to $3.67	
IPC B2H export			+85
LGBP out	0.066 to 0.036		
LOLO in	0.0445 to 0.03		+53 BDMN retirement +200 (non-summer months) in 6/2026 BPA CF
LOLO out	0.0445 to 0.036		
JBWEST W-E IPC	0.0445 to 0.036		-350 (600 to 250)
BWEST E-W PAC		$3.67 to $3.58	
IPC-PAC (SMLK)		$3.58 to $3.67	
Path18 in	0.033 to 0.04	$3.67 to $4.72	
Path18 out IPC	0.0445 to 0.036		
Path18 out PACE	0.033 to 0.0445		

Transmission Sub-Team Results of Step IV Review

The inputs identified in Table 5.1 were updated in the model and the company re-ran four portfolios to validate the impact of the adjustments. The results of the new portfolios were compared to select portfolios in the *Amended 2019 IRP* and revealed that the largest difference was a 0.26 percent reduction in cost for the Preferred Portfolio. As a result of this minimal impact, the sub-team determined that the transmission assumption adjustments had a minimal impact on cost and were ultimately immaterial to portfolio selection.

5.9 Boardman to Hemingway Inputs Verification and Validation

To validate the B2H financial assumptions, the sub-team reviewed the addition of B2H costs to portfolios in which B2H was an identified resource. The costs for B2H were not entered into AURORA but were manually added to the portfolio costs for B2H-specific portfolios after the portfolio costs were exported out of AURORA. The sub-team validated that the costs were included as expected in Section 3.9.2 (Review Step II).

Boardman to Hemingway Inputs Sub-Team Results of Step IV Review

The sub-team identified the B2H net present value costs were appropriately added to the AURORA modeled costs, as expected. Updates were made to the B2H estimated levelized capacity cost.

5.10 Financial Inputs and Future Supply-Side Resource Verification and Validation

To verify and validate the financial assumptions used to calculate the levelized costs of supply-side resources and to address the inconsistencies identified in Section 3.10.1 and 3.10.2 (Review Steps I and II) related to property tax rates and annual insurance premiums, the sub-team performed the following steps:

1. Property Tax Rate – The team identified several financial inputs that were updated based on the information gathered in the review meetings as noted in Sections 3.10.1 and 3.10.2 (Review Steps I and II). The property tax rate was updated from 0.29 percent to 0.49 percent and annual insurance premiums were changed from 0.31 percent to 0.03 percent. The PWorth model was updated for each new supply-side resource to reflect the change in cost assumptions.

2. Secondary Review of Financial Assumption System Settings – The sub-team conducted a secondary check of financial assumptions in the LTCE model decision making and found them reasonable and consistent with the Step III review.

3. Future Supply-Side Resource Adoption – The sub-team compared AURORA logic to expectations by evaluating a zero-carbon-cost portfolio to a high-carbon-cost portfolio. The team agreed that it would expect AURORA to select coal exits earlier in the high-carbon-cost portfolio. Evaluation of the test portfolios—Portfolio 1 (planning gas, no carbon) and Portfolio 12 (high gas, high carbon)—confirmed the team's hypothesis: Portfolio 1 (zero carbon cost) removed 318 MW of coal while Portfolio 12 (high carbon cost) removed 849 MW of coal. This indicates that the logic within the AURORA LTCE performs according to expectations.

Financial Inputs and Future Supply-Side Resources Sub-Team Results of Step IV Review

An evaluation of the checks performed on the financial inputs and future supply-side resource outputs indicate the following were reasonable within the 2019 IRP analysis:

- Debt to Equity composition.
- Weighted Average Cost of Capital.
- General Escalation Factor (as measured by CPI).
- General Future Resource specifications as outlined (e.g., economic life, heat rate, overnight capital).

- Annual Escalation and de-escalation rates associated with future resources.

An evaluation of the checks performed on the financial inputs and future supply-side resource outputs indicate the following were subject to change within the 2019 IRP analysis:

- Property tax rate used in the PWorth model of future supply-side resources.
- Insurance premium rate used in the PWorth model of future supply-side resources.

