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-18 Rate Proceeding

Final Proposal

# Power Market Price Study and Documentation

BP-18-FS-BPA-04

July 2017

**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 |
| 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 |
| FOIA | Freedom Of Information Act |
| FORS | Forced Outage Reserve Service |
| FPS | Firm Power and Surplus Products and Services |
| FPT | Formula Power Transmission |
| 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 |
| LPTAC | Large Project Targeted Adjustment Charge |
| LTF | Long-term Form |
| 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 |
| 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 |
| Peak | Peak Reliability (assessment/charge) |
| 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 |
| Project Act | Bonneville Project Act |
| 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 |
| REC | Renewable Energy Certificate |
| Reclamation | U.S. Bureau of Reclamation |
| RDC | Reserves Distribution Clause |
| 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 rate |
| 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 |

| | |
|---|---|
| VERBS | Variable Energy Resources 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 in BPA's ratemaking. This Study includes BPA's natural gas price forecast and electricity market price forecast. In previous rate proposals the Power Market Price Study and the Power Risk Study were included in the same document (*e.g.,* BP-16-FS-BPA-04). For BP-18 the Market Price Study is separate, and the Power and Transmission risk studies are included in the same document, BP-18-FS-BPA-05.

## 1.2 How Market Price Results Are Used

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-18-FS-BPA-05. The Risk Study applies this distribution of future price expectations to BPA's net position to quantify risk surrounding rate levels to reflect the uncertainty in cost recovery inherent in the volatility of market price fundamentals.

Forecasts of electricity market prices are used in the Power Rates Study, BP-18-FS-BPA-01, in the calculations of:

- Prices for secondary energy sales and balancing power purchases
- Prices for augmentation purchases

- 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 AURORAxmp®

BPA uses the AURORAxmp® (version 12.1.1043) 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 Inc., in the database labeled North American DB 2016v5. AURORAxmp® 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) Hourly Wind Generation
- Columbia Generating Station (CGS) Generation
- PNW Hourly Intertie Availability

Each statistical model calibrates to historical data and employs Monte Carlo simulation to generate a distribution of future outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to AURORAxmp®. Where applicable, that game also serves as input to BPA's Revenue Simulation model (RevSim). The prices from AURORAxmp®, combined with the generation and expenses from RevSim, constitute one net revenue game. Each risk model may not generate 3,200 games, and where necessary a bootstrap is used to produce a full distribution of 3,200 games. 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 AURORAxmp® prices and RevSim inventory levels.

## 2.2 R Statistical Software

The risk models used in AURORAxmp® 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), an operating system that is 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 AURORAxmp® are generated in a unified environment.

## 2.3 AURORAxmp® Model Inputs

AURORAxmp® produces a single electricity price forecast as a function of its inputs. Thus, producing a given number of price forecasts requires that AURORAxmp® be run that same number of times using different inputs. Risk models provide inputs to AURORAxmp®, 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-18-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 AURORAxmp® is an hourly model, the monthly prices in AURORAxmp® 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 AURORAxmp®.

### 2.3.1 Natural Gas Prices Used in AURORAxmp®

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 available generator 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, rising natural gas prices will typically translate into an increase 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, 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 Methodology for Deriving AURORAxmp® Zone Natural Gas Prices

Each natural gas plant modeled in AURORAxmp® operates using fuel priced at a natural gas hub according to the zone in which it is located. Each zone is a geographic subset of the WECC.

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

Though Henry Hub is the point of reference for natural gas markets, AURORAxmp® uses prices for 11 gas trading hubs in the WECC. The prices at hubs other than Henry 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. Sumas, Washington, is the primary hub for the delivery of gas from the Western Canada Sedimentary Basin (WCSB) into western Washington and western Oregon. The Opal, Wyoming, hub represents the collection of Rocky Mountain supply basins that supply gas to the Pacific Northwest and California. The San Juan Basin has its own hub, which primarily delivers gas to southern California. AECO, the primary trading hub in Alberta, Canada, is the main benchmark for Canadian gas prices. Kingsgate is another gateway for WCSB gas and is the hub that is associated with the demand center in Spokane, Washington. Two eastern Oregon hub locations, Stanfield and Malin, are included because major pipelines intersect at those locations. Pacific Gas and Electric (PG&E) Citygate represents demand centers in northern California. Topock, Arizona, and Ehrenberg, Arizona, represent intermediary locations between the San Juan Basin and demand centers in Southern California. With respect to the basis differential forecast, the same price is used for both of these Arizona hubs, as they serve largely the same purpose and share the same underlying fundamentals. Finally, Southern California Citygate represents demand centers in southern California.

Once a forecast is prepared for the trading hubs' basis values, AURORAxmp® 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.

**2.3.1.2 Recent Natural Gas Market Fundamentals**

Gas prices have varied substantially over time and most recently have been at the low end of recent historical values. *See* Figure 2. U.S. natural gas production for 2016 declined relative to 2015, on an annual basis. The expectation is that 2017 annual average production will be roughly equal to the 2016 annual production level, but the trajectory of production across the year is expected to be different in 2017: production declined throughout 2016, but is expected to increase throughout 2017. Throughout 2015 and 2016, the marginal cost of natural gas production continued to drop because advances in technology improved the efficiency of production in all phases, including exploration, drilling, and well stimulation. Producers are focusing on the most easily attainable resources by drilling longer, better targeted, lateral wells to increase rig efficiencies and decrease costs.

In 2016 the market reached sufficiently low prices and rig count levels such that, despite efficiency gains, production significantly declined; 2016 averaged about 1.67 billion cubic feet per day [Bcf/d] less than 2015. *See* Figure 3. Now production needs to increase again in order to match demand. The turnaround in 2017 is expected to be fueled by two main sources of gas: associated gas—a byproduct of oil production in certain oil plays (a play being a defined geographic location where natural gas can be recovered from the underlying geology) that has virtually no cost—and Appalachian shale gas, which is recoverable at very low cost. Therefore, fundamental cost drivers on the supply side remain low.

The winter of 2013–2014 created record demand due to cold weather and lagging supply that led to a record pace of storage withdrawals and the highest prices in the shale gas era. The supply response was swift and strong. Production powered through a colder than normal winter in 2014–2015, and storage entered the 2015–2016 withdrawal season at the all-time record high level of 4,009 Bcf of natural gas. Storage proceeded to exit the withdrawal season at another all-time record high of 2,473 Bcf, setting the stage for low prices and attempts at producer restraint in 2016. *See* Figure 4.

In 2016 the market rebalanced, and is now even considered short by many market experts. Average daily production is expected to be less than average daily demand in 2017. This should result in both the increasing price of natural gas and increasing rig counts. It is expected that through the remainder of FY 2017, and through FY 2018, production will rise to match demand, and they will then stay roughly in balance leaving natural gas prices relatively stable. As the rate period progresses into FY 2019, supply should slowly surpass demand, leading to slightly lower prices in FY 2019 than in FY 2018.

**2.3.1.3 Henry Hub Forecast**

The average of the monthly forecast of Henry Hub prices is $3.12 per million British thermal units (MMBtu) during FY 2018 and $3.00/MMBtu during FY 2019. *See* Table 1.

Depending on the makeup of supply—from associated gas to dry gas and wet gas—gas prices should eventually settle out at the long-run marginal cost of natural gas production. It is estimated that, assuming normal weather, supply will continue to lag demand in FY 2017 and balance should be reached by, or in, FY 2018. However, it is expected that supply will again exceed demand in FY 2019. Given marginal production cost estimates in the industry today and assuming that the market can remain close to equilibrium long-run marginal cost, prices in the FY 2018–2019 rate period are expected to average in the high $2.00/MMBtu to low $3.00/MMBtu range.

There are many supply-side pressures keeping gas price expectations from rising above this level. In the current natural gas market, low-cost and highly productive plays are expanding production to meet additional calls on natural gas supply, and the expansion of this low-cost resource base is displacing higher-cost marginal resources. By bringing more very low-cost resources into the supply mix, the price expectation at almost all levels of production is adjusted downward in the forecast.

The Marcellus and Utica gas plays, located in the Appalachian region of the United States, have become a dominant story in the natural gas landscape. They have low breakeven costs, they have shown that they can ramp up production levels quickly, and they are located close to premium Northeast U.S. (NE) markets. Given their historical performance, it is reasonable to expect that these plays will be able to increase production quickly and inexpensively in the future to meet incremental calls from demand. The major barrier for these NE plays is take-away pipeline capacity. While there is ample capacity scheduled to come online through 2019, there is always the potential for unforeseen delays and cancellations to hamper the ability of NE gas to expand production and seize market share.

On the other side of the continent, WCSB gas has also shown itself to be resilient to the low-price environment. With a large amount of natural gas produced almost as a byproduct from extracting natural gas liquids (condensate) for Canadian oil-sand processing and transport, this persistent and cheap supply has pushed down into the Pacific Northwest and east into the Rockies as well as down from Canada into the Midwestern United States.

Associated gas out of the Permian, located in west Texas and southeast New Mexico, has arisen as an unexpectedly large source of incremental natural gas production. The Permian is primarily an oil play and returns on investment are quite large, given current oil prices. Producers have responded by adding rigs to the region to the point that market experts are expecting associated gas volumes to soon exceed the already large capacity of existing takeaway pipeline infrastructure.

Growth in gas produced in the Marcellus and Utica plays, the WCSB, and in association with oil extraction in the U.S. is expected to prove sufficient to maintain the low prices the markets have come to expect from the U.S. shale gas era. Production and supply are expected to remain strong and capable of meeting incremental demand without significant price increases through the BP-18 rate period.

Although these supply-side pressures are significant, when forecasting Henry Hub prices it is important to consider demand as well. In response to low prices, the FY 2017–2019 timeframe shows the potential for significant long-term demand growth in liquefied natural gas (LNG) exports, Mexican exports, and the industrial sector. Sources of demand such as gas burn for power generation and LNG spot market transactions should function as the primary demand-side levers for making short-term adjustments to balance the market. If demand growth outpaces supply growth, storage levels will decrease and Henry Hub prices will likely increase to the point that natural gas-fired generation will become less cost-effective and be priced out of the market in favor of less expensive coal generation, thereby reducing demand. Conversely, if supply growth outpaces demand, natural gas prices will fall to lower the costs of natural gas-fired generation, pricing it into the market and raising demand. LNG export capacity not secured in long-term contracts should serve a similar function as export capacity is priced in and out of the global natural gas market.

Looking forward, exports are expected to make up an increasingly significant portion of overall natural gas demand. For LNG exports from the U.S., 2016 was a big year. The Sabine Pass LNG terminal sent out its first cargo in February and provided up to 1.3 Bcf/d of incremental demand (once Train 2 ramped up). Through 2019, LNG exports could grow to total 3 Bcf/d, or more.

The Mexican natural gas extraction industry is currently reforming to a more deregulated environment, with the specified aim of opening up the industry to the private sector. Into the foreseeable future the U.S. is likely to provide significant amounts of gas to the Mexican marketplace. About 1 Bcf/d or more of incremental exports are expected through FY 2019.

Another category of major demand growth is industrial sector demand. To date, industrial demand has been slow to recover from the recession. However, recent low natural gas prices have inspired growth in industries using natural gas or its byproducts as feedstock. A lag between a price change and induced demand is generally expected in the industrial component of natural gas demand, because investment decisions require implementation time. Due to this lag, the industrial sector was not able to provide any meaningful price support in the FY 2015 and

FY 2016 period. It is expected that investment decisions will begin to induce industrial demand growth during the BP-18 rate period, with projections ranging between 1 and 2 Bcf/d of growth through FY 2019.

Natural gas demand for power burn reached record levels in 2016, helping to absorb excess gas supply. Where possible, to maximize efficiencies and take advantage of low natural gas fuel costs, coal generating units were shut down and gas generating units fired up in their place. As natural gas prices rise through FY 2017 and FY 2018, and the costs of operating natural gas plants also rise, some coal units will work their way back into the generating stack, reducing natural gas demand for power burn. However, coal and nuclear retirements through the duration of the rate period will continue to provide the opportunity to maintain or increase natural gas baseload demand. Because gas demand for power burn has been at such elevated levels, and rising gas prices and increasing renewable energy penetration (which lower gas demand) can oppose the effect of retirements of competing fuel generating resources (coal and nuclear power plants), industry opinion is split on whether gas demand for power burn will increase or decrease through the rate period. Demand at its existing levels can be assumed to support Henry Hub prices.

Demand growth from these categories, combined with other organic growth, should prove sufficient to balance the market through the first year of the rate period (FY 2018). However, balance depends on both sides of the supply and demand equation. Risks to the forecast balance are risks to expected prices. Unexpected activities or shocks to either side could send prices higher or lower than the forecast. General sources of risk are weather, legislative action that restricts (or promotes) the gas industry, and lack of producer restraint.

Risks to forecasted demand vary by the demand category.  Risks to industrial demand center on continued recovery from the recession.  Risks to LNG exports depend on a combination of global gas markets and local pricing.  Risks to the expectation of continued strong natural gas demand for power burn center on any carbon legislation, the future of the U.S. coal industry, and policy support for renewable resources.

