B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BP-20 Rate Proceeding

Final Proposal

# Power Market Price Study and Documentation

BP-20-FS-BPA-04

July 2019

# POWER MARKET PRICE STUDY AND DOCUMENTATION

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## COMMONLY USED ACRONYMS AND SHORT FORMS

| | |
|---|---|
| AAC | Anticipated Accumulation of Cash |
| ACNR | Accumulated Calibrated Net Revenue |
| ACS | Ancillary and Control Area Services |
| AF | Advance Funding |
| AFUDC | Allowance for Funds Used During Construction |
| aMW | average megawatt(s) |
| ANR | Accumulated Net Revenues |
| ASC | Average System Cost |
| BAA | Balancing Authority Area |
| BiOp | Biological Opinion |
| BPA | Bonneville Power Administration |
| Bps | basis points |
| Btu | British thermal unit |
| CIP | Capital Improvement Plan |
| CIR | Capital Investment Review |
| CDQ | Contract Demand Quantity |
| CGS | Columbia Generating Station |
| CHWM | Contract High Water Mark |
| CNR | Calibrated Net Revenue |
| COB | California-Oregon border |
| COE | U.S. Army Corps of Engineers |
| COI | California-Oregon Intertie |
| Commission | Federal Energy Regulatory Commission |
| Corps | U.S. Army Corps of Engineers |
| COSA | Cost of Service Analysis |
| COU | consumer-owned utility |
| Council | Northwest Power and Conservation Council |
| CP | Coincidental Peak |
| CRAC | Cost Recovery Adjustment Clause |
| CSP | Customer System Peak |
| CT | combustion turbine |
| CWIP | Construction Work in Progress |
| CY | calendar year (January through December) |
| DD | Dividend Distribution |
| DDC | Dividend Distribution Clause |
| *dec* | decrease, decrement, or decremental |
| DERBS | Dispatchable Energy Resource Balancing Service |
| DFS | Diurnal Flattening Service |
| DNR | Designated Network Resource |
| DOE | Department of Energy |
| DOI | Department of Interior |
| DSI | direct-service industrial customer or direct-service industry |
| DSO | Dispatcher Standing Order |
| EE | Energy Efficiency |

| | |
|---|---|
| EIM | Energy imbalance market |
| EIS | Environmental Impact Statement |
| EN | Energy Northwest, Inc. |
| ESA | Endangered Species Act |
| ESS | Energy Shaping Service |
| e-Tag | electronic interchange transaction information |
| FBS | Federal base system |
| FCRPS | Federal Columbia River Power System |
| FCRTS | Federal Columbia River Transmission System |
| FELCC | firm energy load carrying capability |
| FERC | Federal Energy Regulatory Commission |
| FOIA | Freedom Of Information Act |
| FORS | Forced Outage Reserve Service |
| FPS | Firm Power and Surplus Products and Services |
| FPT | Formula Power Transmission |
| FRP | Financial Reserves Policy |
| F&W | Fish & Wildlife |
| FY | fiscal year (October through September) |
| G&A | general and administrative (costs) |
| GARD | Generation and Reserves Dispatch (computer model) |
| GMS | Grandfathered Generation Management Service |
| GSP | Generation System Peak |
| GSR | Generation Supplied Reactive |
| GRSPs | General Rate Schedule Provisions |
| GTA | General Transfer Agreement |
| GWh | gigawatthour |
| HLH | Heavy Load Hour(s) |
| HOSS | Hourly Operating and Scheduling Simulator (computer model) |
| HYDSIM | Hydrosystem Simulator (computer model) |
| IE | Eastern Intertie |
| IM | Montana Intertie |
| *inc* | increase, increment, or incremental |
| IOU | investor-owned utility |
| IP | Industrial Firm Power |
| IPR | Integrated Program Review |
| IR | Integration of Resources |
| IRD | Irrigation Rate Discount |
| IRM | Irrigation Rate Mitigation |
| IRPL | Incremental Rate Pressure Limiter |
| IS | Southern Intertie |
| kcfs | thousand cubic feet per second |
| kW | kilowatt |
| kWh | kilowatthour |
| LDD | Low Density Discount |
| LGIA | Large Generator Interconnection Agreement |
| LLH | Light Load Hour(s) |

| | |
|---|---|
| LPP | Large Project Program |
| LTF | Long-term Firm |
| Maf | million acre-feet |
| Mid-C | Mid-Columbia |
| MMBtu | million British thermal units |
| MNR | Modified Net Revenue |
| MRNR | Minimum Required Net Revenue |
| MW | megawatt |
| MWh | megawatthour |
| NCP | Non-Coincidental Peak |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Corporation |
| NFB | **N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp) |
| NLSL | New Large Single Load |
| NMFS | National Marine Fisheries Service |
| NOAA Fisheries | National Oceanographic and Atmospheric Administration Fisheries |
| NOB | Nevada-Oregon border |
| NORM | Non-Operating Risk Model (computer model) |
| Northwest Power Act | Pacific Northwest Electric Power Planning and Conservation Act |
| NP-15 | North of Path 15 |
| NPCC | Pacific Northwest Electric Power and Conservation Planning Council |
| NPV | net present value |
| NR | New Resource Firm Power |
| NRFS | NR Resource Flattening Service |
| NRU | Northwest Requirements Utilities |
| NT | Network Integration |
| NTSA | Non-Treaty Storage Agreement |
| NUG | non-utility generation |
| NWPP | Northwest Power Pool |
| OATT | Open Access Transmission Tariff |
| O&M | operation and maintenance |
| OATI | Open Access Technology International, Inc. |
| OS | Oversupply |
| OY | operating year (August through July) |
| PDCI | Pacific DC Intertie |
| PF | Priority Firm Power |
| PFp | Priority Firm Public |
| PFx | Priority Firm Exchange |
| PNCA | Pacific Northwest Coordination Agreement |
| PNRR | Planned Net Revenues for Risk |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| POI | Point of Integration or Point of Interconnection |
| POR | Point of Receipt |

| | |
|---|---|
| PS | Power Services |
| PSC | power sales contract |
| PSW | Pacific Southwest |
| PTP | Point to Point |
| PUD | public or people's utility district |
| PW | WECC and Peak Service |
| RAM | Rate Analysis Model (computer model) |
| RCD | Regional Cooperation Debt |
| RD | Regional Dialogue |
| RDC | Reserves Distribution Clause |
| REC | Renewable Energy Certificate |
| Reclamation | U.S. Bureau of Reclamation |
| REP | Residential Exchange Program |
| REPSIA | REP Settlement Implementation Agreement |
| RevSim | Revenue Simulation Model |
| RFA | Revenue Forecast Application (database) |
| RHWM | Rate Period High Water Mark |
| ROD | Record of Decision |
| RPSA | Residential Purchase and Sale Agreement |
| RR | Resource Replacement |
| RRS | Resource Remarketing Service |
| RSC | Resource Shaping Charge |
| RSS | Resource Support Services |
| RT1SC | RHWM Tier 1 System Capability |
| SCD | Scheduling, System Control, and Dispatch Service |
| SCS | Secondary Crediting Service |
| SDD | Short Distance Discount |
| SILS | Southeast Idaho Load Service |
| Slice | Slice of the System (product) |
| T1SFCO | Tier 1 System Firm Critical Output |
| TCMS | Transmission Curtailment Management Service |
| TGT | Townsend-Garrison Transmission |
| TOCA | Tier 1 Cost Allocator |
| TPP | Treasury Payment Probability |
| TRAM | Transmission Risk Analysis Model |
| Transmission System Act | Federal Columbia River Transmission System Act |
| Treaty | Columbia River Treaty |
| TRL | Total Retail Load |
| TRM | Tiered Rate Methodology |
| TS | Transmission Services |
| TSS | Transmission Scheduling Service |
| UAI | Unauthorized Increase |
| UFT | Use of Facilities Transmission |
| UIC | Unauthorized Increase Charge |
| ULS | Unanticipated Load Service |
| USACE | U.S. Army Corps of Engineers |

| | |
|---|---|
| USBR | U.S. Bureau of Reclamation |
| USFWS | U.S. Fish & Wildlife Service |
| VER | Variable Energy Resource |
| VERBS | Variable Energy Resource Balancing Service |
| VOR | Value of Reserves |
| VR1-2014 | First Vintage Rate of the BP-14 rate period (PF Tier 2 rate) |
| VR1-2016 | First Vintage Rate of the BP-16 rate period (PF Tier 2 rate) |
| WECC | Western Electricity Coordinating Council |
| WSPP | Western Systems Power Pool |

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# 1. INTRODUCTION

## 1.1 Purpose of the Power Market Price Study

The Power Market Price Study explains the development of the power market price forecast, which incorporates natural gas pricing uncertainty and varying hydrology and load expectations. The power market price is used to forecast the value of secondary sales, the cost of anticipated balancing purchase and system augmentation purchases, Load Shaping and Demand rates, and the distribution of net revenues used to evaluate risk, among other values used by the Bonneville Power Administration (BPA) in ratemaking. This Study includes BPA's natural gas price forecast and electricity market price forecast.

## 1.2 How Market Price Results Are Used

Projections of electricity market prices are used for many aspects of setting power rates, including the quantitative analysis of risk presented in the Power and Transmission Risk Study, BP-20-FS-BPA-05. The Risk Study applies this distribution of future market price expectations to forecasts of BPA's loads and resources to create another distribution that assigns possible values to BPA's energy surplus or deficits. This resulting distribution is leveraged to quantify risk surrounding rate levels by reflecting the uncertainty in cost recovery attributed to the volatility of market price fundamentals.

