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-26 Rate Proceeding

Final Proposal

Power Market Price Study

BP-26-FS-BPA-04

July 2025

POWER MARKET PRICE STUDY

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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
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
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
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission (see also "FERC")
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
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
EESC	EIM Entity Scheduling Coordinator
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
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
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)
GDP	Gross Domestic Product
GI	generation imbalance
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)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
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
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
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)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council (see also “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
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
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
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
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
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability

RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
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
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

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1. INTRODUCTION

1.1 Purpose of the Power Market Price Study

This Power Market Price Study (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-26-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-26-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[1] model (version 15.0.1006) 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, Energy Exemplar Proprietary Limited, in the database labeled North American DB 2022v9. Aurora uses a mixed integer 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. Recognizing that actual hub prices can systemically differ from a simplistic calculation of the marginal cost of electricity, BPA uses recent historical data to further calibrate the model. *See* Bid Modifiers, Section 2.3.6.1 of this Study.

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

[1] Aurora is a registered trademark of Energy Exemplar Proprietary Limited (ACN 120 461 716), the software developer.

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 iteration and serves as input to Aurora. Where applicable, that iteration 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 iteration. Because each risk model may not generate a full distribution of 2,700 iterations, where necessary the risk model is resampled to produce a full distribution. Each of the 2,700 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-26-FS-BPA-05, 2,700 independent iterations from the joint distribution of the risk models serve as the basis for the 2,700 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 (*e.g.,* 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 annual average of the monthly forecast of Henry

Hub prices is $5.38 per million British thermal units (MMBtu) for FY 2026, $4.54 per MMBtu for FY 2027, and $4.37 per MMBtu for FY 2028 *See* Table 1. (All tables and figures referenced are at the back of this document.)

2.3.1.2 Methodology for Deriving Aurora Zone Natural Gas Prices

Although Henry Hub is the point of reference for natural gas markets, Aurora uses prices for nine 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 nine 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 U.S.

Figure 1 shows the location of the nine Western hubs. The forecast of basis differentials is derived from recent historical price differentials between Henry Hub and each of the other nine 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. Stanfield, an Oregon hub, is included because major pipelines intersect at that location. 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. Ehrenberg, Arizona, represents an intermediary location between the San Juan Basin and demand centers in Southern California. Ehrenberg is also a receipt point for Permian gas, a producing area primarily located in western Texas. Inflows from the Permian area are accounted for in the formulation of the nine 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, 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, Ehrenberg, and Southern California Citygate hubs are associated with zones in Nevada, Southern California, Arizona, and New Mexico.

2.3.1.3 The Basis Price Forecasts

Adding the Henry Hub price forecast to a regional basis forecast yields that regional trading hub's price forecast. Table 1 shows the price forecast for the nine trading hubs in the Western U.S. used by Aurora. Regional supply and demand fundamentals result in some forecast prices that are significantly below the Henry Hub benchmark, such as AECO and Kingsgate, while others like SoCal Citygate and PG&E Citygate, are above.

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 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. Three simulations are produced, one around the base forecast price, one around a sustained low-price forecast, and one around a sustained high price forecast, which results in a total distribution of 1,620 simulated forecasts. This distribution is randomly sampled with weights to provide the Henry Hub natural gas price forecast input for each iteration in Aurora. The weights correspond with the estimated likelihood of each scenario occurring over the rate period.

The distribution of simulated natural gas prices is aggregated by month prior to being input into Aurora because the Treasury Payment Probability (TPP, *see* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 3.1) calculations and the Rate Analysis Model (RAM2026) (*see* Power Rates Study, BP-26-E-BPA-01, § 2.1) 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 Western Interconnection 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 U.S. BPA produces a monthly load forecast for each balancing authority (BA) in the WECC within the U.S. for the rate period. Default Aurora forecasts are used for British Columbia (BC) and Mexico, and the Alberta Electric System Operator (AESO) 2021 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 BAs, it is necessary to map the BA load forecast onto the Aurora zones. The forecast by BA is shown 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 BA level, as provided in FERC Form 714 filings from 2001 to 2022, and aggregated into the regions described above. The model de-trends 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 450 times, which generates 450 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-Columbia (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 BA'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 450 profiles of monthly deviations around the load forecast for the duration of the forecast horizon. The 450 profiles are randomly assigned to the 2,700 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 2005 to 2022. 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 eight 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 2,700 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-26-FS-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 30 year-long records of PNW monthly hydroelectric generation, based on actual water conditions in the region from 1989 through 2018 as applied to the current hydro development and operational constraints. For each of the 2,700 iterations, the model samples one of the 30 water years for the first year of the rate period (FY 2026) 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 2027 *(i.e.,* if the model uses 1989 for FY 2026, then it selects 1990 for FY 2027). Should the model sample 2018 for FY 2026, it uses 1989 for FY 2027, because 2018 is the last water year in the record. The model repeats this process for each of the 2,700 iterations and guarantees a uniform distribution over the 30 water years. The resulting 2,700 water year combinations become Aurora inputs.

2.3.3.2 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 BC. The risk model uses historical generation data from 2001 through 2021. 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 2001 through 2021 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 megawatts 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-26-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, iteration-by-iteration basis for hydro resources in the PNW.