The upward risks to the Henry Hub price forecast are tempered by the abundant supply of gas available at low prices, and the downward risks are tempered by the real (albeit declining) cost of extraction.  Price movements in the natural gas market will elicit supply-side responses to help balance the market. Further price risk moderation and market balancing is provided on the demand-side by the flexibility and price sensitivity of gas burn for power demand and LNG exports.  All of these factors should combine to keep prices rangebound, while allowing for some natural deviations, around $3.00/MMBtu through FY 2019.

#### 2.3.1.4 The Basis Differential Forecast

Table 1 shows the basis differential forecast for the 11 trading hubs in the Western U.S. used by AURORAxmp®.  The location of natural gas production growth can dramatically change basis relationships as traditional pipeline flows are altered and even reversed.  Production levels in the Rocky Mountains, Western Canada, Western Texas/Southeastern New Mexico, and, increasingly, the Appalachian region directly impact the relationships among Western hubs. Additionally, pipeline transportation availability and cost can impact basis relationships.

In general, relationships between the regional hubs are expected to remain largely unchanged over the rate period, but basis values across the region to Henry Hub are anticipated to change based on the expectation of escalating competition between WCSB, Appalachian, Permian and Rockies gas combined with steady Pacific Northwest demand and declining Southwest demand.

With confidence increasing that significant NE pipeline expansion will occur within the rate period, Appalachian gas is expected to gain market share in eastern Canada and the Midwest U.S. Midwest gas will be pushed south and west into the Rockies, and each source of gas will be forced to discount their prices in an attempt to stay competitive. Larger than expected amounts of Permian gas will also be pushing up into the Midwest and west into California, with the same end result of lowering regional gas prices. It is expected that AECO will have to discount its own gas in an attempt to remain competitive in east Canada, the Midwest, and along the West Coast.

The AECO discount will push through to Kingsgate, Sumas, and Stanfield. These four bases are expected to maintain their historical price relationships to each other, such that gas is incented to flow from Canada south to major demand centers.

The Opal and San Juan bases, representing two producing areas where output is in relative decline, are expected to maintain their lowered basis level over the rate period. Recently enhanced pipelines such as the Rockies Express Pipeline (REX) have given shippers the ability to reverse flow to send Marcellus natural gas east to west, contrary to the pipeline's original west-to-east design and contracts. Appalachian flows westward continue to grow, reducing the amount of Rocky Mountain gas that can economically be delivered eastward. Additional pressure is being placed on the Opal basis by WCSB gas, displacing traditional flows west into Stanfield.

The PG&E Citygate basis will likely remain at a premium compared to other gas hubs in the region, as strong Northern California natural gas demand continues, and as a result its expected basis decline is the lowest of the hubs in this forecast. The continued relative strength of the PG&E Citygate basis will keep the Malin basis strong enough to continue to support sufficient gas flow into Northern California.

The Southern California hubs of Topock, Ehrenberg, and Southern California Citygate are all expected to see lower basis values during the rate period. Renewables growth will continue to erode natural gas market share, negating demand growth, and it now appears unlikely that Aliso Canyon will ever resume normal operations, thereby eliminating a large amount of Southern California injection-season demand.

#### 2.3.1.5 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 875 natural gas price forecasts, and presumes that the gas price forecast represents the median of the resultant 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 875 simulated forecasts is randomly sampled to provide the Henry Hub natural gas price forecast input for each game in AURORAxmp®.

The distribution of simulated natural gas prices is aggregated by month prior to being input into AURORAxmp® because RAM2018 and the TPP calculations use only monthly electricity prices from AURORAxmp® and the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices. The median, 5th, and 95th percentiles of the forecast distribution are reported in Figure 6.

### 2.3.2 Load Forecasts Used in AURORAxmp®

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

#### 2.3.2.1 Load Forecast

AURORAxmp® uses a WECC-wide, long-term load forecast as the base load forecast. Default AURORAxmp® forecasts are used for areas outside the U.S. BPA produced a monthly load forecast for each balancing authority in the WECC within the U.S. for the rate period. Default AURORAxmp® forecasts are used for Canada and Mexico. As AURORAxmp® uses a cut-plane topology (*see* Figure 7) that does not directly correspond to the WECC balancing authorities, it is necessary to map the balancing authority load forecast onto the AURORAxmp® 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 AURORAxmp®. When referring to the load model, this Study is referring to the combination of these models.

#### 2.3.2.3 Yearly Load Model

The annual load model addresses variability in loads created by long-term economic patterns; that is, it incorporates variability at the yearly 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 AURORAxmp® 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, and the Desert Southwest (which comprises all AURORAxmp® areas not listed in the other three). 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 1993 to 2014 and aggregated into the regions described above. The model estimates the load in each region using a time series econometric model. Once the model is estimated, the parameters of the model are used to generate simulated load growth patterns for each AURORAxmp® 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, AURORAxmp® requires factors for each month of a forecast year that, when multiplied by the annual load forecast, yield the monthly loads, also 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 series of these factors for the duration of the forecast period. The monthly load model takes as given the historical monthly load for each AURORAxmp® zone, normalized by their annual averages and centered on zero. These historical load factors, which average to zero for any given year, constitute the observations used to calibrate a statistical model that generates a distribution of monthly load factors.

#### 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 AURORAxmp® zone from 2002 to 2014. The model groups these hourly load observations by week and month, and each group of week-long hourly load observations constitutes a sample for its respective month. The model then normalizes the historical hourly loads by their monthly averages, so the sample space is composed of hourly factors with an average of 1, and then uses a simple bootstrap with replacement to draw sets of week-long, hourly observations from each month. Each draw thus comprises 9,072 hours (54 weeks), with an average of 1. 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 AURORAxmp® runs.

### 2.3.3 Hydroelectric Generation

Hydroelectric generation represents a substantial portion of the average generation in the PNW region and thus is a primary driver of Mid-C electricity prices in AURORAxmp®. Therefore, fluctuations in its output can have a substantial effect on the marginal generator.

#### 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-18-FS-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 80 records of PNW monthly hydroelectric generation, each one year long, 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 2018) 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 2019 *(i.e.,* if the model uses 1929 for FY 2018, then it selects 1930 for FY 2019). Should the model sample 2008 for FY 2018, it uses 1929 for FY 2019. 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 AURORAxmp® 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 AURORAxmp® 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-18-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 AURORAxmp® 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 AURORAxmp® default of $1.74/MWh, 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, 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 would be curtailed.

#### 2.3.3.5 Hydro Shaping

AURORAxmp® 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. AURORAxmp® 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 AURORAxmp® 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, AURORAxmp® 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 AURORAxmp® settings and reflect observed constraints to the degree to which the system can more realistically shape hydroelectric generation.

To implement this ratio in AURORAxmp®, 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 AURORAxmp®, 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 2006 to 2016. Second, the model is implemented in AURORAxmp® 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

AURORAxmp® models wind generation as a must-run resource with a minimum capacity of 40 percent. This assumption implies that, for any given hour, AURORAxmp® dispatches 40 percent of the available capacity independent of economic fundamentals and dispatches the remaining 60 percent as needed. During the BP-18 rate period, BPA expects about 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 Hourly Wind Generation Risk

The PNW Hourly Wind Generation Risk Model simulates the uncertainty in wind generation output. The uncertainty is derived by averaging the observed output of wind plants within the BPA balancing authority area every five minutes for each hour and converting the data into hourly capacity factors.  The source of these data is BPA's external website, www.bpa.gov. These data cover the period from 2006 through 2015.  The model implements 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, each of which includes 8,784 hours, to create a complete wind year. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select AURORAxmp® zones.  This approach captures potential variations in annual, monthly, and hourly wind generation.

### 2.3.5 Thermal Plant Generation

The thermal generation units in AURORAxmp® often drive the marginal unit price, whether the units are natural gas, coal, or nuclear.  With the exception of CGS generation, operation of thermal resources in AURORAxmp® is based on the EPIS-supplied database labeled North American DB 2016v5.

#### 2.3.5.1 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-18-FS-BPA-03, § 3.1.3.  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 output levels 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-18-FS-BPA-05, § 4.1.1) and AURORAxmp®, 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.

### 2.3.6 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 AURORAxmp®. BPA then adds sufficient generic resources to this stack to meet state renewable portfolio standards. This methodology has been updated for BP-18 to account for zonal variation of wind and solar resource capacity factors, ensuring generic renewable resource additions are better aligned with expectations. No custom modifications were made to EPIS default renewable generation shapes, but North American DB2016v5 included updated default solar shapes.

Second, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast, published February 2017. The corresponding zonal load forecasts are 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 AURORAxmp®.

Finally, AURORAxmp® has logic capable of adding and retiring resources based upon economics. In a Long Term Study, AURORAxmp® 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 default annual retirement limits; 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. AURORAxmp® thus ensures that resources are added when economic circumstances justify. AURORAxmp® adds no new thermal resources to the PNW during the BP-18 rate period. The latest database, North American DB 2016v5, was incorporated for the BP-18 analysis. This database includes more restrictive default annual retirement limits that results in fewer economic thermal resource retirements through the BP-18 rate period.

#### 2.3.7 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 AURORAxmp®, all wind resource dispatch costs are set to -$23/MWh, 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 AURORAxmp® default spread between wind and solar resource dispatch costs. The AURORAxmp® default dispatch cost of solar resources is 36 cents higher than wind; this default spread is applied to all solar resources, resulting in a dispatch cost of -$22.64 /MWh.

### 2.3.8 Transmission Capacity Availability

In AURORAxmp®, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 2 shows the AURORAxmp® 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 BC Intertie are based on historical intertie reports posted on the BPA OASIS website from 2003 through 2015. The ratings for the rest of the interconnections are based on North American DB 2016v5.

#### 2.3.8.1 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 2003 through 2015. 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. This process repeats until an 8,784-hour record has been constructed. The model generates 200 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 200 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 AURORAxmp® 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.

#### 2.3.9 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 beginning at $10 per metric ton of $CO_2$ emissions in 2012 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 AURORAxmp® by applying the auction floor prices to California resources using AURORAxmp® 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 $13.60, $14.53, and $15.50 per metric ton of $CO_2$ emissions (nominal) for calendar years 2017, 2018, and 2019, 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. While the carbon adders for California resources substantially increase prices in California zones, the wheeling adders increase the cost of sending energy to California, thereby preventing major shifts in energy flows. Ultimately, prices at Mid-C do not change significantly, but the spreads between prices at Mid-C and California trading hubs better reflect the real-world price impacts of California's carbon market, enabling more accurate estimates of BPA revenue generated from sales of secondary energy to California.

### 2.4 Market Price Forecasts Produced By AURORAxmp®

Two electricity price forecasts are created using AURORAxmp®. 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 8 shows the FY 2018 through FY 2019 monthly average HLH and LLH prices from the market price forecast. Figure 9 shows the FY 2018 and FY 2019 monthly average HLH and LLH prices from the critical water forecast. Furthermore, Tables 3 and 4 present average Mid-C prices by water year for use in the Spill Surcharge. Power Rate Study BP-18-FS-BPA-01, § 4.1.1.5.

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-18-FS-BPA-05, and numerous components of the Power Rates Study, BP-18-FS-BPA-01.

**DOCUMENTATION**

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

| | FY 2018 | FY 2019 |
|---|---|---|
| Henry | 3.12 | 3.00 |
| AECO | -0.89 | -0.82 |
| Kingsgate | -0.42 | -0.45 |
| Malin | -0.24 | -0.24 |
| Opal | -0.31 | -0.31 |
| PG&E | 0.23 | 0.23 |
| SoCal City | 0.02 | 0.03 |
| Ehrenberg | -0.15 | -0.14 |
| Topock | -0.15 | -0.14 |
| San Juan | -0.34 | -0.32 |
| Stanfield | -0.32 | -0.32 |
| Sumas | -0.41 | -0.41 |