Forecasts of electricity market prices are used in the Power Rates Study, BP-20-FS-BPA-01, in the calculations of:

- Prices for secondary energy sales and balancing power purchases
- Prices for augmentation purchases (if there is augmentation in the rate period)
- Load Shaping rates

- Load Shaping True-Up rate
- Resource Shaping rates
- Resource Support Services (RSS) rates
- Priority Firm Power (PF), Industrial Firm Power (IP), and New Resource Firm Power (NR) demand rates
- PF Tier 2 Balancing Credit
- PF Unused Rate Period High Water Mark (RHWM) Credit
- PF Tier 1 Equivalent rates
- PF Melded rates
- Balancing Augmentation Credit
- IP energy rates
- NR energy rates
- Energy Shaping Service (ESS) for New Large Single Load (NLSL) True-Up rate

# 2. FORECASTING MARKET PRICES

## 2.1 AURORA®

BPA uses the AURORA® (version 12.3.1064) model to forecast electricity market prices. For all assumptions other than those stated in Section 2.3 of this Study, the model uses data provided by the developer, EPIS LLC, in the database labeled North American DB 2017v3. AURORA® uses a linear program to minimize the cost of meeting load in the Western Electricity Coordinating Council (WECC), subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This cost approximates the price of electricity by assuming that all resources are centrally dispatched (the equivalent of cost-minimization in production theory) and that the marginal cost of producing electricity approximates the price.

### 2.1.1 Operating Risk Models

Uncertainty in each of the following variables is modeled as independent:

- WECC Loads
- Natural Gas Price
- Regional Hydroelectric Generation
- Pacific Northwest (PNW) and California Hourly Wind Generation
- Columbia Generating Station (CGS) Generation
- PNW Hourly Intertie Availability

Each statistical model calibrates to historical data to generate a distribution of future outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to AURORA®. Where applicable, that game also serves as input to BPA's Revenue Simulation model (RevSim). The prices from AURORA®, combined with the generation and expenses from RevSim, constitute one net revenue game. Because each risk model may not generate a full distribution of 3,200 games, where necessary a bootstrap is used to produce a full distribution. Each of the 3,200 draws from the joint distribution is identified uniquely such that each combination of load, hydrology, and other conditions is consistently applied between AURORA® prices and RevSim inventory levels.

### 2.2 R Statistical Software

The risk models used in AURORA® were developed in R (www.r-project.org), an open-source statistical software environment that compiles on several platforms. It is released under the GNU General Public License (GPL), a licensing system that specifies fair use for free software. R supports the development of risk models through an object-oriented, functional scripting environment; that is, it provides an interface for managing proprietary risk models and has a native random number generator useful for sampling distributions from any kernel. For the various risk models, the historical data is processed in R, the risk models are calibrated, and the risk distributions for input into AURORA® are generated in a unified environment.

### 2.3 AURORA® Model Inputs

AURORA® produces a single electricity price forecast as a function of its inputs. Thus, producing a given number of price forecasts requires that AURORA® be run that same number of times using different inputs. Risk models provide inputs to AURORA®, and the resulting distribution of market price forecasts represents a quantitative measure of market price risk. As described in the Power and Transmission Risk Study, BP-20-FS-BPA-05, 3,200 independent games from the joint distribution of the risk models serve as the basis for the 3,200 market price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute the market price forecast. Because AURORA® is an hourly model, the monthly prices in AURORA® are the simple average of the simulated hourly prices for that diurnal period. The following subsections describe the various inputs and risk models used in AURORA®.

### 2.3.1 Natural Gas Prices Used in AURORA®

The price of natural gas is the predominant factor in determining the dispatch cost of a natural gas-fired power generation plant. When natural gas-fired resources are the marginal unit (the least-cost generator available to supply an incremental unit of energy), the price of natural gas influences the price of electricity. Due to natural gas plants' frequent position as the marginal resource in the Pacific Northwest, falling natural gas prices will typically translate into a decrease in the market price for electricity (and vice versa). This effect varies seasonally; for example, electricity prices are much less sensitive to the price of natural gas in spring months, when hydroelectric generation is typically on the margin (*i.e.*, is the marginal unit), whereas in the winter gas-fired generation is typically on the margin and electricity prices are strongly correlated with the prevailing price of natural gas.

#### 2.3.1.1 Henry Hub Forecast

The foundation of natural gas prices in AURORA® is the price at Henry Hub, a trading hub near Erath, Louisiana. Cash prices at Henry Hub are used as the primary reference point for the North American natural gas market.

The average of the monthly forecast of Henry Hub prices is $2.57 per million British thermal units (MMBtu) for FY 2020 and $2.59 for FY 2021. See Table 1 in this Study.

#### 2.3.1.2 Methodology for Deriving AURORA® Zone Natural Gas Prices

Though Henry Hub is the point of reference for natural gas markets, AURORA® uses prices for 11 gas trading hubs in the WECC. Each natural gas plant modeled in AURORA® operates using fuel priced at a natural gas hub according to the zone in which the gas plant is located. Each zone is a geographic subset of the WECC. The prices at the other hubs are derived using their basis differentials (differences in prices between Henry Hub and the hub in question). Basis differentials reflect differences in the regional costs of supplying gas to meet demand after accounting for regional heterogeneity, including pipeline constraints, pipeline costs, regional production costs, and storage levels. The 11 Western hubs represent regional demand areas as well as three major supply basins that are the source for most of the natural gas delivered in the western United States.

Figure 1 shows the location of the 11 Western hubs. The forecast of basis differentials is derived from recent historical price differentials between Henry Hub and each of the other 11 trading hubs, along with projections of regional supply and demand. AECO, the primary trading hub in Alberta, Canada, is a main benchmark for Canadian gas prices. Sumas, Washington, is the primary hub for the delivery of gas from the Western Canada Sedimentary Basin (WCSB) into western Washington and western Oregon. Kingsgate is another gateway for WCSB gas and is the hub that is associated with the demand center in Spokane, Washington. Two Oregon hub locations, Stanfield and Malin, are included because major pipelines intersect at those locations. The Opal, Wyoming hub represents the collection of Rocky Mountain supply basins that supply gas to the Pacific Northwest and California. Pacific Gas and Electric (PG&E) Citygate represents demand centers in northern California. The San Juan Basin has its own hub, which primarily delivers gas to southern California. Topock, Arizona and Ehrenberg, Arizona represent intermediary locations between the San Juan Basin and demand centers in Southern California. For modeling and forecasting, the same price is used for both of these Arizona hubs, as they serve largely the same purpose and share the same underlying fundamentals. Topock and Ehrenberg are also receipt points for Permian gas, a producing area primarily located in western Texas. Inflows from the Permian are accounted for in the formulation of the 11 basis forecasts, but there is no Permian basis forecast or AURORA® zone. Finally, Southern California Citygate represents demand centers in southern California.

Once a forecast is prepared for the trading hubs' basis values, AURORA® assigns a forecast to each zone. Sumas, AECO, Kingsgate, Stanfield, Malin, and PG&E Citygate hubs are associated with zones in the Pacific Northwest, Northern California, and Canada. The Opal hub is associated with zones in Montana, Idaho, Wyoming, and Utah. San Juan, Topock, Ehrenberg, and Southern California Citygate hubs are associated with zones in Nevada, Southern California, Arizona, and New Mexico.

#### 2.3.1.3 The Basis Differential Forecast

Table 1 shows the basis differential forecast for the 11 trading hubs in the western United States used by AURORA®. Regional supply and demand fundamentals result in basis differential forecasts that are significantly below the Henry Hub benchmark.

#### 2.3.1.4 Natural Gas Price Risk

Addressing uncertainty regarding the price of natural gas is fundamental in evaluating electricity market price risk. As noted, when natural gas-fired generators deliver the marginal unit of electricity, as they frequently do in the Pacific Northwest, the price of natural gas largely determines the market price of electricity. Furthermore, as natural gas is an energy commodity, the price of natural gas is expected to fluctuate, and that volatility is an important source of market uncertainty.

BPA's natural gas risk model simulates daily natural gas prices, generates a distribution of 800 natural gas price forecasts, and presumes that the gas price forecast represents the median of the resulting distribution. Model parameters are estimated using historical Henry Hub natural gas prices. Once estimated, the parameters serve as the basis for simulated possible future Henry Hub price streams. This distribution of 800 simulated forecasts is randomly sampled to provide the Henry Hub natural gas price forecast input for each game in AURORA®.

The distribution of simulated natural gas prices is aggregated by month prior to being input to AURORA® because the TPP calculations and the Rate Analysis Model (RAM2020), Section 2.1 of the Power Rates Study, BP-20-FS-BPA-01, use only monthly electricity prices from AURORA®. Also, the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices. The 5th, 50th, and 95th percentiles of the forecast distribution are reported in Figure 2.

### 2.3.2 Load Forecasts Used in AURORA®

This Study uses the West Interconnect topology, which comprises 46 zones. It is one of the default zone topologies supplied with the AURORA® model and requires a load forecast for each zone.

#### 2.3.2.1 Load Forecast

AURORA® uses a WECC-wide, long-term load forecast as the base load forecast. Default AURORA® forecasts are used for areas outside the United States. BPA produced a monthly load forecast for each balancing authority in the WECC within the United States for the rate period. Default AURORA® forecasts are used for British Columbia and Mexico, and the Alberta Electric System Operator (AESO) 2017 Long Term Outlook load forecast is used for Alberta. As AURORA® uses a cut-plane topology (Figure 3) that does not directly correspond to the WECC balancing authorities (BA), it is necessary to map the balancing authority load forecast onto the AURORA® zones. The forecast by balancing authority is in Table 2.