The dispatch cost of spillable hydro generation retains the Aurora default of $1.74 per megawatthour (MWh – 2020 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 -$25/MWh (2020 real dollars), $2 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 (*i.e.,* 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 2014 to June 2023. 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

By the end of the BP-26 rate period, BPA expects more than 14,000 megawatts (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 (BAA) 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 the California Independent System Operator (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 the National Renewable Energy Laboratory's (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 exceptions of bid modifiers, and CGS generation, operation of thermal resources in Aurora is based on the Energy Exemplar-supplied database labeled North American DB 2022v9.

2.3.6.1 Bid Modifiers

Bid modifiers are tools in Aurora that allow a resource's dispatch cost (used to calculate dispatch and prices) to differ from the resource's total variable costs. Bid modifiers can have the effect of changing prices from simplistic, marginal costs of producing and delivering energy to values that better account for causal factors that are not otherwise included in BPA's implementation of Aurora. Such factors can include, but are not limited to: impacts of providing ancillary services, resource and gas pipeline outages, differences between gas hub prices and actual plant fuel costs, differences in market design, and components of scarcity pricing.

BPA uses bid modifiers to address differences between observed, historical day-ahead hub prices and simplistic marginal cost calculations generated by Aurora. Using historical values from 2018 to 2022, bid modifier values are calibrated to achieve better alignment with observed, monthly average hub prices at Mid-C, SP-15, and NP-15. BPA also considers impacts on prices averaged by hour and by month in the calibration, but the primary effect of the bid modifiers is to reduce overall bias and mean absolute error of monthly averages of day-ahead HLH and LLH hub prices over the calibration period. In general, the calibrated bid modifiers tend to increase peak hour prices, especially during winter and summer months, and put modest downward pressure on spring prices.

2.3.6.2 Columbia Generating Station Generation Risk

The CGS Generation Risk Model simulates daily 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-26-FS-BPA-03, § 3.1.4. The model employs survival analysis to estimate the number of days between outages based on historical plant data over the last 10 years. These estimates are simulated and combined with outage magnitudes and durations from the historical period. The simulated results vary from the maximum output of the plant to zero output. The frequency distribution of the 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* Power and Transmission Risk Study, BP-26-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 2,700 iterations.

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. 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 minimum constraints in a Long-Term

Capacity Expansion study that ensures a sufficient number of generic renewable resources is added to this stack to meet state renewable portfolio standards. An energy minimum 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. BPA used Aurora default overnight capital costs for new resources (wind, solar, and combined solar plus four-hour batteries) blended with our most recent consultant estimates to estimate fixed costs of new candidate resources.

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 January 2023, and various utility Integrated Resource Plans (IRPs) published between 2021 and 2023. 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.

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-26 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 solar and wind resource dispatch costs are set to -$23/MWh (2020 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 2014 through 2023. The ratings for the rest of the interconnections are based on North American DB 2022v9.

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 2014 through 2023. The data is composed of 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 three-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 2,700 iterations, 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 carbon dioxide (CO_2) emissions and requiring entities in a number of sectors, including electricity producers, to purchase sufficient allowances (shares of the total CO_2 limit) in quarterly auctions to cover their emissions. In the California electricity market, resources 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.

The California carbon market mechanisms are reflected in Aurora by applying BPA's forecast of allowance 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). BPA forecasts the following allowance prices for the BP-26 rate period: $51.02, $56.72, $62.98, and $69.62 per metric ton of CO_2 emissions (nominal) for calendar years 2025, 2026, 2027, and 2028, respectively.

Wheeling costs on transmission lines going into California are subject to an adder of the default emission rate of 0.428 metric tons per megawatthour at the forecast allowance prices. However, 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-26 rate period, all flows are exempted from the carbon emission adders on the AC and DC interties to California.

2.3.11 Washington Carbon Pricing

The Washington Climate Commitment Act (CCA) was signed into law in May 2021 and establishes carbon pricing mechanisms with many similarities to California's program. Washington's program took effect January 1, 2023.

In Aurora, an incremental carbon emission cost addition for each resource in Washington is estimated using the default CO_2 emission rates multiplied by the forecast carbon allowance price. This incremental carbon emission cost is incorporated into dispatch and commitment logic and tends to put upward pressure on forecast Mid-C prices. While the two programs are not formally linked, BPA has assumed that the Washington carbon allowance price will be equal to the California allowance price for the BP-26 rate period.

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 30 water years, and the firm water forecast uses monthly 10^{th} percentile (P10) hydro generation. Figure 4 shows the FY 2026-2028 monthly average HLH and LLH prices from the market price forecast. Figure 5 shows the FY 2026-2028 monthly average HLH and LLH prices from the firm water forecast. The BP-26 rate case average Mid-C price from the market price forecast is $38.91/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-26-E-BPA-05, and numerous components of the Power Rates Study, BP-26-FS-BPA-01.

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TABLES & FIGURES

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Table 1: Cash Prices at Henry Hub and Other Hubs (Nominal $/MMBtu)