## 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-17** | 2644652 | 1019788 | 4273875 | 331646 | 18500590 | 110952 | 731056 | 346993 | 305891 | 1286938 | 2304350 | 1953666 | 911493 | 4981571 |
| 4 | **Nov-17** | 2257672 | 1145977 | 5031565 | 371200 | 17352450 | 144564 | 672997 | 350447 | 254424 | 1372580 | 2140788 | 1833184 | 963502 | 5228522 |
| 5 | **Dec-17** | 2535223 | 1304837 | 5616643 | 413198 | 18394360 | 182143 | 719423 | 400429 | 265210 | 1607524 | 2309797 | 2002293 | 1063587 | 5731447 |
| 6 | **Jan-18** | 2547329 | 1268178 | 5509330 | 413132 | 18015930 | 182726 | 722815 | 400248 | 262332 | 1575494 | 2249858 | 2010102 | 1082855 | 5760271 |
| 7 | **Feb-18** | 2237022 | 1095779 | 4764958 | 351013 | 16214280 | 139858 | 649263 | 355540 | 242492 | 1362853 | 2026344 | 1776138 | 960536 | 5069422 |
| 8 | **Mar-18** | 2367991 | 1088409 | 4674363 | 345809 | 17598100 | 116540 | 696305 | 345707 | 259012 | 1325826 | 2207727 | 1879421 | 978378 | 5155706 |
| 9 | **Apr-18** | 2394621 | 1004157 | 4464067 | 322059 | 16972240 | 107642 | 700488 | 359545 | 261484 | 1291558 | 2110562 | 1806896 | 872452 | 4808056 |
| 10 | **May-18** | 2796268 | 1013411 | 4495691 | 319281 | 18276360 | 112347 | 764327 | 387729 | 337934 | 1600655 | 2273468 | 2148753 | 879145 | 4904336 |
| 11 | **Jun-18** | 3108837 | 1000239 | 4478601 | 311832 | 19589180 | 110971 | 837025 | 401945 | 393089 | 1728651 | 2445546 | 2587159 | 892865 | 5079799 |
| 12 | **Jul-18** | 3698334 | 1087481 | 4733653 | 332835 | 22440040 | 133829 | 917952 | 442680 | 454700 | 2111893 | 2731227 | 3091860 | 1017204 | 5821246 |
| 13 | **Aug-18** | 3660216 | 1088668 | 4626906 | 332837 | 22771450 | 134343 | 926317 | 437287 | 451262 | 1978101 | 2783413 | 2973417 | 980638 | 5704123 |
| 14 | **Sep-18** | 3127773 | 979195 | 4200372 | 313927 | 20493840 | 109210 | 809271 | 370083 | 389877 | 1564346 | 2560722 | 2401922 | 872062 | 4882518 |
| 15 | **Oct-18** | 2683104 | 1026278 | 4313267 | 334171 | 18341180 | 112690 | 745186 | 355038 | 310137 | 1301847 | 2270287 | 1989032 | 920779 | 5025627 |
| 16 | **Nov-18** | 2296124 | 1152452 | 5073237 | 373723 | 17210410 | 146302 | 687127 | 358469 | 258982 | 1387489 | 2110340 | 1868550 | 972776 | 5272446 |
| 17 | **Dec-18** | 2573676 | 1311296 | 5660076 | 415718 | 18236560 | 183881 | 733553 | 408428 | 269700 | 1622433 | 2275563 | 2037660 | 1072849 | 5775239 |
| 18 | **Jan-19** | 2584957 | 1274537 | 5548660 | 415014 | 17985730 | 184285 | 736699 | 408224 | 268409 | 1590267 | 2240066 | 2041271 | 1091157 | 5804372 |
| 19 | **Feb-19** | 2274650 | 1102123 | 4802060 | 352892 | 16196540 | 141417 | 663148 | 363494 | 248482 | 1377626 | 2018785 | 1807307 | 968826 | 5113392 |
| 20 | **Mar-19** | 2405618 | 1094738 | 4711200 | 347685 | 17570790 | 118099 | 710190 | 353638 | 265071 | 1340599 | 2198312 | 1910590 | 986655 | 5199547 |
| 21 | **Apr-19** | 2432249 | 1010471 | 4500279 | 323932 | 16949260 | 109200 | 714373 | 367454 | 267552 | 1306331 | 2102104 | 1838065 | 880718 | 4851767 |
| 22 | **May-19** | 2820161 | 1019710 | 4532003 | 321152 | 18257030 | 113906 | 778211 | 395616 | 344329 | 1620538 | 2263341 | 2174968 | 887398 | 4947919 |
| 23 | **Jun-19** | 3132730 | 1006523 | 4514868 | 313700 | 19560770 | 112529 | 850910 | 409810 | 399719 | 1748534 | 2433657 | 2613373 | 901106 | 5123255 |
| 24 | **Jul-19** | 3722226 | 1093751 | 4770691 | 334701 | 22391920 | 135387 | 931837 | 450524 | 461593 | 2131776 | 2716429 | 3118075 | 1025433 | 5864575 |
| 25 | **Aug-19** | 3684109 | 1094923 | 4663628 | 334701 | 22721030 | 135902 | 940202 | 445109 | 458139 | 1997984 | 2768064 | 2999632 | 988856 | 5747326 |
| 26 | **Sep-19** | 3151666 | 985436 | 4235821 | 315788 | 20459170 | 110769 | 823155 | 377883 | 396487 | 1584229 | 2547599 | 2428137 | 880267 | 4925595 |

# 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-17** | 1750627 | 922638 | 3360494 | 2021410 | 831848 | 1219663 | 1023744 | 2393725 | 1220192 | 222160 | 411853 | 2047973 | 711318 | 73259 |
| 30 | **Nov-17** | 1891428 | 926363 | 3413712 | 2320179 | 926508 | 1191493 | 1036938 | 2061322 | 1161106 | 197829 | 483802 | 2104949 | 640812 | 82881 |
| 31 | **Dec-17** | 2105839 | 1037426 | 3834616 | 2554436 | 977229 | 1363033 | 1149340 | 2324772 | 1262362 | 208685 | 532808 | 2329945 | 723449 | 89947 |
| 32 | **Jan-18** | 2075783 | 1028017 | 3780109 | 2557507 | 1014415 | 1337460 | 1139311 | 2374520 | 1255713 | 206699 | 527437 | 2284884 | 713971 | 92815 |
| 33 | **Feb-18** | 1815906 | 907175 | 3351507 | 2246581 | 888281 | 1147904 | 1025677 | 2061039 | 1130926 | 185971 | 471391 | 2079258 | 630009 | 81970 |
| 34 | **Mar-18** | 1841707 | 945246 | 3475712 | 2217676 | 893080 | 1218282 | 1073227 | 2174552 | 1184423 | 200046 | 468493 | 2157080 | 664579 | 81606 |
| 35 | **Apr-18** | 1727435 | 891895 | 3240324 | 2011890 | 833948 | 1136822 | 1011871 | 2183305 | 1129358 | 196501 | 426394 | 2011806 | 669506 | 71343 |
| 36 | **May-18** | 1727804 | 901207 | 3287250 | 1883875 | 801448 | 1225194 | 1045579 | 2608252 | 1299586 | 238663 | 398448 | 2072818 | 763734 | 73572 |
| 37 | **Jun-18** | 1665574 | 975552 | 3470409 | 1824138 | 773946 | 1422907 | 1070677 | 2990811 | 1485573 | 259454 | 379503 | 2173503 | 861748 | 76447 |
| 38 | **Jul-18** | 1845543 | 1103810 | 4050719 | 1905827 | 800257 | 1679436 | 1177534 | 3452462 | 1685206 | 293250 | 388370 | 2434073 | 925811 | 94245 |
| 39 | **Aug-18** | 1867984 | 1092860 | 3910470 | 1945576 | 796985 | 1658499 | 1176794 | 3413155 | 1664959 | 290203 | 396711 | 2396204 | 877566 | 86438 |
| 40 | **Sep-18** | 1703449 | 951219 | 3301813 | 1855491 | 768488 | 1411357 | 1046584 | 2915920 | 1468605 | 257340 | 382892 | 2067461 | 790170 | 75973 |
| 41 | **Oct-18** | 1763938 | 933606 | 3376105 | 2026953 | 833743 | 1217970 | 1044479 | 2437916 | 1235465 | 223815 | 415694 | 2061552 | 719598 | 73259 |
| 42 | **Nov-18** | 1904738 | 937341 | 3429323 | 2325721 | 928403 | 1190010 | 1057673 | 2105405 | 1176234 | 199637 | 488183 | 2118407 | 649069 | 82881 |
| 43 | **Dec-18** | 2119150 | 1048680 | 3850227 | 2559979 | 979124 | 1360281 | 1170075 | 2368749 | 1277743 | 210419 | 537558 | 2343284 | 731683 | 89947 |
| 44 | **Jan-19** | 2086931 | 1037318 | 3792546 | 2562154 | 1016004 | 1345066 | 1155930 | 2418268 | 1271477 | 208863 | 532015 | 2298105 | 722181 | 92815 |
| 45 | **Feb-19** | 1827054 | 916179 | 3363944 | 2251228 | 889870 | 1155338 | 1042297 | 2104680 | 1146384 | 188195 | 475549 | 2092364 | 638196 | 81970 |
| 46 | **Mar-19** | 1852855 | 954345 | 3488150 | 2222323 | 894669 | 1225780 | 1089846 | 2218089 | 1200016 | 202222 | 472629 | 2170073 | 672743 | 81606 |
| 47 | **Apr-19** | 1738583 | 900863 | 3252762 | 2016538 | 835537 | 1144246 | 1028491 | 2226737 | 1144817 | 198683 | 430216 | 2024688 | 677647 | 71343 |
| 48 | **May-19** | 1738952 | 910199 | 3299687 | 1888523 | 803037 | 1232698 | 1062198 | 2644378 | 1315466 | 241756 | 402060 | 2085591 | 771852 | 73572 |
| 49 | **Jun-19** | 1676722 | 984729 | 3482846 | 1828785 | 775535 | 1430590 | 1087296 | 3026855 | 1501913 | 262475 | 382974 | 2186168 | 869844 | 76447 |
| 50 | **Jul-19** | 1856691 | 1113303 | 4063157 | 1910475 | 801846 | 1687351 | 1194153 | 3488422 | 1702039 | 296160 | 391908 | 2446632 | 933884 | 94245 |
| 51 | **Aug-19** | 1879132 | 1102327 | 3922908 | 1950223 | 798574 | 1666395 | 1193413 | 3449033 | 1681744 | 293114 | 400312 | 2408660 | 885617 | 86438 |
| 52 | **Sep-19** | 1714597 | 960338 | 3314250 | 1860138 | 770077 | 1419029 | 1063203 | 2951717 | 1484908 | 260347 | 386390 | 2079814 | 798198 | 75973 |

**Table 3: BP-18 Final Proposal FY18 Market Price ($/MWh, nominal)**

| | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Water | Table 3: BP-18 Final Proposal FY18 Market Price ($/MWh, nominal) | | | | | | | | | | | |
| 2 | Year | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
| 3 | **1929** | 24.64 | 27.12 | 30.66 | 31.66 | 30.80 | 26.10 | 20.91 | 18.29 | 19.45 | 26.56 | 25.35 | 24.39 |
| 4 | **1930** | 27.73 | 29.04 | 33.92 | 37.03 | 30.01 | 28.25 | 21.44 | 20.90 | 24.92 | 25.59 | 27.04 | 25.72 |
| 5 | **1931** | 27.06 | 28.22 | 32.12 | 31.76 | 34.69 | 28.50 | 24.28 | 20.15 | 24.53 | 25.59 | 26.63 | 25.43 |
| 6 | **1932** | 26.93 | 28.96 | 31.60 | 33.61 | 31.80 | 21.81 | 14.72 | 9.32 | 10.51 | 22.87 | 24.54 | 23.80 |
| 7 | **1933** | 25.32 | 26.36 | 27.47 | 25.31 | 26.03 | 23.62 | 21.92 | 17.32 | 0.12 | 19.50 | 24.90 | 26.20 |
| 8 | **1934** | 24.49 | 23.19 | 22.11 | 19.89 | 23.82 | 19.12 | 15.01 | 16.43 | 18.60 | 24.83 | 27.55 | 25.08 |
| 9 | **1935** | 26.45 | 28.12 | 30.50 | 25.00 | 24.97 | 22.44 | 20.44 | 16.11 | 17.31 | 20.00 | 23.52 | 25.58 |
| 10 | **1936** | 25.97 | 27.07 | 32.60 | 34.75 | 30.01 | 24.85 | 19.20 | 8.40 | 13.13 | 24.36 | 26.00 | 24.92 |
| 11 | **1937** | 26.20 | 28.48 | 33.37 | 37.23 | 34.68 | 28.03 | 24.42 | 20.02 | 21.69 | 28.35 | 27.86 | 26.22 |
| 12 | **1938** | 26.34 | 28.63 | 30.42 | 28.13 | 26.99 | 22.37 | 15.28 | 10.56 | 17.55 | 22.60 | 27.57 | 24.87 |
| 13 | **1939** | 27.27 | 28.85 | 31.75 | 28.38 | 29.01 | 25.38 | 19.28 | 17.68 | 22.92 | 25.89 | 27.95 | 25.83 |
| 14 | **1940** | 26.11 | 27.73 | 31.27 | 29.90 | 30.56 | 21.73 | 20.69 | 17.67 | 22.92 | 25.90 | 28.12 | 25.18 |
| 15 | **1941** | 26.28 | 26.88 | 29.81 | 33.30 | 31.26 | 27.69 | 22.99 | 19.28 | 22.67 | 26.43 | 28.04 | 25.99 |
| 16 | **1942** | 26.49 | 26.20 | 27.98 | 27.04 | 27.23 | 25.01 | 20.77 | 18.21 | 18.28 | 20.76 | 24.71 | 23.18 |
| 17 | **1943** | 27.80 | 29.86 | 30.69 | 27.04 | 26.20 | 22.30 | 8.71 | 13.28 | 1.78 | 16.82 | 24.35 | 24.96 |
| 18 | **1944** | 25.45 | 26.86 | 31.36 | 31.51 | 29.40 | 26.67 | 23.30 | 21.72 | 26.23 | 28.36 | 28.59 | 26.56 |
| 19 | **1945** | 27.15 | 29.24 | 33.06 | 32.47 | 32.50 | 28.36 | 25.58 | 17.15 | 16.81 | 28.04 | 27.02 | 25.34 |
| 20 | **1946** | 26.50 | 27.04 | 30.14 | 28.13 | 27.07 | 22.56 | 14.76 | 10.36 | 17.23 | 20.14 | 25.40 | 24.33 |
| 21 | **1947** | 25.91 | 27.35 | 25.78 | 25.40 | 23.90 | 21.11 | 18.91 | 13.54 | 16.71 | 21.79 | 24.99 | 24.29 |
| 22 | **1948** | 23.26 | 26.53 | 28.18 | 25.23 | 26.13 | 23.19 | 18.71 | 5.25 | 1.64 | 21.30 | 22.81 | 25.10 |
| 23 | **1949** | 25.47 | 27.21 | 29.90 | 28.63 | 28.40 | 22.01 | 17.18 | 7.05 | 16.44 | 26.89 | 27.80 | 25.42 |
| 24 | **1950** | 25.77 | 26.32 | 29.89 | 24.73 | 23.73 | 21.11 | 16.87 | 14.68 | 1.07 | 13.40 | 23.39 | 25.93 |
| 25 | **1951** | 23.31 | 22.78 | 22.12 | 19.56 | 17.46 | 15.98 | 14.78 | 10.59 | 15.66 | 18.89 | 24.01 | 23.84 |
| 26 | **1952** | 23.37 | 26.80 | 26.27 | 25.50 | 25.04 | 21.77 | 12.13 | 2.16 | 13.31 | 21.73 | 25.58 | 26.11 |
| 29 | **1953** | 26.18 | 27.94 | 32.30 | 26.79 | 24.27 | 23.38 | 20.27 | 15.10 | 1.71 | 18.68 | 24.45 | 24.32 |
| 30 | **1954** | 25.43 | 27.28 | 27.08 | 24.52 | 23.48 | 21.22 | 19.32 | 13.93 | 11.78 | 15.03 | 22.08 | 22.62 |
| 31 | **1955** | 25.95 | 25.76 | 27.72 | 28.55 | 26.51 | 26.53 | 21.23 | 16.74 | 0.26 | 15.15 | 23.50 | 25.75 |
| 32 | **1956** | 24.94 | 24.92 | 25.01 | 22.90 | 22.17 | 19.14 | 13.92 | 5.20 | 0.61 | 20.33 | 24.08 | 26.20 |
| 33 | **1957** | 25.22 | 29.17 | 28.43 | 28.28 | 27.29 | 23.11 | 18.82 | 2.34 | 2.22 | 26.83 | 28.43 | 26.96 |
| 34 | **1958** | 27.49 | 29.18 | 33.04 | 26.63 | 25.22 | 22.21 | 17.78 | 6.54 | 6.81 | 24.08 | 26.36 | 25.73 |
| 35 | **1959** | 25.27 | 25.87 | 26.11 | 24.03 | 23.66 | 21.01 | 18.53 | 15.11 | 9.31 | 18.56 | 23.85 | 21.43 |
| 36 | **1960** | 21.03 | 23.90 | 26.40 | 27.48 | 27.77 | 24.67 | 14.28 | 18.90 | 14.22 | 23.54 | 26.83 | 26.34 |
| 37 | **1961** | 27.05 | 27.35 | 29.50 | 27.66 | 26.40 | 22.19 | 21.18 | 15.62 | 9.98 | 24.62 | 26.47 | 26.24 |
| 38 | **1962** | 26.01 | 28.26 | 30.10 | 29.13 | 26.96 | 27.41 | 13.97 | 16.10 | 17.91 | 24.07 | 26.31 | 26.36 |
| 39 | **1963** | 23.94 | 25.22 | 25.58 | 25.14 | 23.91 | 22.87 | 20.50 | 15.28 | 15.89 | 20.67 | 24.62 | 23.32 |
| 40 | **1964** | 26.97 | 28.30 | 29.39 | 29.86 | 29.61 | 27.73 | 21.51 | 17.03 | -0.98 | 20.35 | 26.02 | 26.40 |
| 41 | **1965** | 23.88 | 27.41 | 25.57 | 21.67 | 18.60 | 18.53 | 16.98 | 10.60 | 16.33 | 21.32 | 23.29 | 24.79 |
| 42 | **1966** | 23.59 | 25.61 | 27.89 | 27.15 | 26.41 | 24.71 | 16.84 | 18.64 | 17.70 | 21.11 | 24.99 | 24.33 |
| 43 | **1967** | 27.11 | 29.11 | 28.79 | 25.92 | 25.10 | 22.04 | 23.00 | 16.22 | 1.13 | 20.94 | 25.47 | 26.53 |
| 44 | **1968** | 24.91 | 26.35 | 29.00 | 25.17 | 24.48 | 21.61 | 23.02 | 18.53 | 12.56 | 22.63 | 25.27 | 23.03 |