#### 2.3.2.2 Load Risk Model

The load risk model uses a combination of three statistical methods to generate annual, monthly, and hourly load risk distributions that, when combined, constitute an hourly load forecast for use in AURORA®. When referring to the load model, this Study is referring to the combination of these models.

#### 2.3.2.3 Yearly Load Model

The yearly load model addresses variability in loads created by long-term economic patterns; that is, it incorporates variability at the annual level and captures business cycles and other departures from forecast that do not have impacts measurable at the sub-yearly level. The model is calibrated using historical annual loads for each control area in the WECC aggregated into the AURORA® zones defined in the West Interconnect topology. Furthermore, it assumes that load growth at the annual level is correlated across regions: the Pacific Northwest, California including Baja, Canada, the Rocky Mountain West, and the Southwest. It also assumes that load growth is correlated perfectly within them, guaranteeing that zones within each of these regions will follow similar annual variability patterns.

The model takes as given the history of annual loads at the balancing authority level, as provided in FERC Form 714 filings from 2001 to 2016 and aggregated into the regions described above. The model detrends and normalizes these annual aggregate load observations, so the sample space is composed of annual factors with an average of zero, and then uses a simple bootstrap with replacement to draw sets of random length observations from each year until enough draws are made to fill the forecast horizon. The model repeats this process 400 times, which generates 400 annual load factor time series used to generate simulated load growth patterns for each AURORA® zone.

#### 2.3.2.4 Monthly Load Risk

Monthly load variability accounts for seasonal uncertainty in load patterns. This seasonal load variation can potentially pose substantial risk to BPA revenue. Unseasonably hot summers in California, the Pacific Northwest, and the inland Southwest have the potential to exert substantial pressure on prices at Mid-C and thus are an important component of price risk.

In addition to an annual load forecast produced in average megawatts, AURORA® requires factors for each month of a forecast year that, when multiplied by the annual load forecast, yield the monthly loads in average megawatts. As such, the monthly load risk is represented by a distribution of vectors of 12 factors with a mean of 1. The monthly load risk model generates a distribution of these factors for the duration of the forecast period. The monthly load model takes as given the historical monthly load for each AURORA® zone, normalized by their annual averages, and uses deviations from the average normalized monthly factors as inputs.

A reduced-form Vector Autoregression (VAR) is then used to estimate each balancing authority's monthly deviation as a function of its own past deviations and the past deviations of all other modeled balancing authorities, as well as an error term. The model parameters and errors are then used to simulate 400 profiles of monthly deviations around the load forecast for the duration of the forecast horizon. The 400 profiles are randomly assigned to the 3200 AURORA® iterations.

#### 2.3.2.5 Hourly Load Risk

Hourly load risk embodies short-term price risk, as would be expected during cold snaps, warm spells, and other short-term phenomena. While this form of risk may not exert substantial pressure on monthly average prices, it generates variability within months and represents a form of risk that would not be captured in long-term business cycles or seasonal trends as reflected in the monthly and annual load risk models.

The hourly load model takes as inputs hourly loads for each AURORA® zone from 2001 to 2016. The model groups these hourly load observations by week of the year, and then normalizes the historical hourly loads by a rolling five-week average. The model then uses a simple bootstrap with replacement to draw sets of weeklong, hourly observations from a rolling range of three candidate weeks. For example, if the model is sampling for week 25 of a particular synthetic year, it may select observations from week 24, 25, or 26 from any of the historical observations. Draws are repeated until a full set of 8,952 hours is produced (8,760 hours plus 8 days to account for leap years and allow indexing to align with the correct starting day of the week for any year). The model repeats this process 50 times, which generates 50 year-long hourly load factor time series. These 50 draws are assigned randomly to the 3,200 AURORA® runs.

### 2.3.3 Hydroelectric Generation

Hydroelectric generation represents a substantial portion of the average generation in the PNW region, and fluctuations in its output can have a substantial effect on which generator is determined to be the marginal generator. Thus, PNW hydro generation is a primary driver of Mid-C electricity prices in AURORA®.

#### 2.3.3.1 PNW Hydro Generation Risk

The PNW hydroelectric generation risk factor reflects uncertainty regarding the timing and volume of streamflows. Given streamflows, BPA's Hydrosystem Simulator (HYDSIM) computes PNW hydroelectric generation amounts in average monthly values. *See* Power Loads and Resources Study, BP-20-FS-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 80 one-year-long records of PNW monthly hydroelectric generation, based on actual water conditions in the region from 1929 through 2008 as applied to the current hydro development and operational constraints. For each of the 3,200 games, the model samples one of the 80 water years for the first year of the rate period (FY 2020) from a discrete uniform probability distribution using R, the software described in Section 2.2 above. The model then selects the next historical water year for the following year of the rate period, FY 2021 *(i.e.,* if the model uses 1929 for FY 2020, then it selects 1930 for FY 2021). Should the model sample 2008 for FY 2020, it uses 1929 for FY 2021. The model repeats this process for each of the 3,200 games and guarantees a uniform distribution over the 80 water years. The resulting 3,200 water year combinations become AURORA® inputs.

#### 2.3.3.2 British Columbia (BC) Hydro Generation Risk

BC hydroelectric generation risk reflects uncertainty in the timing and volume of streamflows and the impacts on monthly hydroelectric generation in British Columbia. The risk model uses historical generation data from 1977 through 2008. The source of this information is Statistics Canada, a publication produced by the Canadian government. Because hydrological patterns in BC, including runoff and hydroelectric generation, are statistically independent of those in the PNW, BPA samples historical water years from BC independently from the PNW water year. As with the PNW, water years are drawn in sequence.

#### 2.3.3.3 California Hydro Generation Risk

California hydroelectric generation risk reflects uncertainty with respect to the timing and volume of streamflows and the impacts on monthly hydroelectric generation in California. Historical generation data from 1970 through 2008 was sourced from the California Energy Commission, the Federal Power Commission, and the U.S. Energy Information Administration

(EIA). As with the BC hydro risk model, and for the same reasons, California water years are drawn independently of PNW water years.

#### 2.3.3.4 Hydro Generation Dispatch Cost

With the introduction of negative variable costs for renewable resources, discussed in Section 2.3.7 below, reflecting the amounts of hydro energy available for curtailment (spillable hydro generation) in AURORA® becomes crucial to the frequency with which such renewable resources would provide the marginal megawatt of energy and set prices for the zone. To model the amount of spillable hydro generation available in the PNW, a separate HYDSIM study is employed to determine the incremental amount of water and energy that may be spilled before reaching total dissolved gas limits. *See* Power Loads and Resources Study, BP-20-FS-BPA-03, § 3.1.2.1.1. A relationship between average monthly hydro generation and these calculated levels of spillable hydro generation is estimated using an econometric model; the model is incorporated into AURORA® to set the level of spillable hydro generation on a monthly, game-by-game basis for hydro resources in the PNW.

The dispatch cost of spillable hydro generation retains the AURORA ® default of $1.74/MWh (2012 real dollars), while the remaining hydro generation (non-spillable hydro generation in the PNW and all other hydro generation across the Western Interconnection) dispatch cost is set to -$24/MWh (2016 real dollars), one dollar below the dispatch cost of wind. These assumptions ensure that, where available, approximated amounts of low-cost hydro generation are curtailed first. As the system moves down the resource supply stack, renewable resources are curtailed and zonal prices become negative, and finally, the remaining hydro generation and any must-run resources are curtailed.

#### 2.3.3.5 Hydro Shaping

AURORA® uses an algorithm to determine hydro generation availability. This algorithm produces an hourly hydroelectric generation value that depends on average daily and hourly load, the average monthly hydro generation (provided by HYDSIM), and the output of any resource defined as "must run." Several constraints give the user control over minimum and maximum generation levels, the hydro shaping factor (*e.g.,* the extent to which it follows load), and so on. AURORA® uses the default hydro shaping logic with two exceptions: minimum generation levels and the hydro-shaping factor.

##### 2.3.3.5.1 Hydro Minimum Generation Levels

Output from AURORA® suggests that its hydro-shaping algorithm generates a diurnal generation pattern that is inappropriate during high water; that is, the ratio of HLH generation to LLH generation is too high. It is recognized that high water compromises the ability of the hydro system to shape hydro between on-peak and off-peak hours. By default, AURORA® limits minimum generation to 44 percent of nameplate capacity during May and June, but operations data suggest that this system minimum generation can be as high as 75 percent of nameplate capacity during high water months. To address this difference, a separate model is used to implement the minimum generation constraints. These constraints generally restrict the minimum generation to a higher percentage of nameplate capacity than default AURORA® settings and reflect observed constraints on the degree to which the system can more realistically shape hydroelectric generation.

To implement this ratio in AURORA®, the model limits the minimum hydro generation in each month to the expected ratio of minimum generation to nameplate capacity based on an econometric model.

#### 2.3.3.5.2 Shaping Factor for PNW Hydro Resources

In AURORA®, spillable hydro generation (described in Section 2.3.3.4 above) is locked into a flat shape throughout the day, which in turn substantially reduces the amount of hydro generation shaped into on-peak hours in the PNW. While the adjustment to minimum generation levels described above prevents the model from over-shaping hydro generation during high streamflow conditions, additional modifications to the logic are required to increase shaping during normal and lower streamflow conditions. First, an econometric model estimates the historical relationship between monthly average hydro generation and the ratio of HLH-to-LLH hydro generation using Federal hydro system operations data from July 2008 to June 2018. Second, the model is implemented in AURORA® to set a target HLH-to-LLH hydro generation ratio (Target Ratio) based on the relevant expected monthly hydro generation. Finally, a hydro-shaping factor value necessary to achieve the Target Ratio is calculated and applied to PNW hydro resources.

