2018 INTEGRATED RESOURCE PLAN – PROGRESS REPORT

Prepared in collaboration with

THE EnergyAuthority
**Table of Contents**

Executive Summary .................................................................................................................. 3

The District ................................................................................................................................. 3

2018 Integrated Resource Plan Results Summary .................................................................. 3

2018 Refresh Results .................................................................................................................. 6

Section 1: Supply-Demand Overview ...................................................................................... 8

Section 2: Policy & Regulation .................................................................................................. 15

Protect Washington Act (Initiative 1631) ................................................................................ 15

Section 3: Energy Demand ......................................................................................................... 16

Updated Econometric Forecast ................................................................................................. 16

Section 4: Conservation ............................................................................................................. 17

Section 5: Emerging Technologies ........................................................................................... 18

Corporate Renewable Procurement ......................................................................................... 19

Electric Vehicles ....................................................................................................................... 19

Section 6: Energy Supply ........................................................................................................... 20

Economic Screening .................................................................................................................... 21

Levelized Cost of Energy Results .............................................................................................. 21

Section 7: Market Simulation ..................................................................................................... 22

Model Structure ......................................................................................................................... 23

WECC-Wide Forecast .................................................................................................................. 24

Long-Term Fundamental Simulation ........................................................................................... 24

Principal Assumptions ................................................................................................................ 24

WECC Load ................................................................................................................................ 24

Regional Planning Reserve Margins ......................................................................................... 27

WECC Renewable Portfolio Standards ..................................................................................... 28

Natural Gas Price ....................................................................................................................... 28

Carbon Pricing ............................................................................................................................ 29

Capacity Expansion & Retirement ............................................................................................. 31

Power Price Simulation .............................................................................................................. 32

Scenario Analysis ....................................................................................................................... 36

Section 8: Action Plan Updates ................................................................................................. 41
Executive Summary
This is a progress report to the District’s 2016 Integrated Resource Plan. The purpose of this document is to show the District’s current resource requirements outlook and highlight any refinements to the 2016 resource acquisition strategy. The 2016 plan can be viewed on the District’s website.

The District
The District provides electric service to 48,500 residential, commercial, industrial and street lighting customers county wide. The District buys about 90% of its wholesale power from the Bonneville Power Administration. The majority of the BPA power comes from the Federal Columbia River Power System (FCRPS) hydroelectric projects. BPA also sells the output of the Columbia Generating System (nuclear plant) near Richland, WA, and makes miscellaneous energy purchases on the open market, which may include resources other than hydro.

The District owns the 73 megawatt Swift No. 2 Hydroelectric Project located on the North Fork Lewis River in the southeast corner of Cowlitz County. Swift No. 2 provides approximately 5% of the District’s wholesale power needs. The District also receives the output from a number of renewable resources. The District receives 46% of the project output – roughly 94 MW of capacity – from the White Creek Wind Project, 30% of the project output, about 30MW of capacity, of the Harvest Wind Project, and is a small offtaker of the Nine Canyon Wind Project.

The balance of the District’s power requirements are met by purchases from the Mid-Columbia hydro projects owned by Grant County PUD (Priest Rapids and Wanapum).

2018 Integrated Resource Plan Results Summary
In accordance with RCW 19.280.050 the District completed and reported a resource plan based on a thorough examination its 20-year load/resource balance forecast, Washington state renewable portfolio standards, and sophisticated long term wholesale energy price forecasts in 2016. The report anticipated a shortfall in Renewable Portfolio Standard (RPS) compliant generation beginning in 2026 and identified growing potential for winter capacity deficits. The District identified a number of potential resource options for further study, and narrowed the field down to four distinct portfolios:

1) Meet capacity and renewable shortfalls with Market Purchases
2) Build or buy new solar generation located in Eastern Washington or Oregon (the sunny side)
3) Build or buy peaking capacity utilizing reciprocating engine technology
4) Meet capacity and renewable shortfalls with Market Purchases while simultaneously experiencing a loss of an existing renewable resource (Harvest Wind)

Out of the field of potential resource options, these four scenarios were selected for further investigation for various reasons;

1) The District has experience managing resource surpluses and deficits through market activity as a BPA Slice customer, and the deficits identified in the study were not only small relative to the District’s total requirements, but materialized nearly a decade in the future, hence the inherent logic in relying on market based solutions.

2) Solar generation profiles appear to be complimentary to the District’s wind portfolio, which tends to generate more during off peak hours, while solar obviously generates more during the daytime hours. With an anticipated RPS shortage, it made sense to evaluate diversification of RPS resources with solar technology. At the time, solar located in the Eastern portion of WA/OR had a higher anticipated capacity factor, and therefore was the least cost solar option available.