**Table 3: BP-18 Final Proposal FY18 Market Price, cont. ($/MWh, nominal)**

| | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 45 | **Water** | **Table 3 (cont): BP-18 Final Proposal FY18 Market Price ($/MWh, nominal)** | | | | | | | | | | | |
| 46 | **Year** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** |
| 47 | **1969** | 22.32 | 22.77 | 26.30 | 24.23 | 22.57 | 22.02 | 13.98 | 4.18 | 13.68 | 22.18 | 26.70 | 26.55 |
| 48 | **1970** | 26.53 | 27.95 | 29.82 | 25.34 | 26.88 | 24.28 | 21.74 | 15.93 | 9.30 | 26.44 | 26.51 | 25.95 |
| 49 | **1971** | 25.45 | 27.41 | 29.60 | 22.21 | 18.17 | 17.68 | 13.87 | 5.34 | 0.22 | 15.23 | 22.58 | 25.77 |
| 50 | **1972** | 26.42 | 28.95 | 29.36 | 22.79 | 20.55 | 6.66 | 13.09 | 6.77 | -0.16 | 16.36 | 21.29 | 24.25 |
| 51 | **1973** | 23.49 | 26.60 | 27.86 | 27.66 | 30.20 | 25.94 | 23.58 | 18.93 | 22.88 | 25.37 | 27.52 | 25.70 |
| 52 | **1974** | 25.10 | 26.00 | 25.57 | 12.80 | 16.28 | 12.63 | 10.46 | 7.32 | -1.15 | 12.07 | 22.20 | 25.28 |
| 53 | **1975** | 27.91 | 27.82 | 30.32 | 26.84 | 25.56 | 23.07 | 21.78 | 11.63 | 3.24 | 14.71 | 25.03 | 24.74 |
| 54 | **1976** | 24.47 | 24.97 | 21.91 | 23.33 | 23.22 | 18.80 | 15.74 | 7.13 | 13.12 | 19.04 | 21.10 | 21.67 |
| 55 | **1977** | 25.33 | 28.20 | 32.70 | 32.47 | 29.64 | 26.41 | 24.30 | 21.72 | 26.35 | 28.28 | 28.20 | 28.61 |
| 56 | **1978** | 26.35 | 27.08 | 27.55 | 26.91 | 25.89 | 23.66 | 16.92 | 13.38 | 19.01 | 22.22 | 26.55 | 22.28 |
| 57 | **1979** | 25.83 | 27.02 | 31.24 | 28.75 | 29.27 | 22.42 | 21.73 | 14.14 | 20.21 | 27.99 | 27.70 | 25.63 |
| 58 | **1980** | 26.46 | 28.03 | 30.39 | 29.19 | 28.27 | 25.17 | 18.60 | 6.15 | 11.40 | 23.81 | 26.55 | 24.22 |
| 59 | **1981** | 27.27 | 28.44 | 27.58 | 26.13 | 25.42 | 26.07 | 23.75 | 17.20 | 7.84 | 20.87 | 23.32 | 24.94 |
| 60 | **1982** | 24.47 | 25.84 | 26.70 | 24.82 | 18.93 | 15.96 | 16.92 | 9.23 | 6.88 | 14.03 | 22.82 | 23.69 |
| 61 | **1983** | 25.23 | 27.45 | 27.98 | 24.40 | 21.74 | 18.20 | 18.59 | 13.16 | 12.65 | 17.76 | 23.88 | 25.07 |
| 62 | **1984** | 25.54 | 24.49 | 28.10 | 26.63 | 25.62 | 21.70 | 15.89 | 13.88 | 5.84 | 20.46 | 24.14 | 24.27 |
| 63 | **1985** | 24.84 | 25.94 | 28.01 | 27.94 | 28.29 | 25.54 | 17.68 | 15.54 | 20.45 | 26.33 | 28.78 | 25.99 |
| 64 | **1986** | 24.51 | 24.17 | 28.75 | 25.74 | 24.73 | 15.84 | 14.31 | 17.47 | 17.65 | 24.94 | 27.29 | 26.28 |
| 65 | **1987** | 26.74 | 26.51 | 27.89 | 28.66 | 30.37 | 23.86 | 22.05 | 15.91 | 20.68 | 26.34 | 27.32 | 25.14 |
| 66 | **1988** | 25.97 | 28.84 | 32.46 | 31.66 | 33.67 | 26.51 | 22.10 | 19.17 | 22.89 | 25.34 | 27.12 | 26.15 |
| 67 | **1989** | 25.75 | 26.52 | 30.28 | 30.85 | 32.30 | 25.17 | 18.85 | 17.75 | 20.47 | 26.02 | 27.92 | 26.42 |
| 68 | **1990** | 28.42 | 28.11 | 30.11 | 26.99 | 25.96 | 22.53 | 18.97 | 18.43 | 13.29 | 22.30 | 23.96 | 25.00 |
| 69 | **1991** | 25.15 | 22.76 | 26.33 | 24.70 | 24.49 | 21.32 | 19.25 | 15.83 | 15.43 | 18.61 | 22.52 | 24.85 |
| 70 | **1992** | 26.38 | 28.48 | 33.08 | 30.98 | 30.75 | 25.10 | 25.06 | 20.48 | 25.31 | 28.24 | 28.20 | 27.25 |
| 71 | **1993** | 27.84 | 28.21 | 32.04 | 32.38 | 35.37 | 25.01 | 20.56 | 14.80 | 19.57 | 25.92 | 26.93 | 25.50 |
| 72 | **1994** | 26.07 | 27.66 | 30.85 | 32.32 | 29.95 | 25.52 | 21.17 | 17.53 | 20.68 | 25.88 | 27.31 | 25.92 |
| 73 | **1995** | 25.64 | 28.08 | 30.97 | 29.12 | 27.04 | 22.86 | 22.05 | 16.32 | 10.44 | 23.77 | 26.45 | 24.88 |
| 74 | **1996** | 24.29 | 23.08 | 17.96 | 17.98 | 16.40 | 11.09 | 11.53 | 7.04 | 12.32 | 18.74 | 22.96 | 23.84 |
| 75 | **1997** | 25.07 | 26.75 | 26.78 | 17.63 | 17.42 | 12.53 | 9.90 | 5.65 | 1.81 | 18.90 | 24.07 | 24.28 |
| 76 | **1998** | 21.24 | 24.92 | 29.32 | 28.52 | 26.33 | 23.29 | 18.68 | 4.40 | 4.16 | 22.64 | 25.80 | 26.16 |
| 77 | **1999** | 27.01 | 29.38 | 27.40 | 22.57 | 21.05 | 17.57 | 17.22 | 14.28 | 2.12 | 16.94 | 21.63 | 24.76 |
| 78 | **2000** | 25.49 | 22.40 | 25.51 | 26.20 | 25.84 | 22.17 | 14.47 | 14.88 | 20.38 | 23.19 | 26.86 | 26.07 |
| 79 | **2001** | 26.37 | 28.75 | 32.04 | 33.62 | 30.16 | 26.48 | 24.20 | 20.97 | 27.72 | 25.99 | 26.99 | 26.54 |
| 80 | **2002** | 26.22 | 27.88 | 31.13 | 30.61 | 30.88 | 25.98 | 19.44 | 17.37 | 10.11 | 20.34 | 26.40 | 25.09 |
| 81 | **2003** | 26.29 | 28.77 | 32.02 | 31.81 | 33.26 | 24.32 | 21.34 | 17.62 | 14.58 | 25.75 | 27.75 | 25.94 |
| 82 | **2004** | 25.46 | 27.16 | 31.23 | 32.31 | 32.93 | 25.64 | 22.62 | 18.47 | 21.12 | 25.50 | 26.75 | 23.85 |
| 83 | **2005** | 24.95 | 27.43 | 27.47 | 27.52 | 26.95 | 25.86 | 21.88 | 15.89 | 18.23 | 23.02 | 25.75 | 24.45 |
| 84 | **2006** | 26.13 | 28.50 | 29.99 | 26.03 | 25.08 | 23.14 | 14.46 | 8.85 | 9.42 | 25.06 | 27.89 | 26.59 |
| 85 | **2007** | 26.18 | 25.87 | 30.10 | 27.66 | 27.50 | 22.80 | 20.19 | 17.82 | 20.60 | 25.34 | 29.91 | 29.31 |
| 86 | **2008** | 25.94 | 27.87 | 31.40 | 30.29 | 29.57 | 25.60 | 22.36 | 13.17 | -2.34 | 24.48 | 26.71 | 27.57 |