	FY26			FY27			FY28		
Hub	**Low**	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Henry	$2.85	**$5.38**	$8.65	$2.87	**$4.54**	$8.85	$2.86	**$4.37**	$9.06
AECO	$2.41	**$4.33**	$7.79	$2.46	**$3.59**	$8.03	$2.47	**$3.37**	$8.30
Kingsgate	$2.56	**$4.79**	$8.17	$2.61	**$3.85**	$8.35	$2.62	**$3.56**	$8.59
Malin	$2.60	**$5.30**	$11.09	$2.61	**$4.37**	$11.29	$2.62	**$4.06**	$11.51
Opal	$2.80	**$5.23**	$11.06	$2.85	**$4.38**	$11.27	$2.90	**$4.14**	$11.49
PG&E	$2.75	**$6.33**	$11.36	$2.76	**$5.43**	$11.56	$2.77	**$5.17**	$11.77
SoCal City	$3.30	**$5.90**	$11.31	$3.30	**$4.97**	$11.53	$3.37	**$4.75**	$11.73
Ehrenberg	$2.91	**$5.66**	$11.14	$2.97	**$4.77**	$11.34	$3.03	**$4.53**	$11.56
Topock	$2.91	**$5.66**	$11.14	$2.97	**$4.77**	$11.34	$3.03	**$4.53**	$11.56
San Juan	$2.72	**$5.08**	$8.63	$2.73	**$4.26**	$8.84	$2.79	**$4.05**	$9.05
Stanfield	$2.63	**$5.10**	$11.03	$2.66	**$4.16**	$11.22	$2.69	**$3.86**	$11.44
Sumas	$2.79	**$5.13**	$11.02	$2.88	**$4.19**	$11.22	$2.89	**$3.97**	$11.45