5.11 Reliability Inputs Verification and Validation

To address the inconsistencies identified in Section 3.11.1 (Review Step I) related to RegDn percentages and the reserve carrying capacity of Valmy Units 1 and 2, and to validate that the other reliability inputs were operating as expected in the model, the following steps were performed:

Input Verification

1. LoadDown, SolarDown – To address the inconsistency identified in Section 3.11.1 (Review Step I) related to the RegDn percentages, the team determined a sensitivity analysis should be performed to understand the issue's impact. The team concluded the following:
    - The updates to LoadDown and SolarDown were immaterial to resource selection and portfolio cost.
    - The practical difference in the amount of reserve shortfalls between the *Amended 2019 IRP* and the updated LoadDown/SolarDown results is insignificant at 0.00001029 percent and 0.00010882 percent of total MWh over the 20-year planning horizon for RegDn and Spin, respectively.
    - Based on review of the sensitivity analysis, the team determined the reliability inputs included in the *Amended 2019 IRP* are reasonable.
2. Removal of Valmy's Ability to Provide Reserve Carrying Capacity – To address the inconsistency identified in Section 3.11.1 (Review Step I) related to the reserve carrying capacity of Valmy, the team determined a sensitivity analysis should be performed to assess the impact. Results of the analysis were as follows:
    - Prior to making the adjustment, Valmy Units 1 & 2 were providing almost no reserves (rounded to 0 percent of total reserves). Therefore, the removal of these units' ability to provide reserve carrying capacity did not make a material impact.
    - The practical difference in the amount of reserve shortfalls between the amount in the *Amended 2019 IRP* and the sensitivity analysis results is insignificant at 0.00085853 percent of total MWh over the 20-year planning horizon for RegUp reserve violations. The difference is even smaller for RegDn and Spin Reserve violations.

Model Validation

1. Contingency Reserves – These reserves are set at 6 percent (3 percent of load + 3 percent of generation) in the model. Historical data for 2019 showed 6 percent on average held as contingency reserves across the year. The AURORA output for 2019 also showed 6 percent contingency reserves on average for the year. As a result, the review sub-team determined that the reserves used in the model are reasonable compared to the historical reserves.

2. AURORA Max Reserves by Unit – Idaho Power's Load Serving Operations provided the max reserve capacity that each unit could potentially provide to the system. This was then compared to the max amount of reserves provided by each unit in AURORA for 2019. While on an hourly basis AURORA produced max reserves for some units above their stated max reserve capacity, the parameters defined within the model to characterize each unit's ability to provide reserve capacity up to a max were examined and found reasonable.

3. Reserve Shortfall – This check provided an assessment of how AURORA met reserves given a specific portfolio buildout. In reviewing the AURORA output for P16(4), in the 7-year action window, there was a projected reserve shortfall of just 54 MWh out of 119,000,000 MWh of total load. This assessment showed that AURORA is adequately meeting reserve requirements.

4. Loss of Load – During the 2019 IRP, there was an analysis performed on Loss of Load Probability for the four portfolios selected for manual optimization (2, 4, 14, and 16) to ensure that AURORA was providing adequate system reliability. The analysis found that each of the four portfolios provided adequate system reliability (LOLE <=.01 hours/year), which is well within the threshold commonly used in the industry of one day every ten years.

Reliability Inputs Sub-Team Results of Step IV Review

An evaluation of the checks performed on the reliability inputs and AURORA model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The reliability inputs.
- The treatment of the reliability inputs within the AURORA model.
- The outputs of the AURORA model.

6. IRP Review Results

6.1 Review Results Summary

The company conducted a comprehensive review process to deconstruct and examine all aspects of the 2019 IRP cycle from model inputs to model outputs, as discussed in prior sections of the report. While most inputs, system settings, and outputs were determined to be reasonable, the sub-teams collectively identified a few recommended adjustments. These adjustments are detailed above in Section 3 on inputs (review steps I and II), Section 4 on system settings (review step III), and Section 5 on model verification and validation (review step IV). The sections below provide a methodology by which the impact of adjustments can be understood, as well as a compiled list of all adjustments identified across the four steps of the review process and their relative impact on portfolio development.

6.2 Evaluation Methodology

To test the impact of identified input and system setting adjustments, a group of portfolios was selected for re-evaluation with refreshed information from this review process. The model was run for individual adjustments and then also with all adjustments collectively.

The adjustments were made to the following portfolios from the *Amended 2019 IRP*:

- Portfolio 16(4) – The Preferred Portfolio was included to determine the relative impact to the *Amended 2019 IRP* preferred plan.
- Portfolio 14(3) – Based on the number of identified coal input related changes, this portfolio was selected because it has later coal exits and a relatively low NPV compared to other portfolios with similar Bridger exit dates.
- Portfolio 2(3) – This was the best-performing portfolio without B2H in the *Amended 2019 IRP* and was selected to gauge the impact of the changes to the relative value of the project.

These portfolios were the most appropriate for impact testing because of their underlying characteristics and potential for change.