## Table 4: BP-18 Final Proposal FY19 Market Price ($/MWh, nominal)

| | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Water** | **Table 4: BP-18 Final Proposal FY19 Market Price ($/MWh, nominal)** | | | | | | | | | | | |
| 2 | **Year** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** |
| 3 | **1929** | 24.50 | 26.81 | 32.34 | 33.18 | 32.31 | 26.10 | 21.34 | 19.44 | 21.12 | 27.59 | 26.85 | 24.92 |
| 4 | **1930** | 24.90 | 25.85 | 30.87 | 34.26 | 30.56 | 27.52 | 20.94 | 19.99 | 24.79 | 24.23 | 26.66 | 25.38 |
| 5 | **1931** | 25.19 | 26.92 | 32.41 | 32.15 | 35.73 | 27.56 | 23.86 | 19.37 | 26.05 | 26.03 | 27.40 | 25.66 |
| 6 | **1932** | 24.34 | 26.50 | 31.17 | 35.70 | 36.21 | 24.55 | 15.72 | 11.52 | 14.46 | 23.13 | 25.42 | 24.24 |
| 7 | **1933** | 24.03 | 24.72 | 27.02 | 25.27 | 24.93 | 23.35 | 21.63 | 17.96 | 5.10 | 18.86 | 24.54 | 26.29 |
| 8 | **1934** | 24.82 | 23.61 | 22.20 | 18.86 | 21.53 | 16.99 | 14.10 | 15.32 | 18.84 | 24.42 | 27.18 | 24.96 |
| 9 | **1935** | 24.07 | 25.65 | 30.32 | 27.50 | 27.93 | 23.92 | 22.89 | 18.16 | 20.60 | 21.65 | 25.82 | 26.49 |
| 10 | **1936** | 24.80 | 26.70 | 33.23 | 36.24 | 33.60 | 27.53 | 21.29 | 12.50 | 17.33 | 25.92 | 27.67 | 26.07 |
| 11 | **1937** | 24.22 | 25.48 | 30.40 | 33.13 | 33.25 | 27.44 | 23.67 | 19.56 | 21.96 | 28.56 | 28.54 | 25.83 |
| 12 | **1938** | 24.95 | 25.80 | 28.20 | 25.62 | 24.57 | 21.97 | 15.32 | 9.84 | 17.71 | 21.19 | 26.28 | 23.70 |
| 13 | **1939** | 24.24 | 25.97 | 30.38 | 27.41 | 29.64 | 25.82 | 19.36 | 18.09 | 23.73 | 25.61 | 28.14 | 25.18 |
| 14 | **1940** | 25.19 | 26.44 | 31.04 | 28.15 | 29.45 | 20.95 | 20.91 | 17.98 | 23.75 | 26.25 | 29.45 | 25.80 |
| 15 | **1941** | 24.19 | 25.92 | 29.43 | 32.21 | 31.38 | 26.62 | 23.71 | 19.15 | 22.97 | 24.85 | 25.76 | 24.41 |
| 16 | **1942** | 25.52 | 25.86 | 27.90 | 27.08 | 28.27 | 24.48 | 20.86 | 17.54 | 18.41 | 21.05 | 25.51 | 24.09 |
| 17 | **1943** | 24.32 | 25.79 | 28.71 | 24.99 | 24.70 | 20.99 | 7.33 | 14.46 | 3.40 | 16.44 | 25.09 | 25.36 |
| 18 | **1944** | 23.54 | 24.97 | 29.51 | 31.32 | 32.61 | 27.50 | 23.24 | 22.13 | 26.97 | 26.89 | 27.53 | 25.81 |
| 19 | **1945** | 25.82 | 26.76 | 31.51 | 31.65 | 31.30 | 26.38 | 24.10 | 15.95 | 17.32 | 26.53 | 27.02 | 25.19 |
| 20 | **1946** | 24.06 | 25.43 | 29.09 | 26.48 | 27.41 | 23.12 | 15.06 | 10.80 | 16.91 | 19.55 | 25.79 | 24.72 |
| 21 | **1947** | 24.48 | 23.77 | 22.94 | 23.69 | 23.05 | 20.61 | 18.21 | 13.94 | 17.79 | 22.34 | 26.61 | 25.74 |
| 22 | **1948** | 19.70 | 23.94 | 27.39 | 23.98 | 26.15 | 22.93 | 19.18 | 6.24 | 5.35 | 19.23 | 21.97 | 24.15 |
| 23 | **1949** | 23.80 | 26.83 | 28.84 | 26.69 | 26.21 | 19.61 | 15.85 | 8.20 | 15.71 | 25.51 | 26.74 | 24.82 |
| 24 | **1950** | 25.26 | 26.46 | 30.72 | 24.16 | 23.06 | 20.08 | 14.81 | 14.13 | 2.68 | 10.77 | 22.57 | 25.66 |
| 25 | **1951** | 22.51 | 22.88 | 23.32 | 21.70 | 19.81 | 16.59 | 14.57 | 10.82 | 17.46 | 19.36 | 26.11 | 25.25 |
| 26 | **1952** | 20.33 | 24.17 | 25.61 | 24.72 | 24.09 | 22.70 | 13.66 | 3.92 | 15.76 | 21.18 | 25.31 | 25.66 |
| 29 | **1953** | 24.65 | 26.85 | 30.85 | 27.12 | 24.52 | 22.77 | 20.18 | 15.23 | 1.99 | 16.52 | 24.29 | 24.07 |
| 30 | **1954** | 22.91 | 24.19 | 25.37 | 22.63 | 23.36 | 19.79 | 17.98 | 13.43 | 12.59 | 12.50 | 20.72 | 20.61 |
| 31 | **1955** | 24.85 | 24.28 | 27.84 | 29.82 | 29.15 | 27.80 | 21.54 | 17.90 | 5.84 | 15.73 | 24.53 | 25.94 |
| 32 | **1956** | 22.27 | 22.37 | 22.93 | 20.16 | 20.30 | 18.32 | 13.60 | 6.49 | 4.80 | 18.65 | 24.29 | 25.91 |
| 33 | **1957** | 23.82 | 27.06 | 26.89 | 28.21 | 28.66 | 23.48 | 19.50 | 5.97 | 7.48 | 26.54 | 29.28 | 28.21 |
| 34 | **1958** | 26.42 | 27.14 | 31.24 | 25.49 | 25.94 | 22.90 | 19.17 | 9.10 | 11.07 | 24.97 | 26.29 | 25.89 |
| 35 | **1959** | 24.52 | 23.92 | 23.93 | 20.82 | 21.68 | 19.41 | 18.11 | 14.95 | 11.61 | 17.60 | 23.17 | 21.37 |
| 36 | **1960** | 19.83 | 22.69 | 25.76 | 26.06 | 25.93 | 22.33 | 12.10 | 16.72 | 14.00 | 20.71 | 25.01 | 24.94 |
| 37 | **1961** | 24.04 | 24.58 | 28.26 | 25.79 | 24.95 | 20.47 | 20.55 | 14.77 | 11.46 | 24.88 | 26.81 | 26.52 |
| 38 | **1962** | 25.58 | 26.38 | 29.16 | 26.27 | 27.18 | 27.75 | 13.69 | 16.43 | 18.55 | 23.49 | 26.11 | 26.27 |
| 39 | **1963** | 24.07 | 25.01 | 27.21 | 26.94 | 24.81 | 24.45 | 21.88 | 17.84 | 19.62 | 23.80 | 28.00 | 26.06 |
| 40 | **1964** | 24.07 | 25.86 | 28.60 | 27.45 | 28.06 | 25.49 | 19.77 | 16.56 | 1.72 | 17.31 | 24.71 | 24.39 |
| 41 | **1965** | 24.59 | 25.57 | 23.50 | 19.78 | 17.76 | 16.79 | 15.42 | 9.60 | 16.17 | 21.58 | 23.36 | 25.61 |
| 42 | **1966** | 23.30 | 26.50 | 28.89 | 28.11 | 28.19 | 24.59 | 17.50 | 19.21 | 19.17 | 21.92 | 25.95 | 25.20 |
| 43 | **1967** | 23.72 | 25.18 | 26.20 | 23.66 | 23.47 | 21.14 | 22.56 | 15.60 | 4.24 | 17.40 | 24.35 | 24.15 |
| 44 | **1968** | 25.20 | 26.25 | 27.85 | 25.15 | 25.77 | 22.86 | 24.31 | 19.66 | 13.83 | 22.11 | 25.24 | 23.59 |

## Table 4:  BP-18 Final Proposal FY19 Market Price, cont. ($/MWh, nominal)

| | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 45 | **Water** | **Table 4 (cont): BP-18 Final Proposal FY19 Market Price ($/MWh, nominal)** | | | | | | | | | | | |
| 46 | **Year** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** |
| 47 | **1969** | 22.62 | 23.91 | 26.26 | 23.02 | 21.97 | 20.73 | 12.67 | 3.88 | 14.44 | 22.19 | 26.68 | 25.50 |
| 48 | **1970** | 25.42 | 26.66 | 31.14 | 26.51 | 27.40 | 23.99 | 21.98 | 16.04 | 9.81 | 26.74 | 26.12 | 25.41 |
| 49 | **1971** | 24.96 | 25.97 | 28.01 | 21.23 | 17.95 | 17.59 | 15.23 | 7.46 | 1.77 | 15.67 | 22.95 | 25.64 |
| 50 | **1972** | 23.20 | 26.55 | 28.24 | 20.90 | 18.54 | 6.44 | 11.27 | 7.21 | 3.67 | 13.82 | 21.41 | 24.35 |
| 51 | **1973** | 23.64 | 26.30 | 27.59 | 26.90 | 28.98 | 25.10 | 22.81 | 18.18 | 23.36 | 24.86 | 27.26 | 24.76 |
| 52 | **1974** | 23.41 | 24.49 | 25.96 | 15.13 | 17.10 | 13.12 | 11.11 | 8.89 | 3.72 | 12.33 | 21.71 | 25.31 |
| 53 | **1975** | 27.55 | 28.21 | 31.31 | 26.07 | 26.33 | 22.91 | 22.78 | 12.92 | 5.49 | 13.40 | 26.13 | 25.00 |
| 54 | **1976** | 20.85 | 21.74 | 20.95 | 21.40 | 22.41 | 18.40 | 14.98 | 7.05 | 13.77 | 17.45 | 21.18 | 20.51 |
| 55 | **1977** | 24.79 | 26.92 | 32.28 | 32.41 | 31.72 | 26.96 | 23.98 | 21.86 | 26.69 | 26.94 | 27.08 | 27.71 |
| 56 | **1978** | 25.96 | 27.05 | 29.01 | 27.66 | 27.41 | 24.63 | 17.46 | 14.89 | 21.20 | 22.64 | 28.26 | 23.44 |
| 57 | **1979** | 23.83 | 26.39 | 30.23 | 26.86 | 29.12 | 22.65 | 23.05 | 15.76 | 21.71 | 28.82 | 28.90 | 26.16 |
| 58 | **1980** | 24.85 | 25.78 | 29.81 | 27.03 | 27.63 | 25.39 | 18.80 | 8.61 | 13.60 | 23.85 | 27.56 | 25.07 |
| 59 | **1981** | 23.70 | 24.67 | 23.84 | 23.21 | 24.37 | 24.96 | 23.51 | 17.53 | 11.10 | 21.48 | 23.94 | 25.38 |
| 60 | **1982** | 23.66 | 25.21 | 27.58 | 24.81 | 18.22 | 13.91 | 16.97 | 11.16 | 8.94 | 13.71 | 24.05 | 24.15 |
| 61 | **1983** | 22.91 | 25.47 | 26.53 | 23.52 | 23.42 | 18.72 | 18.84 | 13.92 | 14.10 | 16.87 | 23.54 | 23.89 |
| 62 | **1984** | 24.17 | 22.51 | 26.14 | 24.26 | 24.11 | 21.11 | 14.60 | 14.42 | 9.64 | 19.69 | 24.58 | 24.01 |
| 63 | **1985** | 22.94 | 23.31 | 27.20 | 27.14 | 27.80 | 24.76 | 17.73 | 16.00 | 20.64 | 25.28 | 29.00 | 25.51 |
| 64 | **1986** | 24.52 | 23.62 | 28.93 | 26.33 | 24.89 | 16.06 | 14.30 | 17.77 | 17.87 | 25.36 | 27.18 | 26.10 |
| 65 | **1987** | 25.41 | 25.38 | 27.44 | 28.94 | 30.45 | 23.58 | 22.50 | 17.03 | 22.34 | 27.30 | 29.41 | 26.79 |
| 66 | **1988** | 24.86 | 26.36 | 31.62 | 31.34 | 33.73 | 25.27 | 21.29 | 18.70 | 22.77 | 24.65 | 27.89 | 26.29 |
| 67 | **1989** | 24.83 | 24.57 | 29.77 | 30.57 | 32.82 | 23.28 | 17.53 | 17.56 | 21.48 | 26.80 | 28.79 | 27.00 |
| 68 | **1990** | 25.96 | 26.37 | 28.02 | 26.90 | 26.74 | 21.99 | 17.90 | 18.00 | 13.88 | 22.41 | 24.14 | 25.39 |
| 69 | **1991** | 23.35 | 21.35 | 25.92 | 24.13 | 23.53 | 20.82 | 19.71 | 17.48 | 18.15 | 19.47 | 25.77 | 27.01 |
| 70 | **1992** | 24.22 | 25.70 | 31.22 | 29.14 | 28.48 | 24.10 | 25.36 | 20.86 | 26.52 | 28.19 | 28.90 | 27.53 |
| 71 | **1993** | 25.35 | 25.64 | 30.35 | 31.81 | 36.29 | 24.51 | 20.75 | 15.96 | 19.64 | 25.36 | 26.61 | 26.04 |
| 72 | **1994** | 25.17 | 25.65 | 29.35 | 31.54 | 31.02 | 26.46 | 22.35 | 17.88 | 21.99 | 25.90 | 28.43 | 25.49 |
| 73 | **1995** | 25.16 | 27.29 | 31.04 | 28.20 | 26.55 | 22.54 | 22.55 | 17.27 | 11.87 | 23.18 | 26.53 | 24.74 |
| 74 | **1996** | 23.48 | 21.08 | 16.81 | 16.93 | 16.01 | 10.65 | 11.97 | 8.14 | 14.11 | 18.23 | 24.09 | 25.58 |
| 75 | **1997** | 22.82 | 24.00 | 24.52 | 14.80 | 14.77 | 11.17 | 10.14 | 4.97 | 5.62 | 15.92 | 23.40 | 23.29 |
| 76 | **1998** | 20.22 | 24.13 | 29.38 | 27.62 | 28.03 | 23.91 | 19.93 | 6.98 | 6.20 | 22.42 | 25.68 | 26.36 |
| 77 | **1999** | 25.21 | 26.80 | 25.59 | 22.05 | 21.07 | 17.59 | 17.05 | 14.59 | 5.87 | 14.37 | 21.75 | 25.09 |
| 78 | **2000** | 23.83 | 21.64 | 25.77 | 25.79 | 25.52 | 22.33 | 15.53 | 15.63 | 20.20 | 21.68 | 25.87 | 26.09 |
| 79 | **2001** | 23.97 | 27.21 | 31.08 | 33.24 | 31.77 | 25.75 | 23.48 | 21.20 | 28.91 | 27.02 | 27.74 | 27.28 |
| 80 | **2002** | 25.15 | 25.63 | 30.20 | 30.40 | 30.21 | 25.09 | 18.02 | 16.80 | 11.29 | 19.07 | 25.50 | 24.36 |
| 81 | **2003** | 24.54 | 25.53 | 29.72 | 28.17 | 30.01 | 20.70 | 18.33 | 15.88 | 14.98 | 24.28 | 26.47 | 24.47 |
| 82 | **2004** | 23.93 | 25.19 | 29.03 | 27.98 | 31.88 | 25.30 | 21.93 | 18.80 | 21.53 | 24.94 | 27.24 | 23.67 |
| 83 | **2005** | 23.84 | 26.30 | 27.36 | 27.02 | 27.20 | 26.65 | 22.68 | 17.04 | 20.31 | 24.83 | 27.90 | 25.90 |
| 84 | **2006** | 24.95 | 23.84 | 25.52 | 23.16 | 23.67 | 21.56 | 13.16 | 9.39 | 10.96 | 22.58 | 27.29 | 26.44 |
| 85 | **2007** | 24.72 | 24.81 | 29.71 | 25.68 | 27.30 | 21.50 | 19.09 | 17.89 | 20.01 | 23.82 | 28.14 | 26.92 |
| 86 | **2008** | 26.57 | 27.38 | 32.41 | 29.91 | 29.17 | 25.16 | 22.02 | 13.67 | 3.69 | 23.08 | 26.42 | 26.82 |