### 2.3.4 Hourly Shape of Wind Generation

AURORA® models wind generation as a must-run resource with a minimum capacity of 40 percent. This assumption implies that, for any given hour, AURORA® dispatches 40 percent of the available capacity independent of economic fundamentals and dispatches the remaining 60 percent as needed. During the BP-20 rate period, BPA expects a little over 8,000 MW (nameplate) of wind capacity to operate in the PNW. The large amount of wind in the PNW (and throughout the rest of the WECC) affects the market price forecast at Mid-C by changing the generating resource used to determine the marginal price. Modeling wind generation on an hourly basis better captures the operational impacts that changes in wind generation can have on the marginal resource compared to using average monthly wind generation values. The hourly granularity for wind generation allows the price forecast more accurately to reflect the economic decision faced by thermal generators. Each hour, generators must decide whether to operate in a volatile market in which the marginal price can be below the cost of running the thermal generator but start-up and shut-off constraints could prevent the generator from shutting down.

### 2.3.4.1 PNW and California Hourly Wind Generation Risk

The PNW and California Hourly Wind Generation Risk Models simulate the uncertainty in wind generation output. The uncertainty is derived by averaging the observed output of wind plants within the respective balancing authority area for each hour and converting the data into hourly capacity factors. The source of these data is recent 10-year historical periods from BPA's external website, www.bpa.gov, and from CAISO daily renewable energy reports. The models implement a Markov Chain Monte Carlo (MCMC) rejection sampling algorithm to generate synthetic series of wind generation data. This technique allows the production of statistically valid artificial wind series that preserve the higher-order moments of observed wind time series. Through this process, the model creates 30 time series for both the PNW and California, each of which includes 8,784 hours, to create a complete wind year for each geographic area. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select AURORA® zones. This approach captures potential variations in annual, monthly, and hourly wind generation.

### 2.3.5 Solar Plant Generation

For photovoltaic solar resources built in or after 2016 (including future generic builds), BPA uses hourly generation profiles for three general technology types: fixed-axis rooftop, fixed-axis utility scale, and single-axis tracking. The profiles were produced using NREL's PVWatts calculator for each AURORA® zone. This enables modeling of single-axis tracking systems where the default database lacks generation profiles, distinguishing between utility scale and rooftop generation profiles, as well as capturing the latest trends in inverter-to-panel size ratios (a characteristic that strongly influences generation profiles), while keeping a consistent methodology across the WECC. All other solar generators rely on AURORA® default generation profiles.

### 2.3.6 Thermal Plant Generation

The thermal generation units in AURORA® often drive the marginal unit price, whether the units are natural gas, coal, or nuclear. With the exception of CGS generation and minimum operating levels of natural gas and coal plants, operation of thermal resources in AURORA® is based on the EPIS-supplied database labeled North American DB 2017v3.

The minimum operating level is the lowest amount of power a plant can generate while the plant is on, usually expressed in percentage of total plant capacity. The EPIS-supplied database contained substantial amounts of natural gas and coal plant capacity with minimum operating levels of 0 percent, while such plants tend to have minimum operating levels ranging from 20-60 percent. Accordingly, for all coal and natural gas plants in the Western Interconnection that were built prior to 2018, we have updated the minimum operating levels consistent with a recent California Energy Commission study that estimated average minimum operating levels for multiple fuel and technology types using actual generation levels from plants in the western United States.[1]

#### 2.3.6.1 Columbia Generating Station Generation Risk

The CGS Generation Risk Model simulates monthly variability in the output of CGS such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Power Loads and Resources Study, BP-20-FS-BPA-03, Section 3.1.3. The simulated results vary from the maximum output of the plant to zero output. The frequency distribution of the

[1] Paul Deaver, *Updating Thermal Power Plant Efficiency Measures and Operational Characteristics for Production Cost Modeling*, California Energy Commission (2019), https://ww2.energy.ca.gov/2019publications/CEC-200-2019-001/CEC-200-2019-001.pdf.

simulated CGS output is negatively skewed: the median is higher than the mean. This reflects the reality that thermal plants such as CGS typically operate at higher-than-average output levels, but occasional forced outages result in lower monthly average output levels.

The output of the CGS Generation Risk Model feeds both RevSim (*see* the Power and Transmission Risk Study, BP-20-FS-BPA-05, § 4.1.1) and AURORA®, where the results of the model are converted into equivalent forced outage rates and applied to the nameplate capacity of CGS for each of 3,200 games.

### 2.3.7 Generation Additions and Retirements

As a result of state Renewable Portfolio Standards (RPS) and Federal tax credit policies, renewable resource additions have been substantial during recent years. Additionally, installation of behind-the-meter resources, namely, rooftop solar photovoltaic panels, continues to grow significantly. Favorable net energy metering policies in California and declining installation costs throughout the WECC region are likely to reinforce this trend for the near future. Two main sets of data are used to quantify this growth.

First, data from the EIA database of planned and sited additions and retirements over the horizon of the rate period is referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to create a set of planned additions and retirements in AURORA®. BPA then employs a set of AURORA® LT energy min constraints in a Long-Term Capacity Expansion study that ensures a sufficient number of generic renewable resources are added to this stack to meet state renewable portfolio standards (including Alberta's 30 percent target by 2030). The energy min constraint forces the model to build additional resources from a list of candidate resources, based on whichever potential resource has the lowest overall expected cost, if the existing fleet fails to produce enough energy to meet the constraint. AURORA® default overnight capital costs for new wind and solar plants are blended with consultant estimates to produce values in line with estimates from the Northwest Power and Conservation Council's Seventh Power Plan Draft Mid-term Assessment.

Second, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California, Nevada, Arizona, and New Mexico were included from the California Energy Commission forecast, published February 2018, and various utility Integrated Resource Plans (IRPs) published between 2015 and 2017. The corresponding zonal load forecasts were adjusted to keep projected net load (load minus behind-the-meter generation) aligned with BPA's load forecasts. Resources from both sets of data were included in the resource table of AURORA®. Additionally, energy storage resources have been added to meet California's storage targets. The storage resource attributes such as online dates, duration, capacity, peak credit, and utility region are consistent with California Public Utilities Commission assumptions specified for its IRP process.

Finally, AURORA® has logic capable of adding and retiring resources based upon economics. In a Long-Term Capacity Expansion Study, AURORA® generates a catalogue of resource additions and retirements consistent with long-term equilibrium: it (1) identifies any resources whose operating revenue is insufficient to cover their fixed and variable costs of operation and retires a subset of the least economic resources, subject to annual retirement limits modified by BPA; and (2) selects plants from a candidate list of additions whose operating revenue would cover their fixed and variable costs and adds them to the resource base. AURORA® thus ensures that resources are added when economic circumstances justify. The retirement limits allow for retirement of one additional medium-size power plant per pool, per year, above any planned retirements BPA incorporates. AURORA® adds no new thermal resources to the PNW during the BP-20 rate period.

### 2.3.8 WECC Renewable Resource Dispatch Cost

The substantial growth of renewables across the Western Interconnection increases the likelihood that such resources will provide the marginal megawatt of energy and, when in market-based regions, set prices. Power purchase agreements, renewable energy credits, production tax credits, and other compensation mechanisms allow renewable resources to offer energy at negative prices and still earn revenue from production. Additionally, load-serving entities may operate renewable resources to satisfy RPS requirements and would be expected to offer such resources' generation at the replacement cost of renewable energy (*i.e.*, if the operator had to curtail some amount of renewable output, the operator would be legally responsible to procure additional renewable energy sufficient to meet its RPS requirement). To approximate such behavior in AURORA®, all wind resource dispatch costs are set to -$23/MWh (2016 real dollars), a reflection of an appropriate offer price if the resource receives the Federal production tax credit. Lacking a widely available and transparent supplemental income figure for solar resources analogous to the Federal production tax credit for wind resources, BPA relies on the simplifying assumption that wind and solar resource dispatch costs are comparable. The AURORA® default dispatch cost of solar resources is also set to -$23/MWh (2016 real dollars).

### 2.3.9 Transmission Capacity Availability

In AURORA®, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 3 shows the AURORA® representation of the major transmission interconnections for the West Interconnect topology. The transmission path ratings for the Alternating-Current or California-Oregon Intertie (AC Intertie or COI), the Direct-Current Intertie (DC Intertie), and the British Columbia Intertie (BC Intertie) are based on historical intertie reports posted on the BPA OASIS website from 2009 through 2018. The ratings for the rest of the interconnections are based on North American DB 2017v3.

#### 2.3.9.1 PNW Hourly Intertie Availability Risk

PNW hourly intertie risk represents uncertainty in the availability of transmission capacity on each of three interties that connect the PNW with other regions in the WECC: AC Intertie, DC Intertie, and BC Intertie. The PNW hourly intertie risk model implements a Markov Chain duration model based on observed data from 2009 through 2018. The data comprise observed transmission path ratings and the duration of those ratings for both directions on each line.

The model begins with an observed path rating and duration from the historical record. It samples the proximate path rating using a Markov Chain that has been estimated with observed data. Then it samples a duration to associate with that rating based on the set of observed, historical durations associated with that specific rating and conditioned on the relevant season (a rolling 3-month period). This process repeats until an 8,784-hour record has been constructed. The model generates 100 artificial records. Path ratings are rounded to avoid a Markov Chain that is too sparse to effectively generate synthetic profiles.