6.3 Impacts of Identified Adjustments

The results of the various sensitivity runs are shown in Table 6.1 and described below.

1. Natural Gas Transport Costs
    a. **Identified Changes –** The sub-team determined that the variable transport costs were inadvertently not included in the model.
    b. **Steps Taken –** These costs were added to the model.
    c. **Results –** The adjustment increased the cost of the Preferred Portfolio by 0.11 percent. This relatively minor impact varied between the tested portfolios with a ranged increase from 0.11 percent to 0.21 percent.
2. New Resource Financial Assumptions
    a. **Identified Changes –** The sub-team determined that the annual property tax rate and annual insurance premium needed adjustment. These values impact the cost of new resources added to Idaho Power's generation stack, including the B2H project.

b. **Steps Taken –** Financial assumptions were updated, and the financial analysis was performed again. The results of the financial analysis were then updated in the model.

c. **Results –** The financial adjustments decreased the cost of the Preferred Portfolio by 0.12 percent. This relatively minor impact was consistent among the tested portfolios with a ranged decrease from 0.04 percent to 0.12 percent.

3. Bridger Units 3 and 4 Fixed Cost Rates (Coal Reference)

    a. **Identified Changes –** The fixed cost rates for Bridger Unit 4 were inadvertently referencing the table of fixed costs for Bridger Unit 3 within AURORA.

    b. **Steps Taken –** The table reference within the model was corrected.

    c. **Results –** The Bridger coal unit reference adjustment increased the cost of the Preferred Portfolio by 0.04 percent. This relatively minor impact was consistent among the tested portfolios with a ranged increase in portfolio cost from 0.04 percent to 0.11 percent.

4. Regulation Reserves Adjustment

    a. **Identified Changes –** The solar and wind allocation factors for downward regulation referenced the upward allocation factors. Additionally, Valmy Unit 2 was modeled with the ability to provide regulation reserves, but the unit cannot provide regulation reserves.

    b. **Steps Taken –** The solar and wind references were redirected to the downward regulation allocation factors in the input spreadsheet and the regulation rules were updated in the model, while Valmy was adjusted within the model to not provide reserves.

    c. **Results** – The regulation reserve adjustments—including solar and wind changes, as well as Valmy—increased the cost of the Preferred Portfolio by 0.003 percent (rounded to 0.00 percent in Table 6.1). This relatively minor impact varied among the tested portfolios with a ranged increase between 0.003 percent and 0.10 percent.

5. Transmission Characteristics

    a. **Identified Changes –** The losses, wheeling rates, and capacities applied to some transmission lines required adjustment. Additionally, transmission capacity after the Boardman unit exit was understated.

    b. **Steps Taken –** The loss and wheeling rates were updated in the model. The transmission capacity adjustment was also implemented.

    c. **Results –** The losses, wheeling rates, and capacity adjustments decreased the cost of the Preferred Portfolio by 0.26 percent. This relatively minor impact varied among the tested portfolios from a decrease of 0.26 percent to an increase of 0.01 percent.

6. Bridger Variable O&M
    a. **Identified Changes –**The variable O&M costs associated with the Bridger units included the total variable O&M costs but should have been modeled as one-third of the costs, as contractually agreed to reflect the fractional ownership between Idaho Power and PacifiCorp.
    b. **Steps Taken –** The share of Bridger O&M costs was adjusted in the P-Worth model and the resulting adjustments were made to the AURORA model.
    c. **Results –** The Bridger variable O&M adjustment decreased the cost of the Preferred Portfolio by 0.42 percent. The impact among the tested portfolios ranged from a decrease of 0.42 percent to 0.48 percent.
7. Natural Gas Peaker Plant Startup Costs
    a. **Identified Changes –** The maintenance costs associated with natural gas peaker plants were captured only as a variable cost applied directly to the runtime of the unit. No startup costs were included, which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected.
    b. **Steps Taken –** The sub-team utilized historical and projected maintenance information for the peaker plants to determine an appropriate start-up cost. This cost was applied in the model. The gas dispatch from the model was then reviewed to confirm that the adjustment reduced the number of peaker plant starts and lengthened individual runtime durations as expected.
    c. **Results –** The adjustment to the startup costs of the peaker plants resulted in the largest impact to the results of all the adjustments across the tested portfolios. The Preferred Portfolio increased by 0.93 percent, with increases among the tested portfolios ranging from 0.79 percent to 1.07 percent.
8. Bridger Fixed Costs
    a. **Identified Changes –** While reviewing financial assumptions throughout the model, it was discovered that some of the financial assumptions for the Bridger coal units did not match the financial assumptions used throughout the rest of the model.
    b. **Steps Taken –** The financial assumptions were adjusted in the PWorth model and the resulting adjustments were made to the model.
    c. **Results –** The Bridger fixed cost adjustments increased the cost of the Preferred Portfolio by 0.14 percent. This relatively minor impact varied between the tested portfolios with a ranged increase from 0.14 percent to 0.26 percent.