**Figure 1: Basis Locations**

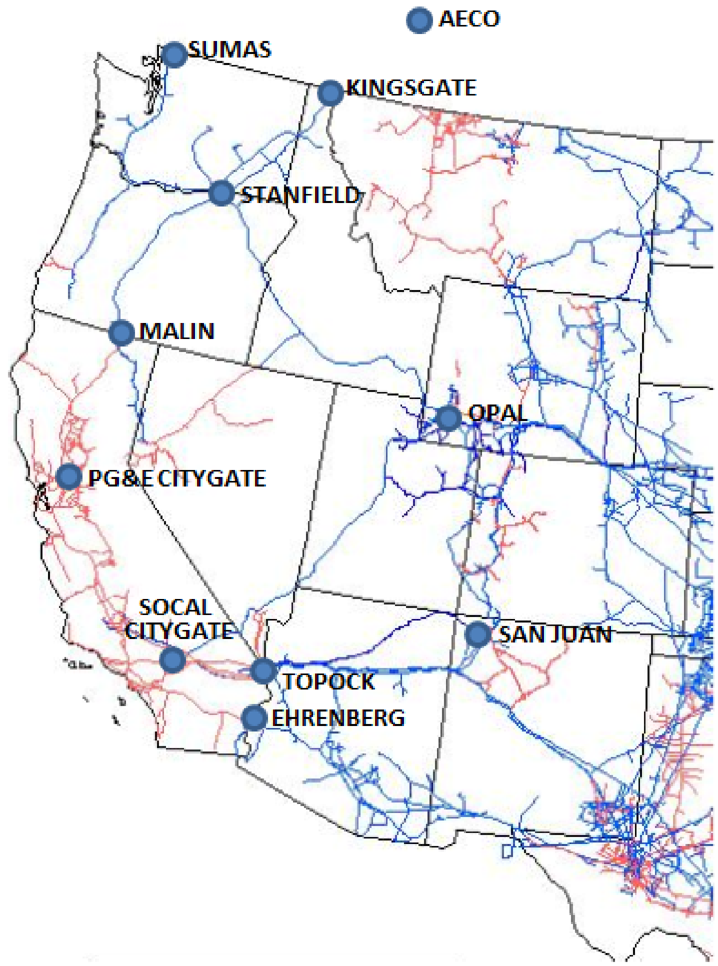


**Figure 2: January 2011 Through May 2017 Monthly Henry Hub Gas Prices**

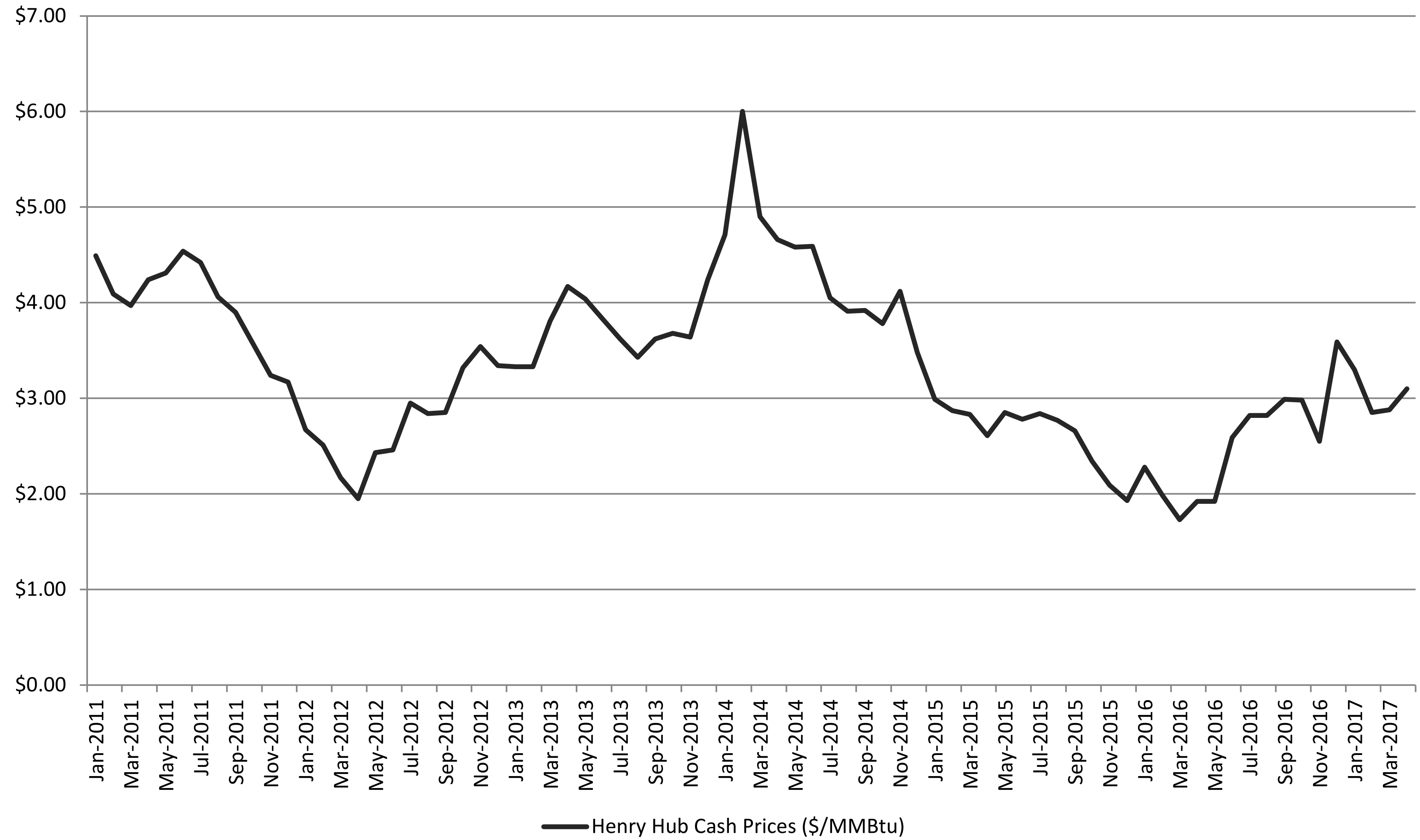
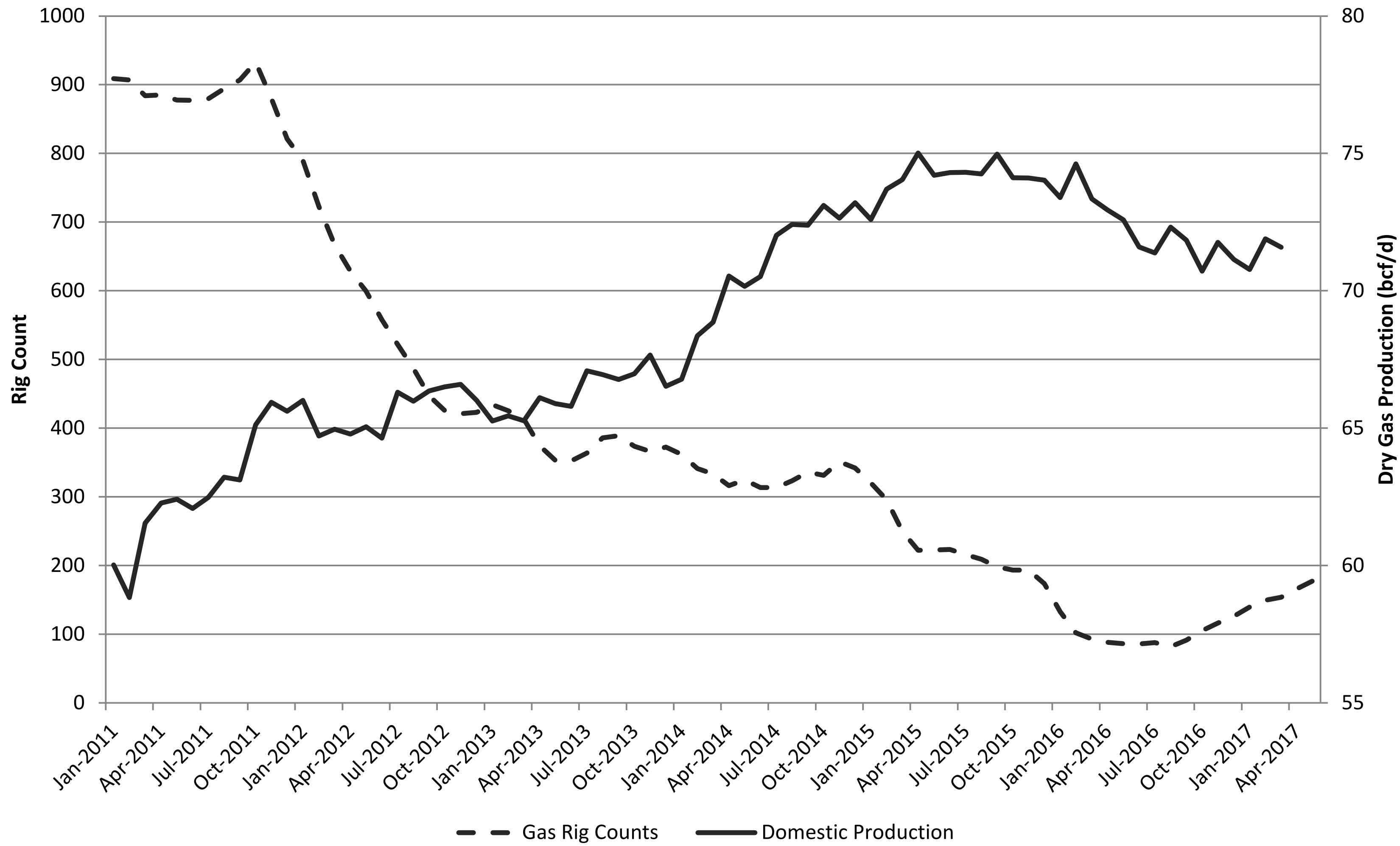
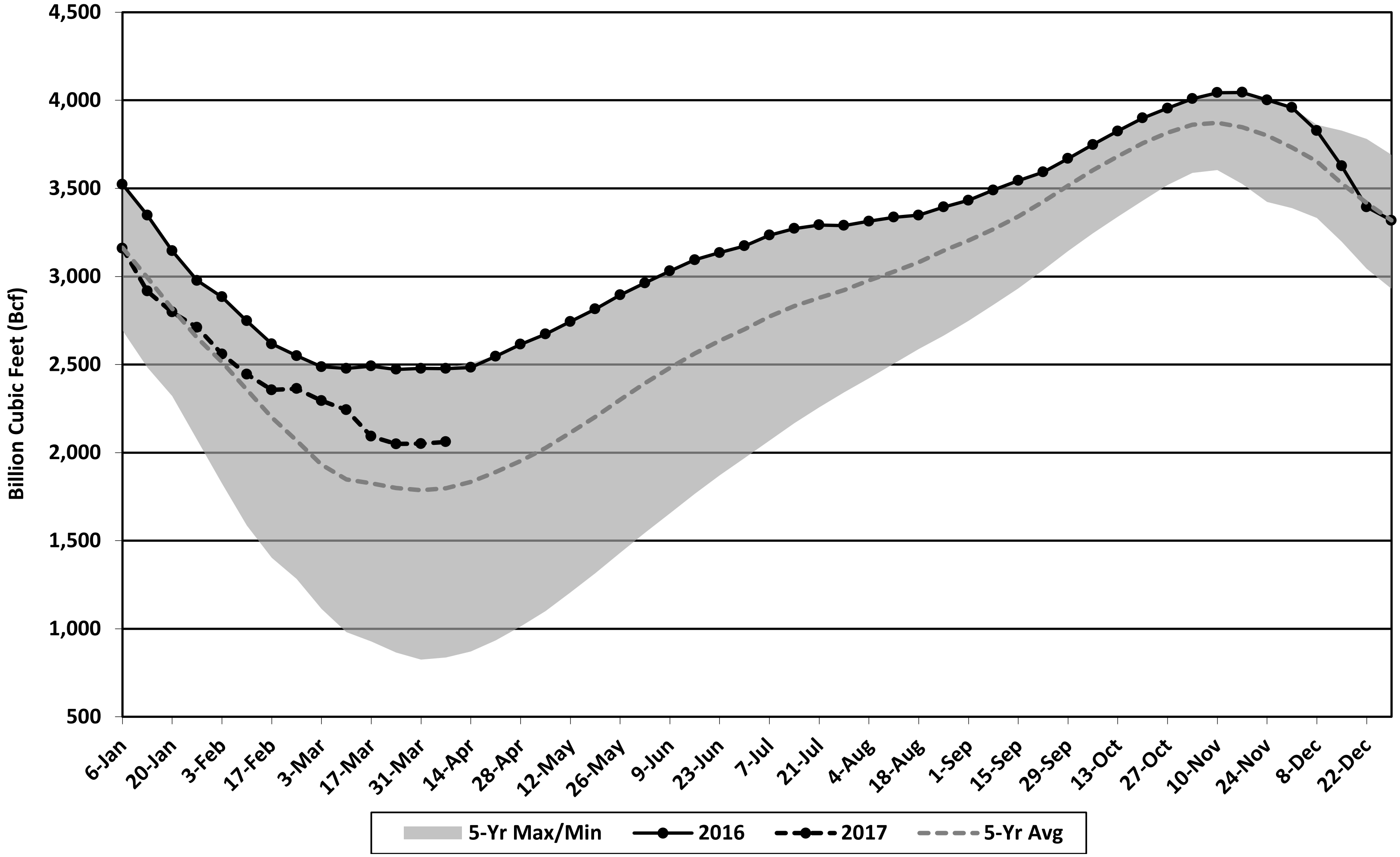