For each of 3,200 games, each intertie has a single record that is independently selected from the associated set of 100 records. The outage rate is applied to the Link Capacity Shape, a factor that determines the amount of power that can be moved between zones in AURORA® for the associated intertie. By using this method, quantification of this risk results in the average of the simulated outcomes being equal to the expected path ratings in the historical record, as well as preserving observed seasonal path rating variation.

### 2.3.10 California Carbon Pricing

The California Air Resources Board established a carbon market by placing limits on $CO_2$ emissions and requiring entities in a number of sectors, including electricity, to purchase sufficient allowances (shares of the total $CO_2$ limit) in quarterly auctions to cover their emissions. These auctions are subject to a floor price set to $15.62 per metric ton of $CO_2$ emissions in 2019 (nominal) and escalating at 5 percent annually plus the rate of inflation. In the California electricity market, resources are allowed to incorporate the costs of purchasing $CO_2$ allowances in their offer, so prices should reflect a carbon adder roughly equal to the marginal resource's emission rate multiplied by the $CO_2$ allowance price. Out-of-state electricity producers wishing to export energy to California are subject to a default emission rate of 0.428 metric tons per megawatthour unless the producer qualifies for a lower rate more specific to its resources (specified sources).

The California carbon market mechanisms are reflected in AURORA® by applying the auction floor prices to California resources using AURORA® default $CO_2$ emission rates for each resource to establish an incremental carbon emission cost addition, which is incorporated into dispatch and commitment logic. Consequently, if a California resource provides the marginal megawatt of energy and sets a zonal price, the price will include the additional cost of $CO_2$ emissions tied to producing that megawatt of energy (the specific resource $CO_2$ emission rate multiplied by the cost of $CO_2$ emissions). Using BPA's inflation forecast, the auction floor prices are calculated to be $15.62, $16.78, and $18.01 per metric ton of $CO_2$ emissions (nominal) for calendar years 2019, 2020, and 2021, respectively.

Additionally, wheeling costs on all transmission lines going into California are subject to an adder of the default emission rate of 0.428 metric tons per megawatthour at the auction floor prices. Recognizing that California has historically imported substantial amounts of low or zero-carbon emission energy from the PNW, and that this practice is likely to continue for the BP-20 rate period, estimates of future low or zero-carbon emission flows are exempted from the carbon emission adders on the AC and DC interties to California. These estimates were produced by taking annual average low or zero emission flows from the PNW to California over the last three years, as reported by the California Energy Commission, and using monthly average hydro and wind generation levels to shape the annual amount to expected monthly levels. This method results in a little under 2000 megawatts of transmission capacity on the AC and DC lines being exempt from the carbon price adder. Overall, the changes tend to increase projected north-to-south flows on the affected transmission lines, and moderately increase forecast prices at Mid-C.

#### 2.3.11 Alberta Carbon Pricing

Beginning in 2018, Alberta applied a carbon price of $30 per metric ton of $CO_2$ emissions (nominal; this value is set to increase to $40 per metric ton of CO2 emissions in 2021) to incremental emissions above those of the most efficient natural gas combined-cycle plant. The threshold for establishing what counts as incremental emissions above the most efficient plant is set to decline by 1 percent annually. Accordingly, Alberta thermal resources' $CO_2$ emission rates in AURORA® are updated to reflect their incremental emissions above the threshold and are subject to the appropriate carbon emission price.

### 2.4 Market Price Forecasts Produced By AURORA®

Two electricity price forecasts are created using AURORA®. The market price forecast uses hydro generation data for all 80 water years, and the critical water forecast uses hydro generation for only the critical water year, 1937. Figure 4 shows the FY 2020 through FY 2021 monthly average HLH and LLH prices from the market price forecast. Figure 5 shows the FY 2020 and

FY 2021 monthly average HLH and LLH prices from the critical water forecast.  The BP-20 rate case average Mid-C price from the market price forecast is $19.26/MWh (nominal).

As stated previously, these projections of market prices for electricity are used for many aspects of setting power rates, including the quantitative analysis of risk presented in the Power and Transmission Risk Study, BP-20-FS-BPA-05, and numerous components of the Power Rates Study, BP-20-FS-BPA-01.

**DOCUMENTATION**

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**Table 1: Cash Prices at Henry Hub and Basis Differentials (nominal $/MMBtu)**

| | FY 2020 | FY 2021 |
|---|---|---|
| Henry | $2.57 | $2.59 |
| AECO | -$1.27 | -$1.12 |
| Kingsgate | -$0.60 | -$0.65 |
| Malin | -$0.38 | -$0.40 |
| Opal | -$0.44 | -$0.45 |
| PG&E | $0.36 | $0.33 |
| SoCal City | $1.04 | $0.25 |
| Ehrenberg | -$0.25 | -$0.30 |
| Topock | -$0.25 | -$0.30 |
| San Juan | -$0.56 | -$0.56 |
| Stanfield | -$0.47 | -$0.49 |
| Sumas | -$0.38 | -$0.46 |

## Table 2: Control Area Load Forecast

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Table 2: Control Area Load Forecast (MWh)** | | | | | | | | | | | | | | |
| 2 | **Date** | **APS** | **AVA** | **BPA** | **CHPD** | **CISO** | **DOPD** | **EPE** | **GCPD** | **IID** | **IPC** | **LDWP** | **NEVP** | **NWE** | **PAC** |
| 3 | **Oct-19** | 2611522 | 1025566 | 4178508 | 139291 | 18184888 | 118730 | 682869 | 370455 | 307882 | 1219155 | 2312700 | 1861196 | 869150 | 5722455 |
| 4 | **Nov-19** | 2242495 | 1154047 | 4889341 | 154954 | 17089214 | 152343 | 624120 | 374003 | 258001 | 1309665 | 2153717 | 1739023 | 924042 | 5983440 |
| 5 | **Dec-19** | 2507170 | 1318568 | 5435806 | 171585 | 18083520 | 189922 | 678825 | 424997 | 268451 | 1548773 | 2318540 | 1908138 | 1034615 | 6416573 |
| 6 | **Jan-20** | 2514433 | 1276186 | 5336900 | 171282 | 17835540 | 190444 | 682821 | 424718 | 263261 | 1499346 | 2320442 | 1891608 | 1030125 | 6521328 |
| 7 | **Feb-20** | 2235354 | 1122860 | 4714774 | 146922 | 16335429 | 149511 | 619388 | 362813 | 240889 | 1313406 | 2109050 | 1685344 | 939990 | 5889520 |
| 8 | **Mar-20** | 2343414 | 1099652 | 4552780 | 144616 | 17433726 | 124259 | 637433 | 369023 | 260038 | 1249723 | 2278330 | 1755489 | 935996 | 5891325 |
| 9 | **Apr-20** | 2368809 | 1012746 | 4355979 | 135208 | 16831840 | 115360 | 641992 | 383047 | 262430 | 1241705 | 2180864 | 1676008 | 835659 | 5545032 |
| 10 | **May-20** | 2725627 | 1020395 | 4384664 | 134106 | 18110546 | 120066 | 705396 | 411760 | 336483 | 1487523 | 2344429 | 2007685 | 841227 | 5624616 |
| 11 | **Jun-20** | 3023696 | 1005505 | 4368237 | 131154 | 19373068 | 118689 | 789144 | 426233 | 389908 | 1622950 | 2517195 | 2449234 | 853534 | 5868016 |
| 12 | **Jul-20** | 3585844 | 1096328 | 4606888 | 139470 | 22114722 | 141547 | 882148 | 467783 | 449587 | 1991565 | 2803991 | 2961172 | 968154 | 6611526 |
| 13 | **Aug-20** | 3549495 | 1096018 | 4506250 | 139469 | 22433434 | 142062 | 880854 | 462234 | 446254 | 1854653 | 2856475 | 2842856 | 937685 | 6464735 |
| 14 | **Sep-20** | 3041753 | 983886 | 4107434 | 131978 | 20243074 | 116929 | 760026 | 393570 | 386786 | 1442010 | 2633171 | 2271378 | 835198 | 5590506 |
| 15 | **Oct-20** | 2643909 | 1030358 | 4211834 | 139994 | 18148332 | 120408 | 690845 | 378145 | 309540 | 1225203 | 2341911 | 1871042 | 874677 | 5758836 |
| 16 | **Nov-20** | 2274882 | 1158828 | 4923737 | 155656 | 17060886 | 154021 | 632096 | 381672 | 259982 | 1315714 | 2181595 | 1748869 | 929568 | 6019822 |
| 17 | **Dec-20** | 2539557 | 1323338 | 5471026 | 172286 | 18047724 | 191600 | 686800 | 432647 | 270362 | 1554821 | 2347777 | 1917985 | 1040141 | 6452954 |
| 18 | **Jan-21** | 2539328 | 1280569 | 5358843 | 171799 | 17830422 | 192003 | 692704 | 432347 | 263564 | 1502646 | 2355717 | 1900082 | 1037183 | 6545550 |
| 19 | **Feb-21** | 2243417 | 1106397 | 4661217 | 147194 | 16104111 | 149135 | 603951 | 386387 | 244574 | 1287565 | 2123687 | 1655276 | 910613 | 5824775 |
| 20 | **Mar-21** | 2368309 | 1104014 | 4573549 | 145130 | 17430070 | 125817 | 647316 | 376612 | 260378 | 1253023 | 2313038 | 1763964 | 943054 | 5915546 |
| 21 | **Apr-21** | 2393704 | 1017097 | 4376455 | 135721 | 16830382 | 116919 | 651875 | 390616 | 262739 | 1245005 | 2214304 | 1684483 | 842717 | 5569253 |
| 22 | **May-21** | 2737424 | 1024735 | 4405185 | 134618 | 18116650 | 121624 | 715279 | 419310 | 335889 | 1491283 | 2379968 | 2010821 | 848285 | 5648838 |
| 23 | **Jun-21** | 3035493 | 1009835 | 4388735 | 131665 | 19374562 | 120248 | 799027 | 433763 | 388662 | 1626710 | 2554953 | 2452370 | 860592 | 5892238 |
| 24 | **Jul-21** | 3597641 | 1100647 | 4627745 | 139981 | 22106208 | 143106 | 892031 | 475293 | 447614 | 1995325 | 2845441 | 2964308 | 975212 | 6635748 |
| 25 | **Aug-21** | 3561292 | 1100326 | 4526958 | 139979 | 22423756 | 143620 | 890737 | 469724 | 444319 | 1858413 | 2898591 | 2845992 | 944743 | 6488957 |
| 26 | **Sep-21** | 3053550 | 988184 | 4127546 | 132487 | 20241392 | 118487 | 769909 | 401041 | 385575 | 1445770 | 2672392 | 2274515 | 842256 | 5614728 |