Table 2: Balancing Area Load Forecast

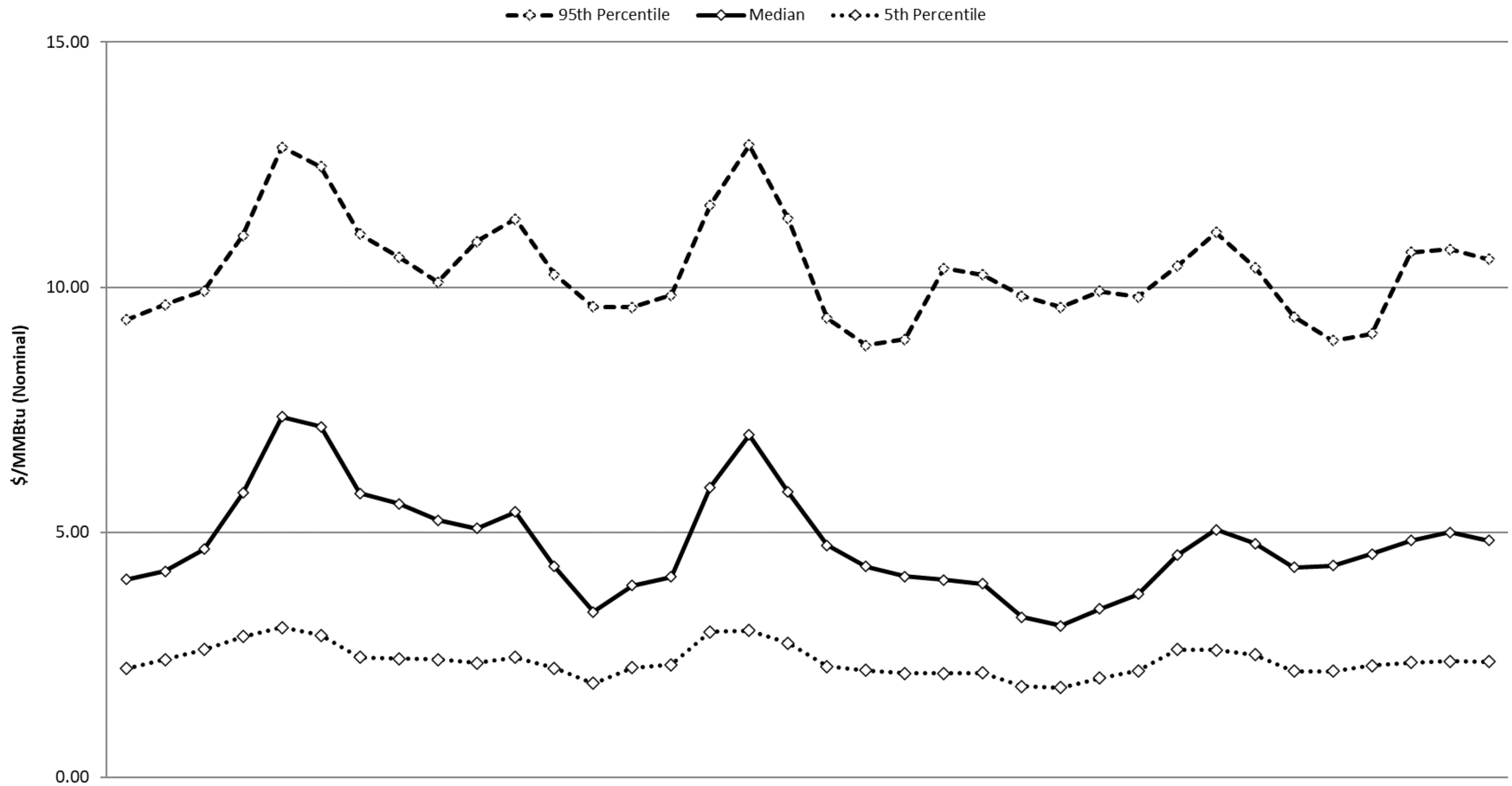
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 2: Balance Area Load Forecast (MWh)**														
2	**Date**	**APS**	**AVA**	**BPA**	**CHPD**	**CISO**	**DOPD**	**EPE**	**GCPD**	**IID**	**IPC**	**LDWP**	**NEVP**	**NWE**	**PAC**
3	**Oct-25**	2400740	1020683	4984703	143472	18840830	157759	709600	508787	313277	1305095	2060103	1872729	986899	6028345
4	**Nov-25**	2074600	1082955	5233206	184878	17297437	184336	653152	498643	249735	1324753	1905808	1714573	1001441	6104373
5	**Dec-25**	2270739	1301747	6271245	254353	18295904	237817	726371	551338	232896	1641366	2008736	1906302	1142737	6828517
6	**Jan-26**	2301537	1294374	6280991	234287	17956339	242045	730011	562162	245586	1619223	2091980	1887677	1146463	6891470
7	**Feb-26**	2037847	1091505	5245111	193127	15807673	188886	638835	493979	220881	1378641	1905457	1652285	992639	6079813
8	**Mar-26**	2102842	1108923	5479071	173986	17180590	173002	660453	496243	249655	1348072	2005461	1743636	1022565	6264992
9	**Apr-26**	2158363	1006631	5082699	130988	16600266	154157	661275	506634	289186	1335185	1873662	1709465	958613	5865132
10	**May-26**	2591637	971544	4981823	127833	18012791	157955	738953	540777	352012	1531736	2031773	2170234	951382	5915067
11	**Jun-26**	3028830	990884	5021761	132951	20017500	164016	832721	577090	446249	1859151	2173116	2696077	990334	6384153
12	**Jul-26**	3660953	1105737	5327830	155562	23001901	191237	932629	623166	539100	2176934	2816199	3140799	1112433	7250195
13	**Aug-26**	3638593	1076884	5203019	146559	23641230	182861	929250	597490	537722	1989159	2774845	3084721	1080179	6983244
14	**Sep-26**	3025556	939705	4653728	128664	20949790	159523	794657	518922	411562	1480704	2333479	2463971	958139	6048411
15	**Oct-26**	2419888	1025028	5142481	145917	19223480	160605	715842	519272	317495	1320343	2064404	1883654	1000349	6103001
16	**Nov-26**	2093710	1087349	5386872	187981	17661381	187251	659222	509019	253286	1340001	1910713	1725221	1014986	6178935
17	**Dec-26**	2289811	1306181	6429195	258474	18671373	240786	732446	561585	236102	1656818	2014047	1917092	1156379	6902695
18	**Jan-27**	2340125	1300288	6447280	238354	18379197	245324	736770	573189	249689	1636631	2113584	1901431	1160384	6975616
19	**Feb-27**	2076363	1097236	5397864	196593	16204227	192071	645610	505044	224923	1396082	1927537	1665897	1006731	6164469
20	**Mar-27**	2141103	1114688	5645209	177092	17594568	176102	667207	507337	253993	1365389	2027825	1757375	1036815	6349601
21	**Apr-27**	2196536	1012328	5245745	133403	17007248	157260	668165	518104	294344	1352788	1895202	1723430	973041	5949858
22	**May-27**	2629429	977004	5149299	130207	18435690	161110	745986	552574	357935	1549886	2054372	2185260	965978	5999862
23	**Jun-27**	3066553	996151	5184489	135404	20463927	167203	839781	589059	453234	1878008	2195911	2712047	1005061	6469389
24	**Jul-27**	3699629	1111185	5494541	158392	23481907	194518	939606	635331	546769	2195996	2844682	3157042	1127246	7335781
25	**Aug-27**	3677354	1082371	5369538	149234	24130455	186130	936236	609750	545293	2008048	2802812	3100873	1094993	7068576
26	**Sep-27**	3063639	945237	4816258	131080	21408904	162768	801578	531257	417900	1499097	2359157	2479653	972965	6133771
27	**Oct-27**	2458452	1030825	5294969	148483	19688372	163773	722591	531518	322739	1338065	2088813	1898165	1015129	6188304
28	**Nov-27**	2132208	1093233	5535478	191227	18105261	190504	665730	521221	257754	1357688	1935117	1739290	1029677	6264036
29	**Dec-27**	2328236	1312141	6581508	262735	19128084	244127	738911	573787	240136	1674739	2039248	1931281	1170981	6987205
30	**Jan-28**	2368552	1307899	6608824	242585	18888868	249014	743940	586403	254304	1656682	2146586	1918841	1177736	7071047
31	**Feb-28**	2160869	1138032	5701827	207225	17240685	196401	655637	501957	235600	1449558	2030126	1727377	1017181	6377066
32	**Mar-28**	2169075	1122154	5806359	180349	18094333	179555	674292	520919	258886	1385262	2061638	1774624	1054165	6445469
33	**Apr-28**	2224381	1019727	5404358	135949	17499170	160725	675408	532356	300144	1372992	1928024	1740897	990408	6045803
34	**May-28**	2656692	984106	5311670	132712	18945293	164636	753377	567334	364494	1570749	2088139	2204021	983352	6095801
35	**Jun-28**	3093725	1003041	5342310	137994	20999836	170749	847173	604178	460831	1899701	2229546	2731951	1022390	6565812
36	**Jul-28**	3728016	1118294	5655636	161367	24055081	198199	946910	650743	554918	2217893	2884271	3177256	1144560	7432565
37	**Aug-28**	3705848	1089496	5530273	152050	24714203	189772	943621	625261	553303	2029641	2841381	3120948	1112267	7164973
38	**Sep-28**	3091255	952377	4973394	133639	21959246	166382	808940	546846	424736	1519977	2395076	2499097	990209	6230139

Table 2: Balancing Area Load Forecast (cont.)