**Figure 3: U.S. Dry Natural Gas Production and Rig Counts**



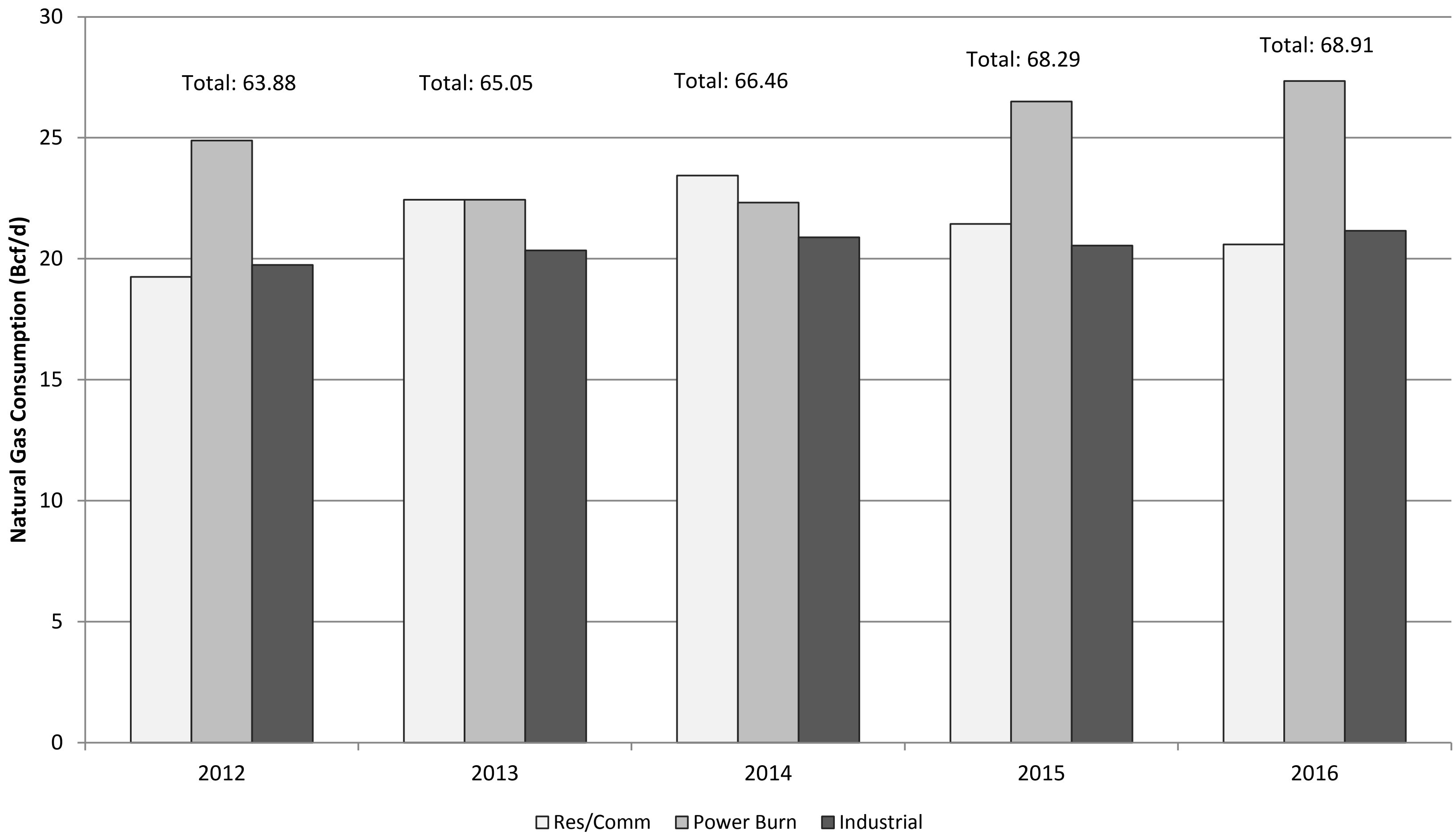

**Source: U.S. Energy Information Administration and Baker Hughes**

**Figure 4: Natural Gas Storage**



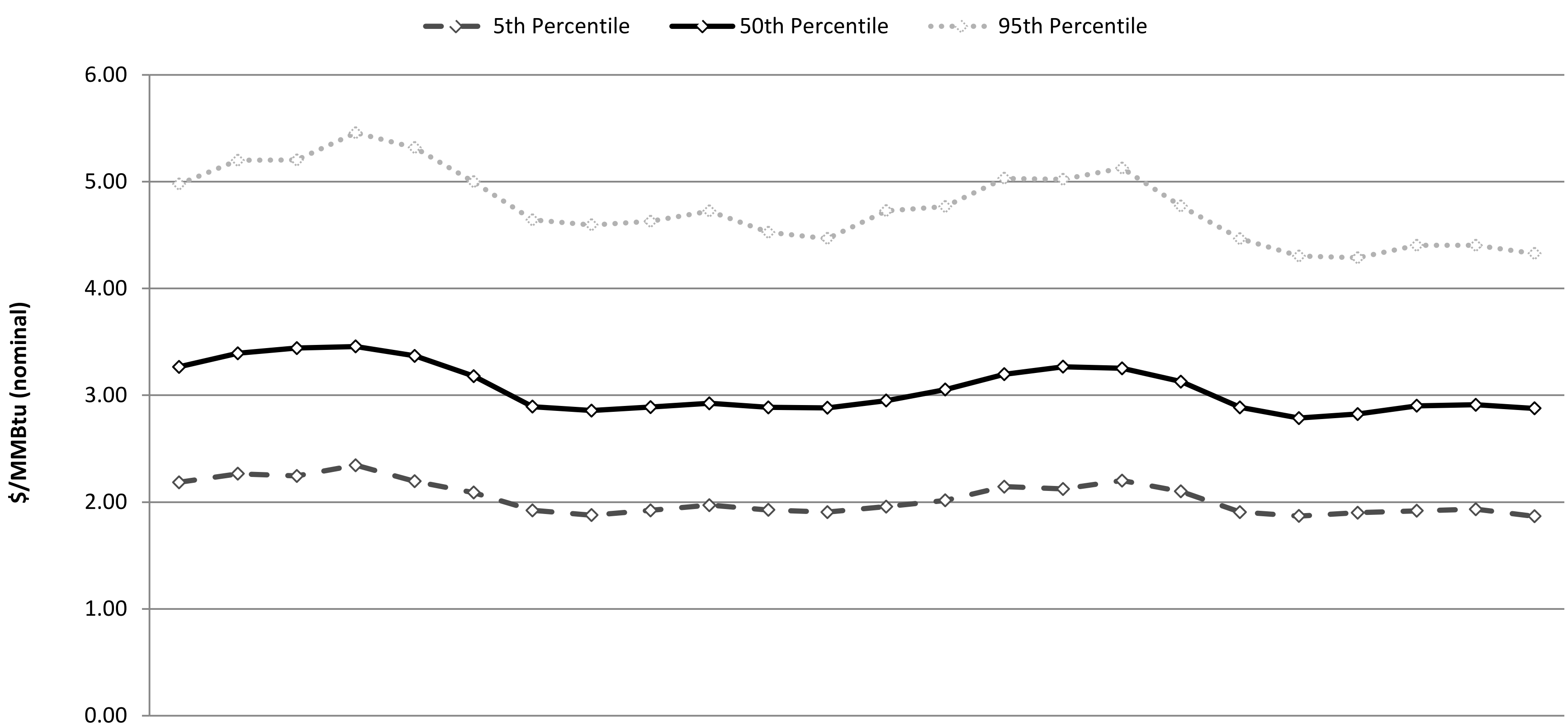

**Source: U.S. Energy Information Administration**

**Figure 5: Natural Gas Domestic Consumption (Demand*)**




**Source: U.S. Energy Information Administration**
***EIA 2016 data was incomplete at the time of publication, so this graph shows only the three major sectors of gas demand. The "Other" cateogry is omitted.**

**Figure 6: Natural Gas Price Risk Model Percentiles**




| | Oct 17 | Nov 17 | Dec 17 | Jan 18 | Feb 18 | Mar 18 | Apr 18 | May 18 | Jun 18 | Jul 18 | Aug 18 | Sep 18 | Oct 18 | Nov 18 | Dec 18 | Jan 19 | Feb 19 | Mar 19 | Apr 19 | May 19 | Jun 19 | Jul 19 | Aug 19 | Sep 19 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5th Percentile | 2.18 | 2.26 | 2.24 | 2.35 | 2.19 | 2.09 | 1.92 | 1.88 | 1.92 | 1.97 | 1.93 | 1.91 | 1.96 | 2.02 | 2.14 | 2.12 | 2.20 | 2.10 | 1.91 | 1.87 | 1.90 | 1.92 | 1.93 | 1.87 |
| 50th Percentile | 3.27 | 3.39 | 3.44 | 3.46 | 3.37 | 3.18 | 2.89 | 2.86 | 2.89 | 2.92 | 2.89 | 2.88 | 2.95 | 3.05 | 3.20 | 3.27 | 3.25 | 3.13 | 2.89 | 2.79 | 2.82 | 2.90 | 2.91 | 2.88 |
| 95th Percentile | 4.98 | 5.20 | 5.20 | 5.46 | 5.32 | 5.00 | 4.64 | 4.60 | 4.63 | 4.73 | 4.53 | 4.47 | 4.73 | 4.77 | 5.03 | 5.02 | 5.13 | 4.77 | 4.47 | 4.30 | 4.29 | 4.40 | 4.40 | 4.33 |