## Table 2:  Control Area Load Forecast (cont.)

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | **Table 2 (cont): Control Area Load Forecast (MWh)** | | | | | | | | | | | | | | |
| 28 | **Date** | **PGE** | **PNM** | **PSC** | **PSE** | **SCL** | **SMUD** | **SPR** | **SRP** | **TEP** | **TID** | **TPWR** | **WACM** | **WALC** | **WAUW** |
| 29 | **Oct-19** | 1646116 | 851405 | 3403784 | 2007906 | 813413 | 1251804 | 1020972 | 2391317 | 1167759 | 213693 | 386259 | 2073804 | 727604 | 73259 |
| 30 | **Nov-19** | 1792090 | 855035 | 3457002 | 2291736 | 904267 | 1223596 | 1041080 | 2072010 | 1109576 | 191324 | 453684 | 2130560 | 657053 | 82881 |
| 31 | **Dec-19** | 2011193 | 963298 | 3877906 | 2514280 | 952949 | 1395383 | 1151192 | 2324724 | 1209303 | 201294 | 499463 | 2355340 | 739645 | 89947 |
| 32 | **Jan-20** | 1953441 | 951098 | 3820682 | 2518629 | 989135 | 1369803 | 1122676 | 2371495 | 1205408 | 196282 | 494318 | 2310065 | 730121 | 92815 |
| 33 | **Feb-20** | 1757164 | 839975 | 3478864 | 2281010 | 891599 | 1207256 | 1019640 | 2012387 | 1115386 | 175271 | 454051 | 2166907 | 651720 | 83826 |
| 34 | **Mar-20** | 1721100 | 870414 | 3516285 | 2195790 | 872678 | 1250418 | 1052167 | 2179134 | 1135214 | 190239 | 438416 | 2181846 | 680641 | 81606 |
| 35 | **Apr-20** | 1608029 | 818407 | 3280897 | 2000293 | 815923 | 1168772 | 995753 | 2187344 | 1080992 | 187019 | 398680 | 2036369 | 685523 | 71343 |
| 36 | **May-20** | 1613392 | 827484 | 3327823 | 1878679 | 784730 | 1257310 | 1028193 | 2581496 | 1248644 | 227077 | 372253 | 2097183 | 779707 | 73572 |
| 37 | **Jun-20** | 1556246 | 899953 | 3510982 | 1821929 | 758333 | 1455471 | 1049998 | 2948598 | 1431815 | 245899 | 354286 | 2197671 | 877678 | 76447 |
| 38 | **Jul-20** | 1747095 | 1024975 | 4091292 | 1899534 | 783586 | 1712572 | 1166308 | 3391629 | 1628426 | 276502 | 362367 | 2458048 | 941697 | 94245 |
| 39 | **Aug-20** | 1772572 | 1014301 | 3951043 | 1937294 | 780446 | 1691610 | 1165798 | 3353741 | 1608493 | 273730 | 369946 | 2419989 | 893409 | 86438 |
| 40 | **Sep-20** | 1583764 | 876232 | 3342386 | 1851714 | 753095 | 1443905 | 1033900 | 2876244 | 1415126 | 243946 | 356805 | 2091059 | 805969 | 75973 |
| 41 | **Oct-20** | 1648696 | 859063 | 3416678 | 2014603 | 815727 | 1249886 | 1028541 | 2430626 | 1185532 | 211716 | 387224 | 2084966 | 735355 | 73259 |
| 42 | **Nov-20** | 1794669 | 862703 | 3469896 | 2298433 | 906581 | 1221868 | 1048650 | 2111230 | 1127208 | 189805 | 454649 | 2141640 | 664783 | 82881 |
| 43 | **Dec-20** | 2013772 | 971232 | 3890800 | 2520977 | 955263 | 1392496 | 1158761 | 2363853 | 1227183 | 199565 | 500428 | 2366338 | 747354 | 89947 |
| 44 | **Jan-21** | 1955554 | 956391 | 3829121 | 2522256 | 990388 | 1371491 | 1128876 | 2408765 | 1225008 | 194536 | 494840 | 2320984 | 737810 | 92815 |
| 45 | **Feb-21** | 1701264 | 838307 | 3400519 | 2226877 | 869325 | 1181923 | 1007799 | 2107538 | 1101822 | 176115 | 441929 | 2115070 | 653783 | 81970 |
| 46 | **Mar-21** | 1723214 | 875509 | 3524724 | 2199417 | 873931 | 1252368 | 1058368 | 2216227 | 1154648 | 188603 | 438939 | 2192609 | 688289 | 81606 |
| 47 | **Apr-21** | 1610143 | 823375 | 3289336 | 2003921 | 817176 | 1170901 | 1001953 | 2224348 | 1100295 | 185443 | 399203 | 2047056 | 693151 | 71343 |
| 48 | **May-21** | 1615506 | 832474 | 3336261 | 1882307 | 785983 | 1259244 | 1034393 | 2611933 | 1268361 | 225586 | 372775 | 2107793 | 787315 | 73572 |
| 49 | **Jun-21** | 1558359 | 905122 | 3519421 | 1825556 | 759586 | 1456971 | 1056198 | 2978966 | 1451984 | 244032 | 354809 | 2208208 | 885266 | 76447 |
| 50 | **Jul-21** | 1749208 | 1030450 | 4099731 | 1903161 | 784839 | 1713508 | 1172508 | 3421927 | 1649079 | 274029 | 362890 | 2468511 | 949265 | 94245 |
| 51 | **Aug-21** | 1774686 | 1019750 | 3959482 | 1940922 | 781699 | 1692592 | 1171999 | 3383970 | 1629100 | 271304 | 370469 | 2430380 | 900958 | 86438 |
| 52 | **Sep-21** | 1585877 | 881343 | 3350824 | 1855342 | 754348 | 1445431 | 1040100 | 2906403 | 1435262 | 242100 | 357328 | 2101379 | 813498 | 75973 |