39	Table 2 (cont): Balance Area Load Forecast (MWh)														
40	**Date**	**PGE**	**PNM**	**PSC**	**PSE**	**SCL**	**SMUD**	**SPP**	**SRP**	**TEP**	**TID**	**TPWR**	**WACM**	**WALC**	**WAUW**
41	**Oct-25**	1711188	822049	4076117	2143485	743127	1331623	1192089	2538974	1214376	243119	399084	1520071	797769	68762
42	**Nov-25**	1776595	828996	4151641	2337490	829919	1283150	1204448	2144773	1117053	218383	417532	1646278	677656	77148
43	**Dec-25**	2110503	934015	4618043	2839058	960324	1457713	1317013	2395834	1224058	225522	499929	1864886	712171	92682
44	**Jan-26**	2095007	933660	4624896	2570000	961457	1469976	1303406	2375660	1239484	222915	503294	1909796	678303	95938
45	**Feb-26**	1722978	824621	4193526	2490083	844280	1260839	1188723	2106232	1095909	202890	443451	1699610	644201	86163
46	**Mar-26**	1826393	849933	4267287	2444692	861779	1321725	1238818	2208111	1136789	214694	449847	1776044	754741	80074
47	**Apr-26**	1681505	785031	3994779	2018275	754058	1260287	1170600	2307861	1117846	216196	394749	1651393	856163	70487
48	**May-26**	1671868	821499	4087476	1915194	699096	1415730	1208727	2981202	1264819	250665	363741	1515442	985828	67865
49	**Jun-26**	1652310	924218	4415463	2047005	655146	1680060	1243506	3639091	1559754	303389	346451	1641384	911626	83047
50	**Jul-26**	1817307	1054841	5111793	2010929	692571	1923195	1381276	4094741	1670350	346924	364747	1987961	969337	101575
51	**Aug-26**	1874979	1022963	4801129	2036656	693260	1921910	1391841	4006954	1684351	334933	367122	1882273	945037	90811
52	**Sep-26**	1660097	878635	4104797	1899535	672652	1610839	1230942	3497470	1479514	280224	344601	1576389	934194	70935
53	**Oct-26**	1729833	839114	4141888	2190772	743201	1351007	1212037	2575758	1222914	245940	400146	1527321	803330	69113
54	**Nov-26**	1795352	846351	4217170	2388478	834748	1302696	1224705	2181266	1125934	221057	418498	1653940	682944	77532
55	**Dec-26**	2129456	951633	4683492	2899287	961899	1478850	1337163	2432495	1232915	228154	500621	1872664	717298	93085
56	**Jan-27**	2116626	954919	4698386	2627510	964827	1497048	1325589	2416591	1250622	226295	504877	1920398	684691	96496
57	**Feb-27**	1744371	845082	4267164	2547278	848784	1286035	1211083	2147120	1106959	206253	445021	1710109	650981	86740
58	**Mar-27**	1847969	870426	4340782	2500637	868325	1346671	1261072	2248972	1147741	218032	451395	1786737	762177	80595
59	**Apr-27**	1703046	806080	4068342	2065612	757967	1284531	1192650	2348910	1128392	219631	396277	1661997	864504	70977
60	**May-27**	1693431	842601	4161663	1960386	703230	1441266	1229788	3050064	1274732	254394	365161	1525125	994137	68343
61	**Jun-27**	1673576	945686	4489634	2095078	657706	1708123	1263710	3708526	1570047	307563	347740	1651086	918479	83604
62	**Jul-27**	1838594	1076539	5185671	2057613	694859	1952405	1401247	4163890	1680193	351212	366030	1998126	975749	102182
63	**Aug-27**	1896656	1044609	4874918	2084067	699679	1950750	1411919	4075920	1694341	338992	368425	1892414	951322	91372
64	**Sep-27**	1681819	900098	4178680	1944770	675367	1636992	1251472	3566622	1489581	283912	345934	1586285	941238	71433
65	**Oct-27**	1751550	860740	4215948	2240544	745091	1374313	1233707	2617072	1233442	249373	401518	1536946	810511	69580
66	**Nov-27**	1817132	868228	4290834	2441972	841234	1326370	1246836	2222171	1136913	224310	419767	1664114	689758	78043
67	**Dec-27**	2151416	973690	4756973	2961964	966281	1504644	1359191	2473623	1243886	231353	501754	1883000	723903	93623
68	**Jan-28**	2141432	980893	4780725	2687656	972750	1525537	1349935	2462740	1264282	229633	506717	1933863	692689	97205
69	**Feb-28**	1833502	881710	4365791	2698594	885714	1356528	1237150	2229172	1145625	216717	460734	1801121	681200	90577
70	**Mar-28**	1872562	896208	4422988	2559477	872948	1373165	1285599	2295029	1161183	221348	453284	1800306	771516	81255
71	**Apr-28**	1727511	830703	4150573	2115682	760069	1310447	1216962	2395194	1141318	223071	398170	1675454	875005	71599
72	**May-28**	1717842	867903	4244612	2008196	712953	1468440	1252876	3124650	1286808	258094	366968	1537411	1004564	68948
73	**Jun-28**	1697535	971298	4572484	2145916	661583	1737774	1285739	3783790	1582626	311651	349383	1663405	927051	84311
74	**Jul-28**	1862562	1102306	5268053	2106850	700075	1982794	1422991	4238748	1692193	355312	367674	2011050	983760	102954
75	**Aug-28**	1921160	1070245	4957087	2134110	706205	1980684	1433792	4150543	1706520	342875	370107	1905302	959170	92086
76	**Sep-28**	1706421	925472	4260878	1992749	679709	1664553	1273922	3641531	1501853	287540	347665	1598849	950053	72065