Figure **7: AURORAxmp® Zonal Topology**

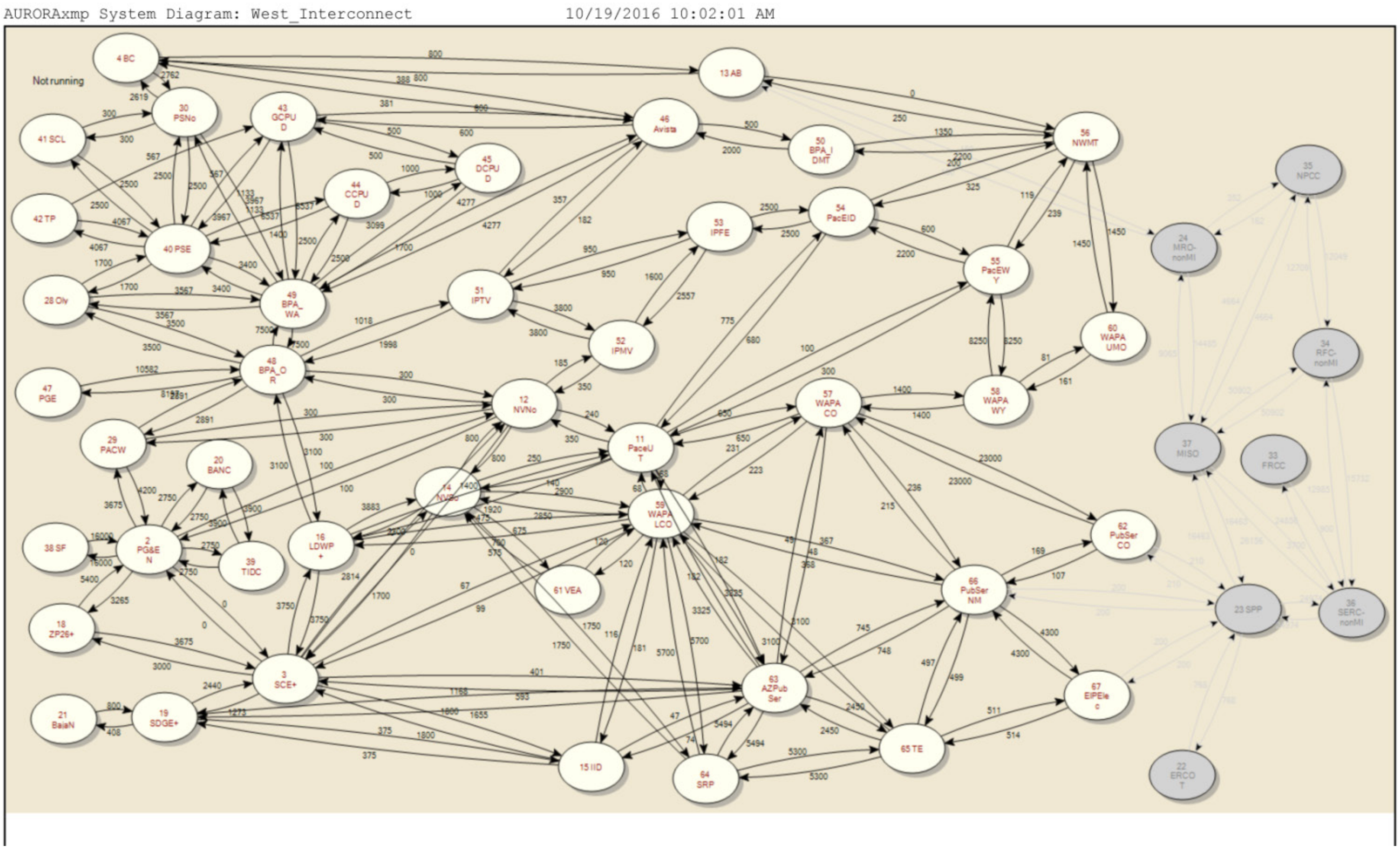
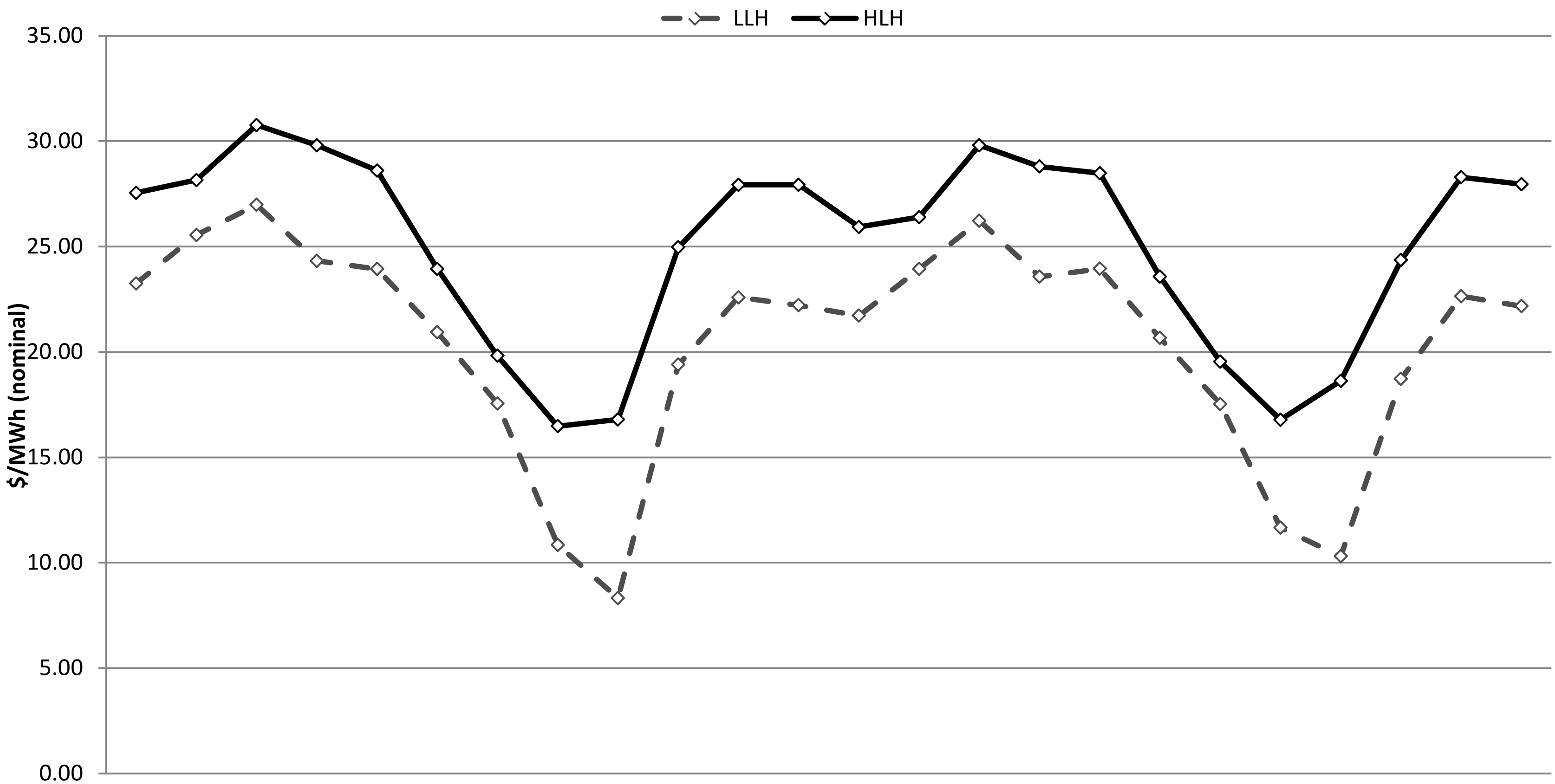
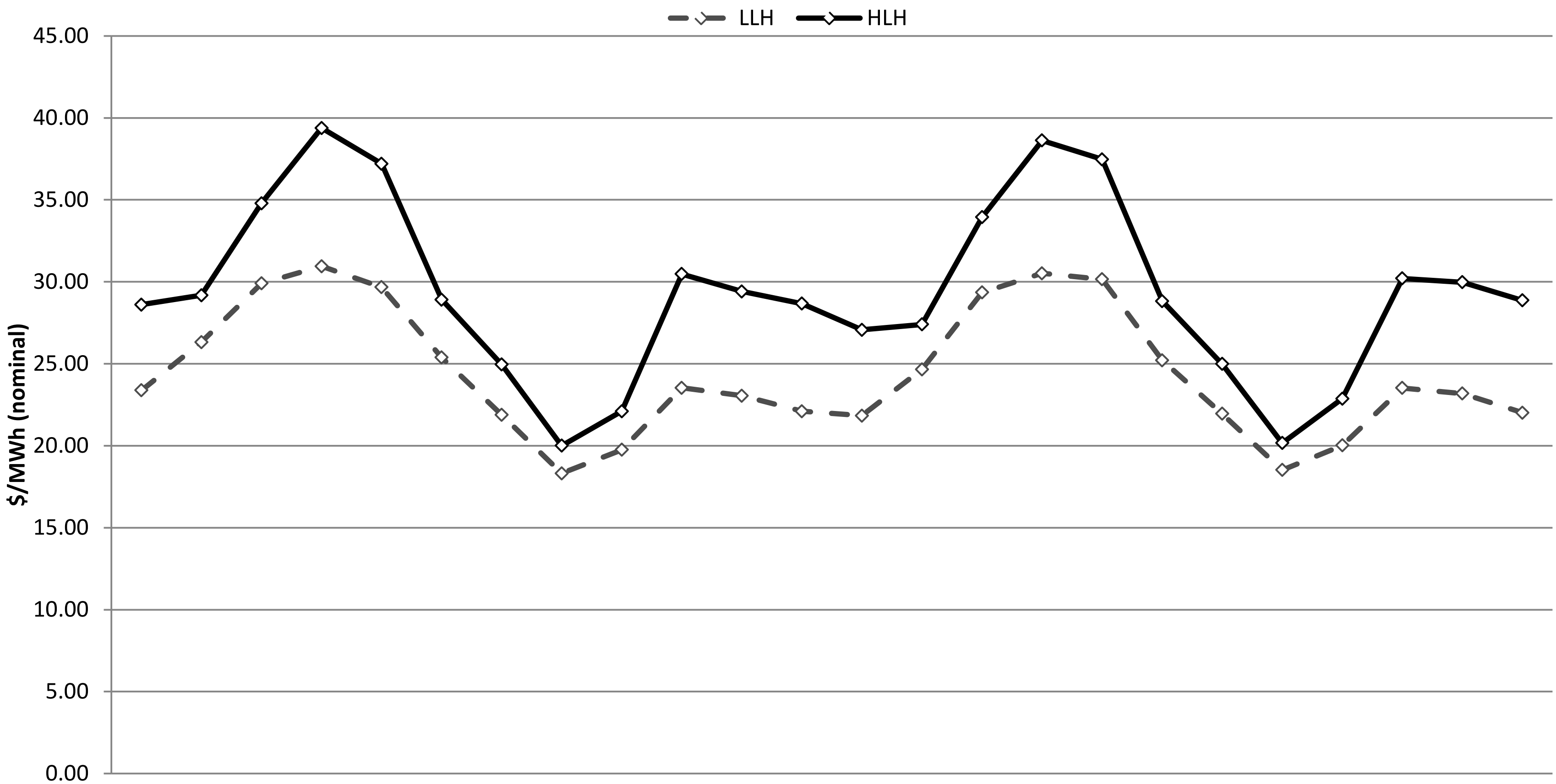


**Figure 8: Monthly Average Mid-C Market Price for FY18/FY19 80 Water Years**




| | Oct 17 | Nov 17 | Dec 17 | Jan 18 | Feb 18 | Mar 18 | Apr 18 | May 18 | Jun 18 | Jul 18 | Aug 18 | Sep 18 | Oct 18 | Nov 18 | Dec 18 | Jan 19 | Feb 19 | Mar 19 | Apr 19 | May 19 | Jun 19 | Jul 19 | Aug 19 | Sep 19 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LLH | 23.25 | 25.55 | 26.98 | 24.32 | 23.93 | 20.93 | 17.55 | 10.85 | 8.32 | 19.39 | 22.59 | 22.21 | 21.72 | 23.94 | 26.23 | 23.57 | 23.95 | 20.66 | 17.53 | 11.66 | 10.31 | 18.72 | 22.64 | 22.17 |
| HLH | 27.55 | 28.16 | 30.76 | 29.80 | 28.60 | 23.94 | 19.81 | 16.48 | 16.80 | 24.96 | 27.93 | 27.93 | 25.93 | 26.39 | 29.80 | 28.80 | 28.48 | 23.56 | 19.53 | 16.78 | 18.62 | 24.35 | 28.29 | 27.96 |

**Figure 9: Monthly Average Mid-C Market Price for FY18/FY19 Critical Water**




| | Oct 17 | Nov 17 | Dec 17 | Jan 18 | Feb 18 | Mar 18 | Apr 18 | May 18 | Jun 18 | Jul 18 | Aug 18 | Sep 18 | Oct 18 | Nov 18 | Dec 18 | Jan 19 | Feb 19 | Mar 19 | Apr 19 | May 19 | Jun 19 | Jul 19 | Aug 19 | Sep 19 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LLH | 23.38 | 26.32 | 29.90 | 30.95 | 29.67 | 25.38 | 21.89 | 18.32 | 19.75 | 23.53 | 23.05 | 22.10 | 21.83 | 24.66 | 29.35 | 30.52 | 30.15 | 25.21 | 21.95 | 18.52 | 20.02 | 23.53 | 23.18 | 22.01 |
| HLH | 28.61 | 29.17 | 34.79 | 39.38 | 37.20 | 28.91 | 24.96 | 20.01 | 22.10 | 30.48 | 29.41 | 28.67 | 27.07 | 27.40 | 33.94 | 38.62 | 37.47 | 28.82 | 24.99 | 20.17 | 22.87 | 30.20 | 29.98 | 28.87 |

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