9. Bridger Common Facility Costs

    a. **Identified Changes –** While reviewing financial assumptions throughout the model, it was discovered that some of the Bridger common facility costs were truncated as Bridger units were retired early.

    b. **Steps Taken –** The truncated Bridger common facility costs were added back to the Bridger fixed costs, which are added to the total portfolio costs for the collective review results for all cases.

    c. **Results –** The Bridger common facility cost adjustments increased the cost of the Preferred Portfolio by 0.51 percent. This impact varied between the tested portfolios with a ranged increase from 0.51 percent to 0.59 percent.

Assessed individually, the identified modeling adjustments showed limited impact to total portfolio costs. Collectively, the adjustments also had minimal impact on portfolio costs. Further, the collective adjustments did not change the ranking of the identified Preferred Portfolio against the best-performing non-B2H portfolio and the best-performing portfolio with later Bridger exit timing.

Table 6.1 Sensitivity Analysis Results

P16(4)	Amended 2019 IRP (Jan 2020)		Supplement Filing (May 2020)		Collective Review Results		% Difference			Aurora Sensitivities								
	P16(4) Base	Rank	P16(4) Base	Rank	All Cases	Rank	B/A	C/A	C/B	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 5,885,900		$ 5,885,900		$ 5,963,335					$ 5,897,604	$ 5,883,283	$ 5,893,225	$ 5,891,146	$ 5,877,895	$ 5,865,135	$ 5,947,855	$ 5,899,292	$ 5,963,335
Bridger Fixed			$ 130,565		$ 162,104					$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 162,104
B2H	$ 110,578		$ 110,578		$ 107,818					$ 110,578	$ 110,578	$ 110,578	$ 110,578	$ 107,818	$ 110,578	$ 110,578	$ 110,578	$ 107,818
Valmy					$ (5,035)					$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 5,996,478**	**1**	**$ 6,127,043**	**1**	**$ 6,228,222**	**1**	**2.18%**	**3.86%**	**1.65%**	**$ 6,133,712**	**$ 6,119,391**	**$ 6,129,333**	**$ 6,127,253**	**$ 6,111,243**	**$ 6,101,243**	**$ 6,183,963**	**$ 6,135,399**	**$ 6,228,222**
Difference										$ 6,670	$ (7,652)	$ 2,290	$ 211	$ (15,800)	$ (25,800)	$ 56,920	$ 8,357	$ 101,180
Percentage										0.11%	-0.12%	0.04%	0.00%	-0.26%	-0.42%	0.93%	0.14%	1.65%
P14(3)																		
($ x 1000)	P14(3) Base	Rank	P14(3) Base	Rank	All Cases	Rank	B/A	C/A	C/B	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 5,957,723		$ 5,957,723		$ 6,041,206					$ 5,971,719	$ 5,956,583	$ 5,965,994	$ 5,965,004	$ 5,952,606	$ 5,932,548	$ 6,024,703	$ 5,974,728	$ 6,041,206
Bridger Fixed			$ 64,162		$ 104,655					$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 104,655
B2H	$ 110,578		$ 110,578		$ 107,818					$ 110,578	$ 110,578	$ 110,578	$ 110,578	$ 107,818	$ 110,578	$ 110,578	$ 110,578	$ 107,818
Valmy					$ (5,035)					$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 6,068,301**	**2**	**$ 6,132,463**	**2**	**$ 6,248,644**	**2**	**1.06%**	**2.97%**	**1.89%**	**$ 6,145,116**	**$ 6,129,980**	**$ 6,139,392**	**$ 6,138,402**	**$ 6,123,244**	**$ 6,105,946**	**$ 6,198,101**	**$ 6,148,126**	**$ 6,248,644**
Difference										$ 12,654	$ (2,482)	$ 6,929	$ 5,939	$ (9,219)	$ (26,517)	$ 65,638	$ 15,663	$ 116,181
Percentage										0.21%	-0.04%	0.11%	0.10%	-0.15%	-0.43%	1.07%	0.26%	1.89%
P2(3)																		
($ x 1000)	P2(3) Base	Rank	P2(3) Base	Rank	All Cases	Rank	B/A	C/A	C/B	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 6,143,832		$ 6,143,832		$ 6,213,013					$ 6,156,103	$ 6,139,230	$ 6,151,462	$ 6,145,982	$ 6,146,004	$ 6,115,344	$ 6,193,934	$ 6,160,196	$ 6,213,013
Bridger Fixed			$ 64,162		$ 104,655					$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 104,655
B2H	$ -		$ -		$ -					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Valmy					$ (5,035)					$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 6,143,832**	**3**	**$ 6,207,994**	**3**	**$ 6,312,633**	**3**	**1.04%**	**2.75%**	**1.69%**	**$ 6,218,923**	**$ 6,202,050**	**$ 6,214,282**	**$ 6,208,802**	**$ 6,208,824**	**$ 6,178,164**	**$ 6,256,754**	**$ 6,223,016**	**$ 6,312,633**
Difference										$ 10,929	$ (5,944)	$ 6,288	$ 808	$ 830	$ (29,829)	$ 48,761	$ 15,022	$ 104,639
Percentage										0.18%	-0.10%	0.10%	0.01%	0.01%	-0.48%	0.79%	0.24%	1.69%