Figure 1: Natural Gas Trading Hubs

Figure 2: Natural Gas Price Risk Model Henry Hub Percentiles (Nominal $/MMBtu)



	Oct 25	Nov 25	Dec 25	Jan 26	Feb 26	Mar 26	Apr 26	May 26	Jun 26	Jul 26	Aug 26	Sep 26
95th Percentile	9.33	9.64	9.92	11.0	12.8	12.4	11.0	10.6	10.1	10.9	11.3	10.2
Median	4.04	4.20	4.66	5.80	7.35	7.15	5.79	5.58	5.25	5.08	5.41	4.30
5th Percentile	2.22	2.40	2.60	2.87	3.05	2.90	2.45	2.41	2.40	2.33	2.44	2.22

	Oct 26	Nov 26	Dec 26	Jan 27	Feb 27	Mar 27	Apr 27	May 27	Jun 27	Jul 27	Aug 27	Sep 27
95th Percentile	9.60	9.59	9.84	11.6	12.9	11.4	9.37	8.81	8.94	10.3	10.2	9.82
Median	3.38	3.91	4.09	5.92	6.98	5.82	4.73	4.30	4.10	4.02	3.94	3.27
5th Percentile	1.91	2.24	2.30	2.97	3.00	2.74	2.26	2.18	2.12	2.12	2.13	1.86

	Oct 27	Nov 27	Dec 27	Jan 28	Feb 28	Mar 28	Apr 28	May 28	Jun 28	Jul 28	Aug 28	Sep 28
95th Percentile	9.59	9.92	9.80	10.4	11.1	10.4	9.40	8.91	9.05	10.7	10.7	10.5
Median	3.09	3.43	3.74	4.53	5.05	4.76	4.28	4.31	4.56	4.83	5.00	4.83
5th Percentile	1.83	2.03	2.17	2.60	2.59	2.50	2.16	2.17	2.28	2.34	2.37	2.36