**Figure 1: Basis Locations**

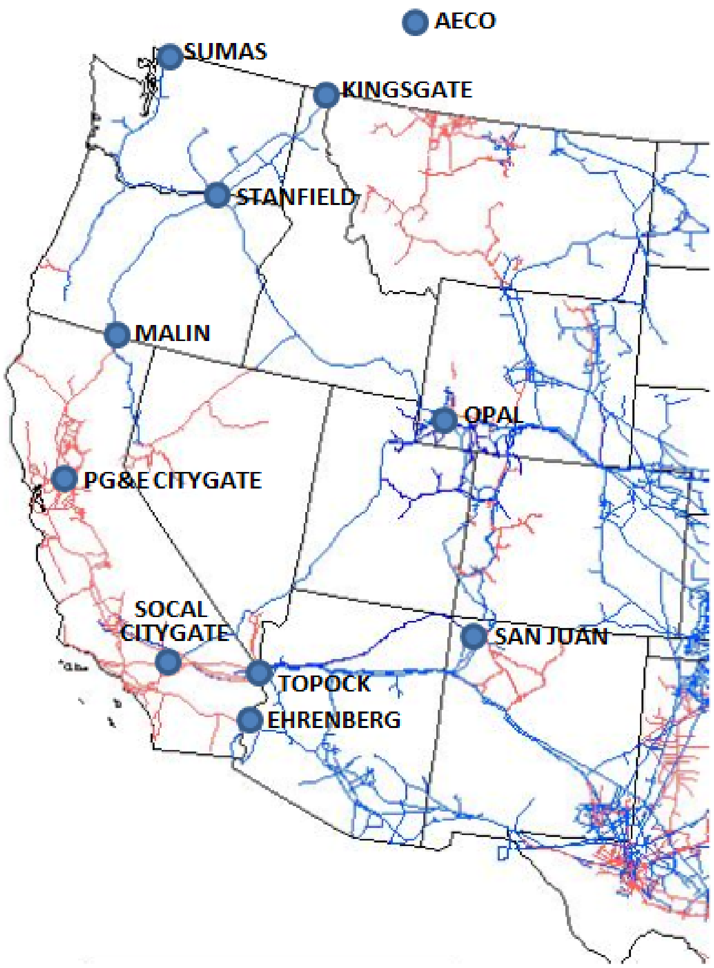
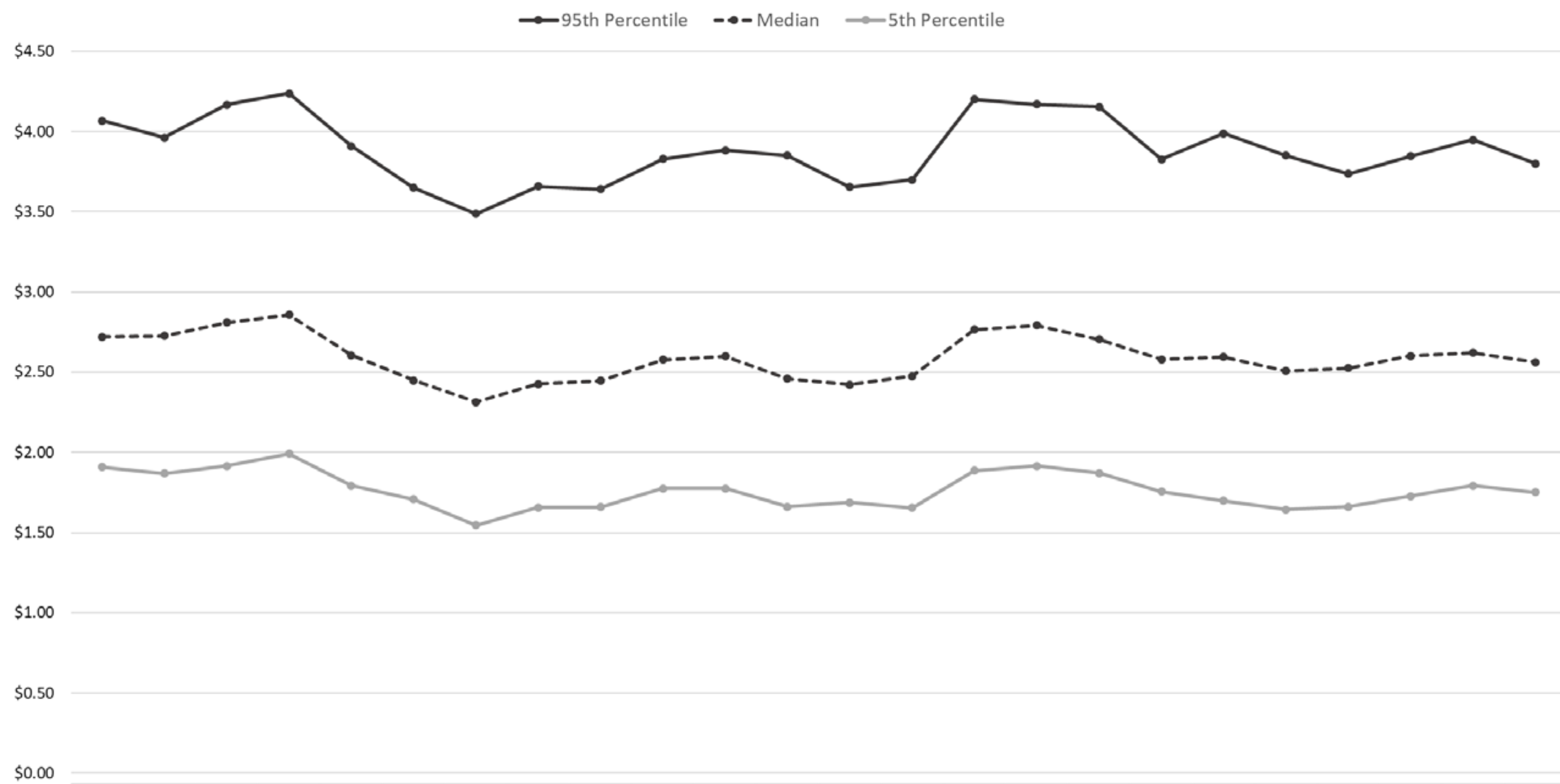


**Figure 2: Natural Gas Price Risk Model Percentiles**




| | Oct-19 | Nov-19 | Dec-19 | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 95th Percentile | 4.07 | 3.96 | 4.17 | 4.24 | 3.91 | 3.65 | 3.49 | 3.66 | 3.64 | 3.83 | 3.88 | 3.85 | 3.65 | 3.70 | 4.20 | 4.17 | 4.16 | 3.83 | 3.99 | 3.85 | 3.74 | 3.85 | 3.95 | 3.80 |
| Median | 2.72 | 2.73 | 2.81 | 2.86 | 2.61 | 2.45 | 2.31 | 2.43 | 2.45 | 2.58 | 2.60 | 2.46 | 2.42 | 2.47 | 2.77 | 2.79 | 2.70 | 2.58 | 2.59 | 2.51 | 2.53 | 2.60 | 2.62 | 2.56 |
| 5th Percentile | 1.91 | 1.87 | 1.92 | 1.99 | 1.79 | 1.71 | 1.55 | 1.66 | 1.66 | 1.78 | 1.77 | 1.66 | 1.69 | 1.65 | 1.89 | 1.91 | 1.87 | 1.75 | 1.70 | 1.64 | 1.66 | 1.73 | 1.79 | 1.75 |