6.4 Decision Factor for Conclusion of the 2019 IRP

While the impact of adjustments detailed above are relatively limited, the number of identified adjustments shows this review process was a valuable exercise to help guide, shape, and inform the resolution of the 2019 IRP.

Following the conclusion of the review process, Idaho Power faced an important choice: To move forward with processing the *Amended 2019 IRP* and the associated Preferred Portfolio, knowing that the review showed minimal impact of the adjustments, or take the learnings from the review process and conduct a new analysis.

After considering these options and the immense importance of an accurate and trustworthy IRP, the company concluded that performing a new analysis for the 2019 IRP was the best and most logical path forward. The resulting and final IRP for this cycle, which incorporates all the adjustments identified in this review, is called the *Second Amended 2019 IRP*.

6.5 Recommendations for Future IRPs

The intended goal of this IRP review process was to identify adjustments and quantify their impact to conclude the 2019 IRP process. It became clear, however, that the learnings from this review could extend to future IRPs. To that end, the following improvements and insights were identified to ensure the IRP development process is more efficient, transparent, and accurate for future IRPs:

- **Future Reviews:** Elements of the review could be spun off to become valuable, routine features of IRP development. For example, an audit-style review of model inputs and input integration into AURORA could be an efficient way to ensure accuracy and reduce inadvertent errors in future IRP cycles.

- **Input Mapping:** The review of model inputs is made significantly easier by visual aids, such as flowcharts, that display the often-complex development of inputs into AURORA. Flowcharts are a valuable tool for streamlined IRP input validation and verification, but also for education and explanation with Idaho Power’s customers and stakeholders interested in resource planning practices.

- **Subject Matter Experts:** The role of subject matter experts will be expanded to include an early review of the model to assess the reasonableness of the inputs, system settings to actual practices, and model results.

- **Tool Evolution and Support:** Energy Exemplar, the developers of AURORA, regularly release updated versions of the software. One of the latest updates enables co-optimization of results, which would allow co-optimization of the portfolio specific to Idaho Power and the WECC. This development could greatly increase the efficiency of the IRP process. Because changes to AURORA by its developers should be fully understood by Idaho Power before commencing the next IRP, Energy Exemplar’s support services should be leveraged to the maximum extent.

7. CONCLUSION

The IRP Review Report is the culmination of six weeks of comprehensive study of Idaho Power's resource planning practices and modeling associated with the 2019 IRP cycle. The goal of the four-step review process was to deconstruct and examine the foundational elements of the 2019 IRP analysis—including model inputs and assumptions, model system settings, model verification and validation, and model outputs—and then identify actions to resolve the discovered issues.

In the course of the review, the company identified some appropriate adjustments to model inputs and treatment of data within the model. Assessed individually, the identified modeling adjustments showed limited impact to costs of select portfolios from the *Amended 2019 IRP*. Collectively, the adjustments also had a minimal impact on portfolio costs. Further, the collective adjustments did not change the ranking of the identified Preferred Portfolio against the best-performing non-B2H portfolio and the best-performing portfolio with later Bridger exit timing.

All identified issues are fully reflected in the company's final IRP for this cycle, the *Second Amended 2019 IRP*.

While undertaking this effort in the middle of an IRP under review was not ideal for everyone impacted by the resulting delay, Idaho Power is grateful for the opportunity to conduct such a thorough investigation of its approach and practices related to the IRP. The outcome of this review not only ensures the validity of the 2019 IRP, but also offers valuable lessons and insights that can be applied to future IRPs.