Figure 3: Aurora Zonal Topology

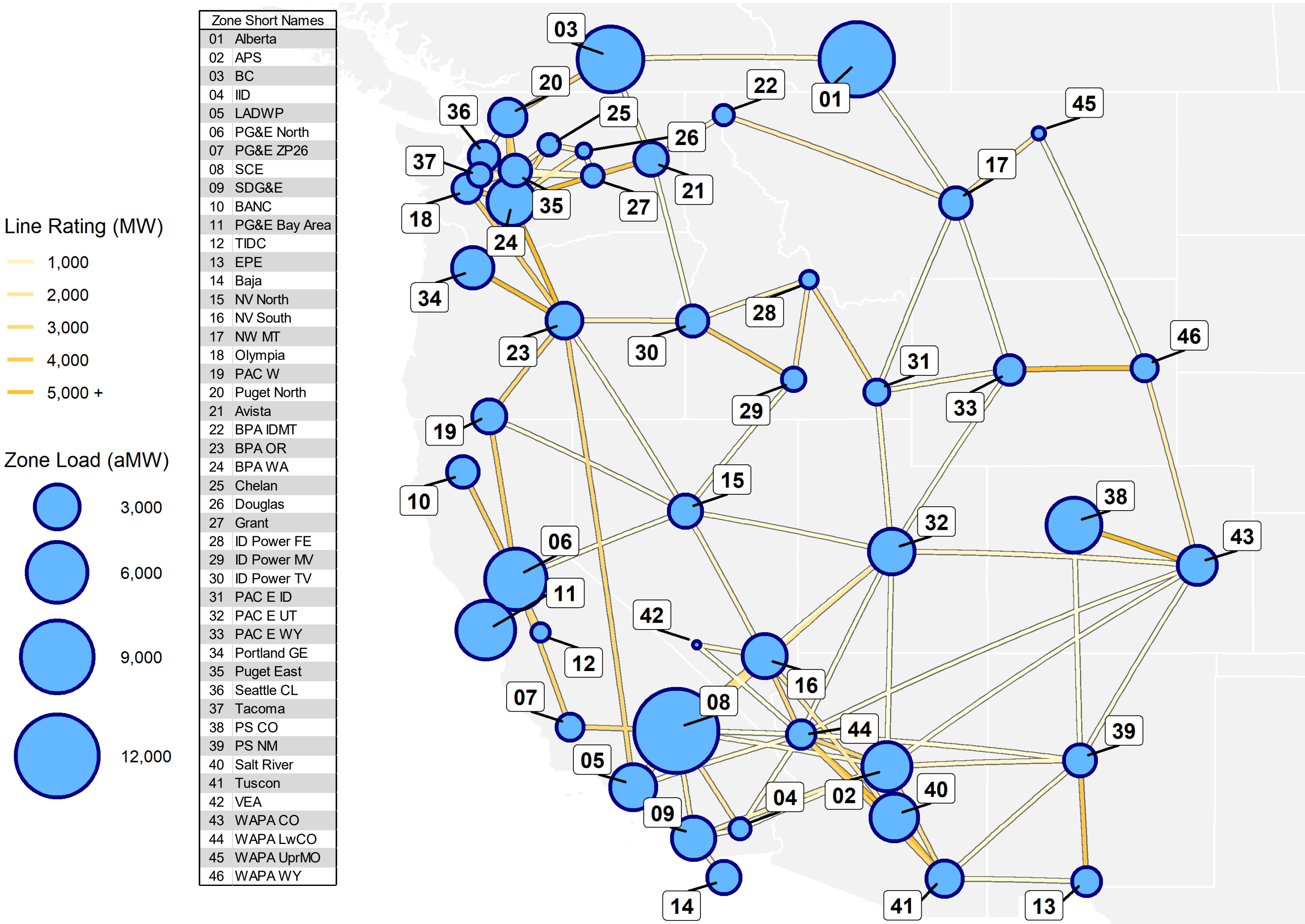
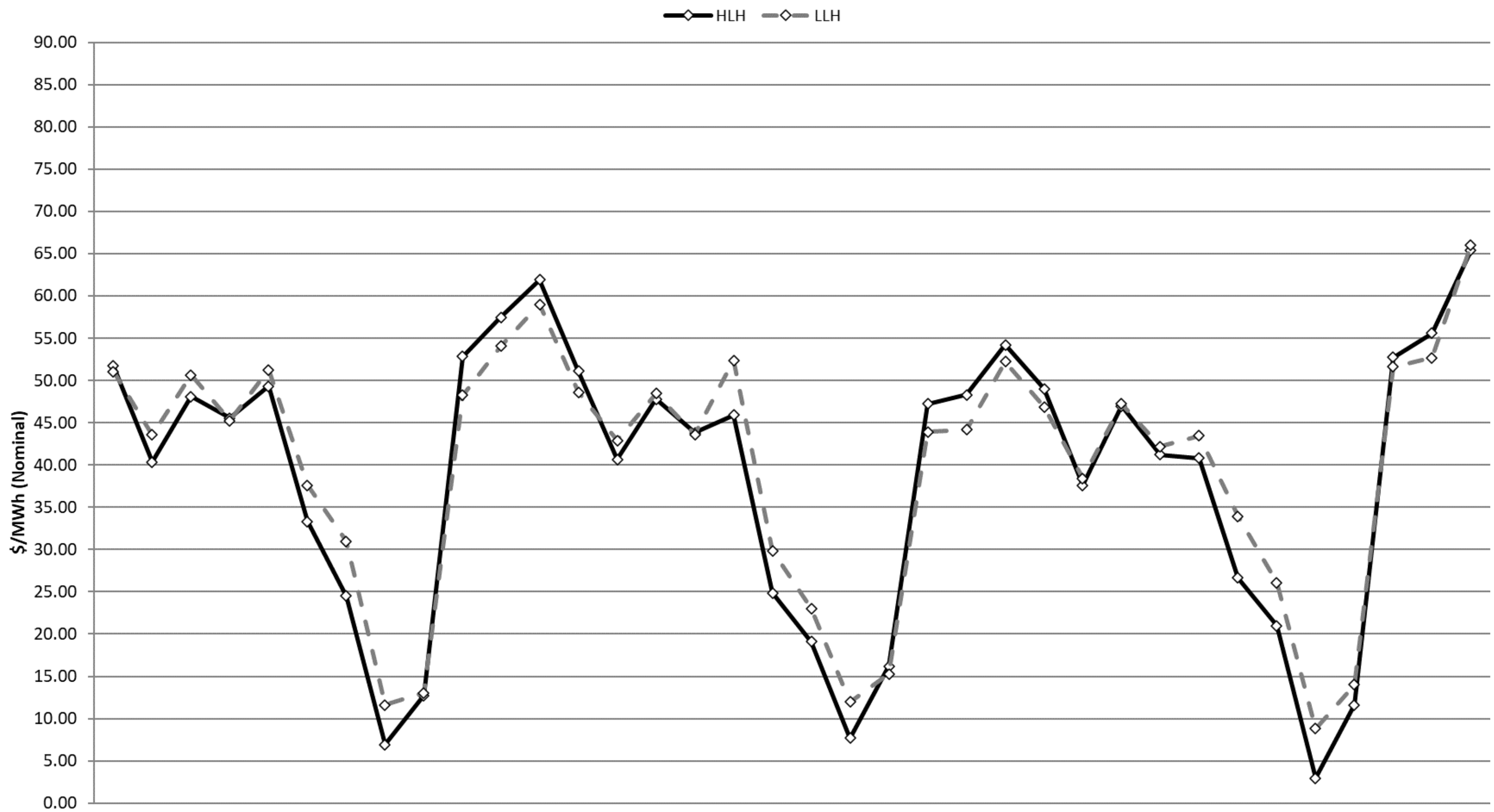