**Figure 3: AURORA® Zonal Topology**

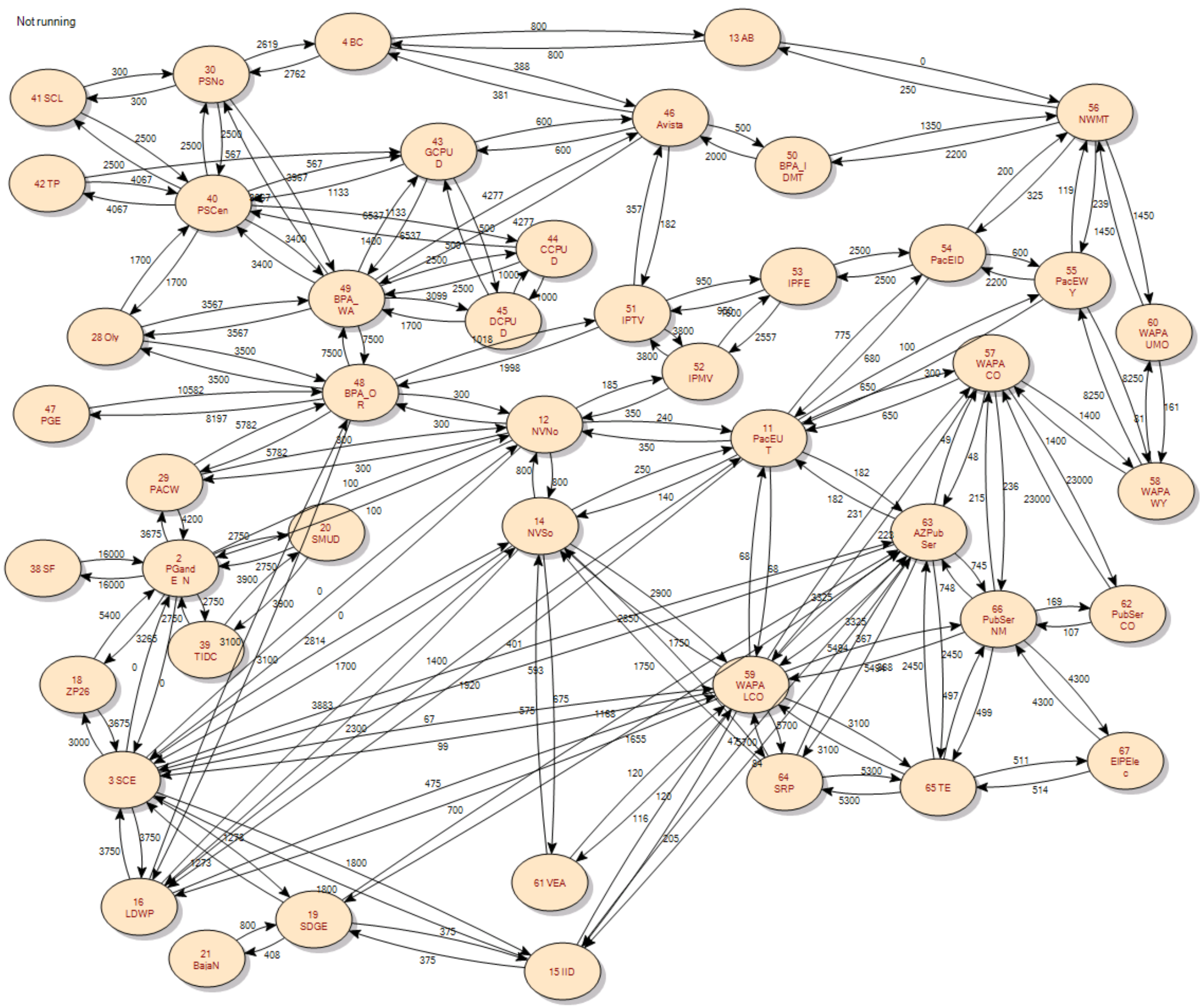
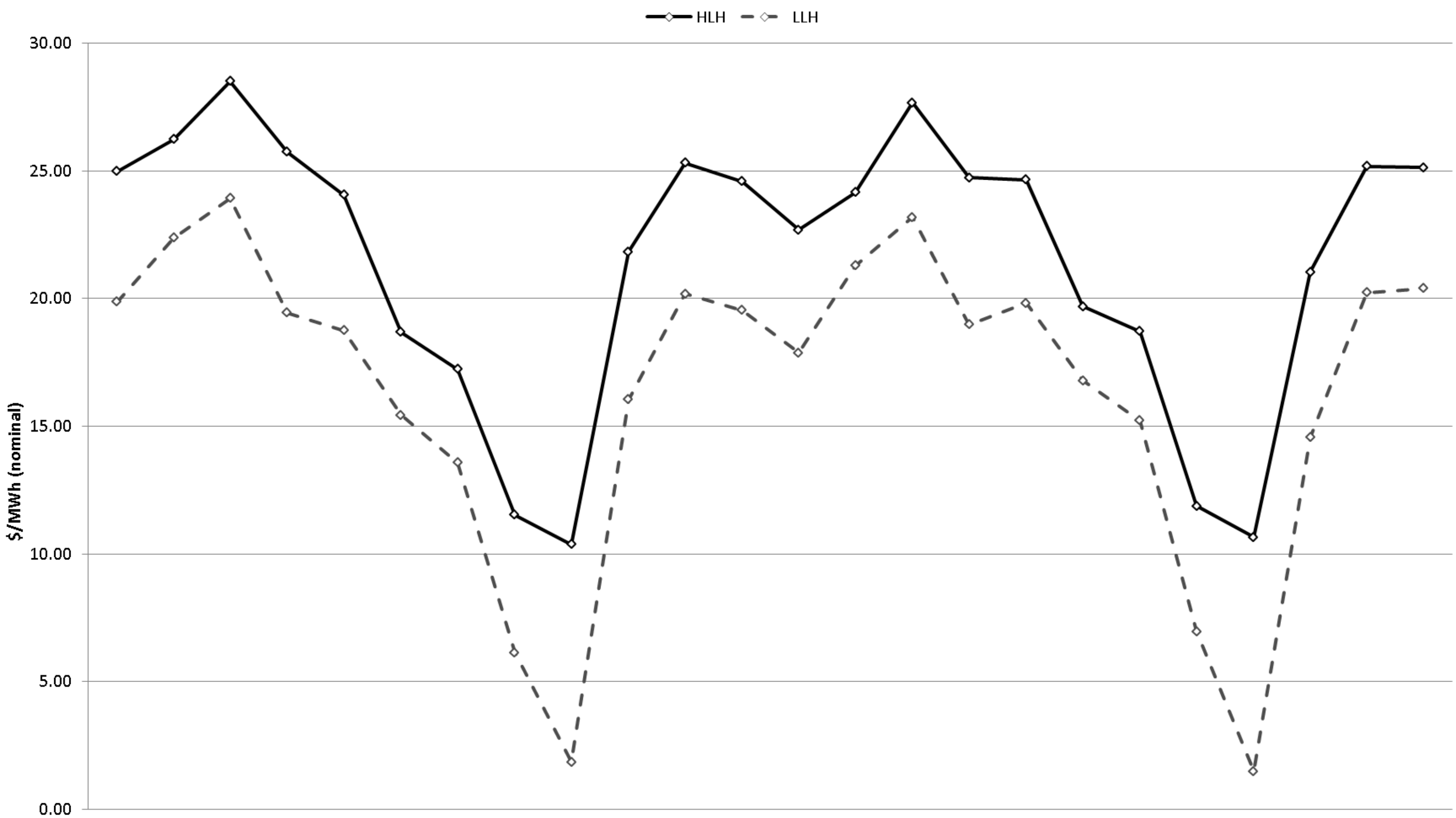
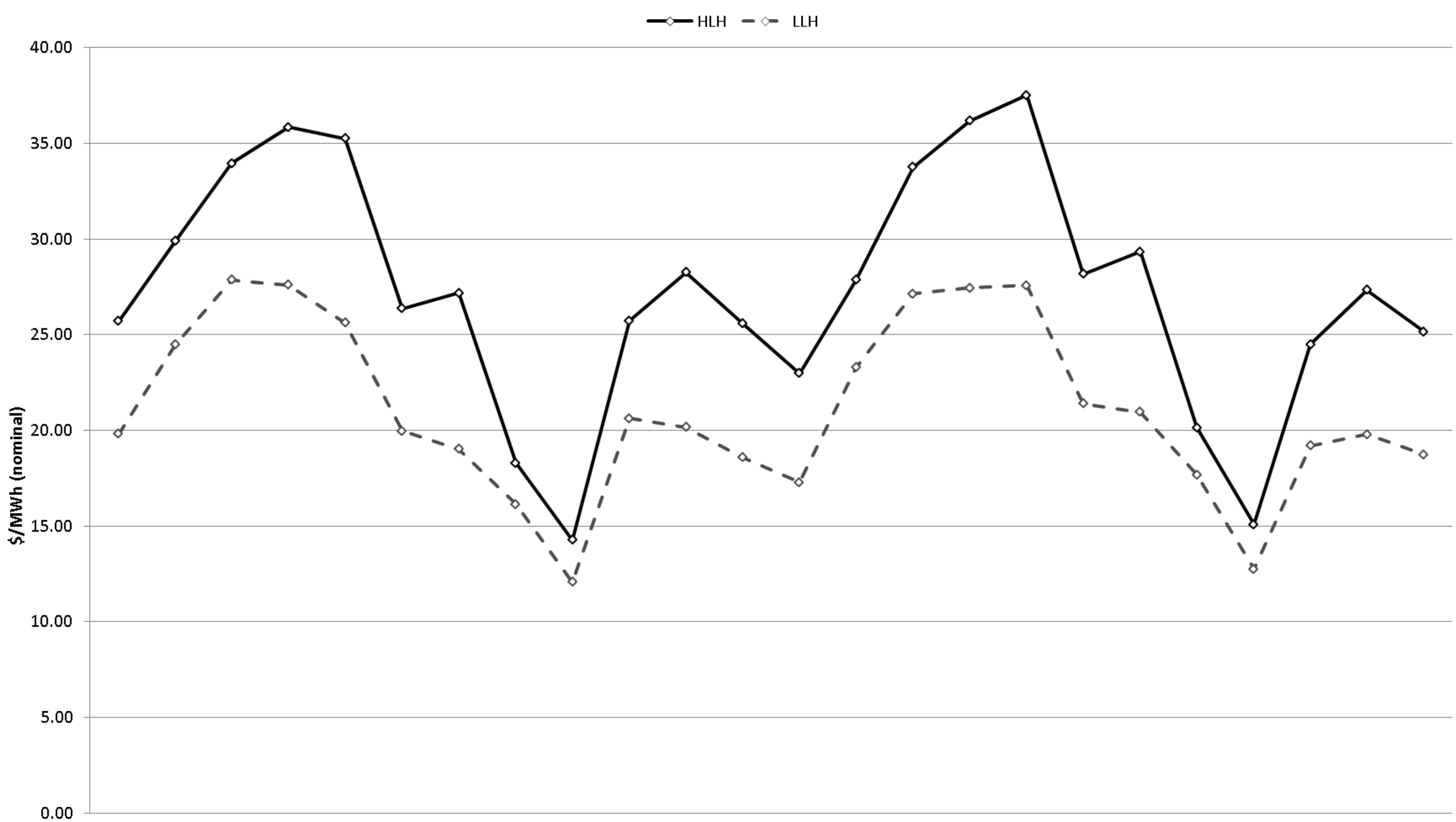


**Figure 4: Monthly Average Mid-C Market Price for FY20/FY21 80 Water Years**




| | Oct 19 | Nov 19 | Dec 19 | Jan 20 | Feb 20 | Mar 20 | Apr 20 | May 20 | Jun 20 | Jul 20 | Aug 20 | Sep 20 | Oct 20 | Nov 20 | Dec 20 | Jan 21 | Feb 21 | Mar 21 | Apr 21 | May 21 | Jun 21 | Jul 21 | Aug 21 | Sep 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | 24.98 | 26.23 | 28.51 | 25.75 | 24.06 | 18.69 | 17.24 | 11.54 | 10.38 | 21.84 | 25.31 | 24.58 | 22.69 | 24.15 | 27.67 | 24.74 | 24.65 | 19.70 | 18.72 | 11.88 | 10.65 | 21.05 | 25.18 | 25.14 |
| LLH | 19.87 | 22.39 | 23.94 | 19.44 | 18.75 | 15.43 | 13.58 | 6.15 | 1.86 | 16.05 | 20.19 | 19.55 | 17.88 | 21.30 | 23.19 | 18.98 | 19.82 | 16.79 | 15.23 | 6.96 | 1.49 | 14.57 | 20.23 | 20.40 |

**Figure 5: Monthly Average Mid-C Market Price for FY20/FY21 Critical Water**




| | Oct 19 | Nov 19 | Dec 19 | Jan 20 | Feb 20 | Mar 20 | Apr 20 | May 20 | Jun 20 | Jul 20 | Aug 20 | Sep 20 | Oct 20 | Nov 20 | Dec 20 | Jan 21 | Feb 21 | Mar 21 | Apr 21 | May 21 | Jun 21 | Jul 21 | Aug 21 | Sep 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | 25.70 | 29.88 | 33.95 | 35.84 | 35.26 | 26.37 | 27.18 | 18.30 | 14.28 | 25.73 | 28.26 | 25.58 | 22.98 | 27.85 | 33.76 | 36.18 | 37.51 | 28.16 | 29.33 | 20.14 | 15.10 | 24.51 | 27.34 | 25.16 |
| LLH | 19.82 | 24.47 | 27.86 | 27.60 | 25.63 | 19.98 | 19.02 | 16.14 | 12.07 | 20.63 | 20.16 | 18.58 | 17.28 | 23.29 | 27.14 | 27.44 | 27.58 | 21.39 | 20.97 | 17.68 | 12.75 | 19.20 | 19.80 | 18.73 |

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