Figure 4: Monthly Average Mid-C Market Price for FY26 - FY28 30 Water Years

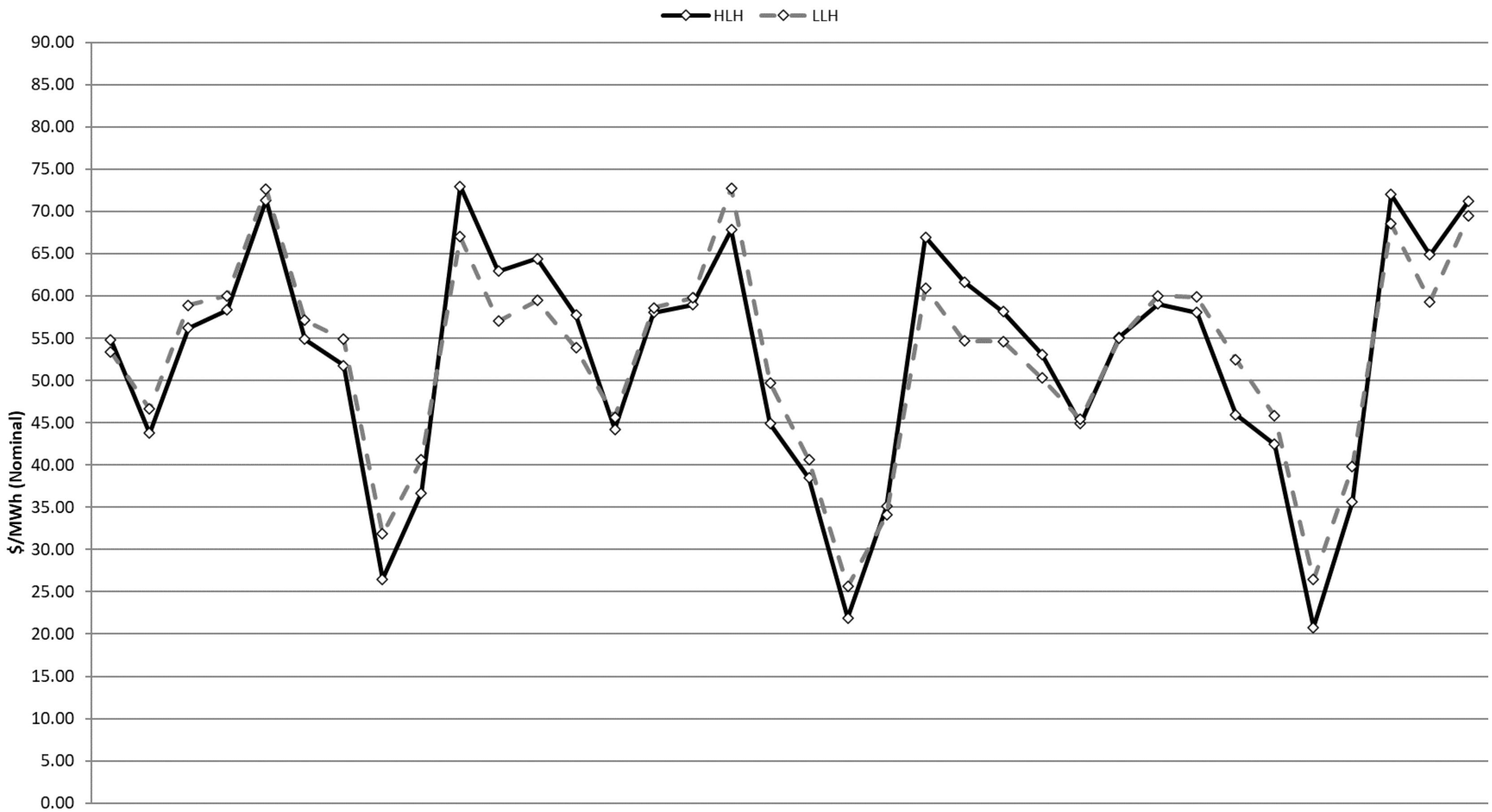


	Oct 25	Nov 25	Dec 25	Jan 26	Feb 26	Mar 26	Apr 26	May 26	Jun 26	Jul 26	Aug 26	Sep 26
HLH	51.7	40.3	48.0	45.5	49.3	33.3	24.5	6.92	12.7	52.8	57.4	61.9
LLH	51.0	43.5	50.6	45.2	51.2	37.6	31.0	11.6	13.0	48.2	54.0	58.9

	Oct 26	Nov 26	Dec 26	Jan 27	Feb 27	Mar 27	Apr 27	May 27	Jun 27	Jul 27	Aug 27	Sep 27
HLH	51.1	40.6	47.8	43.8	45.9	24.8	19.1	7.69	16.2	47.2	48.3	54.2
LLH	48.6	42.9	48.4	43.6	52.4	29.8	23.0	11.9	15.2	43.9	44.2	52.2

	Oct 27	Nov 27	Dec 27	Jan 28	Feb 28	Mar 28	Apr 28	May 28	Jun 28	Jul 28	Aug 28	Sep 28
HLH	49.0	37.5	46.9	41.2	40.7	26.6	21.0	2.94	11.6	52.7	55.6	65.3
LLH	46.8	38.4	47.2	42.1	43.4	33.9	26.1	8.81	14.0	51.6	52.7	65.9

Figure 5: Monthly Average Mid-C Market Price for FY26 - FY28 Firm Water



	Oct 25	Nov 25	Dec 25	Jan 26	Feb 26	Mar 26	Apr 26	May 26	Jun 26	Jul 26	Aug 26	Sep 26	Oct 26	Nov 26	Dec 26	Jan 27	Feb 27	Mar 27	Apr 27	May 27	Jun 27	Jul 27	Aug 27	Sep 27	Oct 27	Nov 27	Dec 27	Jan 28	Feb 28	Mar 28	Apr 28	May 28	Jun 28	Jul 28	Aug 28	Sep 28
HLH	54.8	43.7	56.2	58.3	71.3	54.9	51.7	26.4	36.6	72.9	62.9	64.4	57.7	44.2	58.0	58.9	67.8	44.9	38.4	21.8	35.1	66.9	61.6	58.1	53.1	44.8	55.1	59.0	58.0	45.9	42.4	20.7	35.6	71.9	64.8	71.2
LLH	53.4	46.6	58.8	60.0	72.6	57.1	54.9	31.8	40.6	67.0	57.0	59.4	53.8	45.6	58.6	59.7	72.7	49.7	40.6	25.6	34.1	60.9	54.6	54.6	50.3	45.4	54.9	60.0	59.8	52.4	45.8	26.4	39.7	68.5	59.2	69.4

Bonneville Power Administration
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