3) Reciprocating (Recip) engine technology is typically dispatched as a peaking resource. Simple cycle Combustion Turbines (CT) also provide the same benefits for slightly lower expected cost, however Recip technology has other fast ramping attributes that the District found appealing, and its leveled cost projection was within $4 per MWh of CT option. Given the forecast of potential winter peak deficits, the District felt it appropriate to analyze the impacts of the addition of a peaking resource to its portfolio.

4) The scenario that evaluated a loss of Harvest Wind was identified as a “stress test” in the 2016 IRP. In reality, Harvest Wind is owned by multiple parties, and at the time, some of the parties were in the process of evaluating asset sale opportunities. Ultimately, nothing materialized, however the District obviously had a need to deeply evaluate the impacts in the case the sale endeavors became serious.

The evaluation methodology was a multi-step process. First, the District had to formulate a long term view of wholesale energy and renewable energy credit prices. The District has exposure to the Mid-C market hub, which in the grander scheme is one of the more liquid trading hubs in North America. This means that within about a 5-year period, the District has high confidence in the prices at which it could transact with counterparties to procure deficit energy or dispose of surplus energy. Forward Price curves, which is the industry term for a long term price forecast, can be extrapolated out for decades, however outside of a 5 year window these prices are more theoretical than transactable. That being the case, the district utilized production cost modeling software (Aurora XMP) to develop a long term price forecast. The District chose to utilize this software package because it is the same package that BPA utilizes for its long term price forecasts, and in general it is a widely utilized program for long term price modeling in the Western Interconnect.

The long term price forecast process is complicated. First, the IRP team needs to gather all available information about potential policy changes in the Western Interconnect (WECC). This includes current and anticipated state level policy for both renewable standards and carbon tax legislation. Next, these requirements are added as an input into the software platform, along with any publicly available
forecasts of generation resource additions or retirements. The software program takes this information to develop a forecast of additional resource additions and retirements. These resources are then added back into the model, which runs, with hourly granularity, for 20 years. The model is a production cost model, meaning that it ensures loads are met by the least cost resource at all times. At any given time, the last resource dispatched to meet the last MW of load is considered the “marginal resource.” In other words, market price is determined by the generation cost of the last resource required to meet the last MW of load.

The long term price forecast is just one possible future, colloquially referred to as a “point-forecast.” In order to evaluate the risk of various resource strategies, the IRP team must derive a range of prices where the point-forecast is the average outcome, but ultimately only one of infinite possible futures. In order to model this uncertainty, the District employed sophisticated analytics that models historical volatility and various price relationships (such as load, NW hydro generation, natural gas price, etc.) to create a realistic price distribution around the Aurora-derived long term price forecast.

With a long term price distribution, the District then applies these prices, both power and gas, to a long term model of its portfolio under the four scenarios discussed earlier. Ultimately the model output is not only an expected cost of a specific resource strategy, but also a range of costs which can be analyzed to understand the relative risk of each evaluated strategy (Figure 1).

**Figure 1: Generation Resource Alternatives Cost and Risk Simulation**

The Y axis (Standard Deviation) represents the risk associated with each strategy plotted on the chart. The X axis shows the calculated cost per MWh of load served under each strategy. The various resource strategies were all relatively similar in cost and risk. The deviations look larger on the plot due to the tight ranges employed on both axes. The “Status Quo” portfolio represents the option where the District meets both its projected RPS and capacity deficits with wholesale market purchases. Ultimately, the District identified this option as the preferred path in 2016 for multiple reasons:
1) The capacity deficits the District identified were very small and based on experience manageable through a prudent risk management program, which the District has successfully employed for years.

2) The alternative resources plans were more expensive, with solar being both more expensive and riskier, while the reciprocating engine portfolio was more expensive while slightly less risky.

3) The IRP report highlighted precipitous reductions in cost curves for numerous existing and emerging technologies. Given uncertainty around potential future resource costs, it made little sense to declare a specific resource the preferred portfolio option given the time horizon of the study and anticipated needs.

In summary the 2016 plan deeply analyzed risk, price projections, and forecasted portfolio needs over a 20-year horizon and ultimately concluded that the best path forward for the District’s customers was to diligently manage emerging needs through careful monitoring of market conditions and a combination of opportunistic and systematic wholesale market transactions executed to fit specifically identified areas of need. Although a Renewable Portfolio shortage appeared in 2026, there was no urgency to initiate any sort of official procurement process given the time horizon, falling costs of technology, and uncertainty around the underlying load forecast itself. Add in uncertainty around numerous policy initiatives such as Carbon legislation and even the State’s RPS mandate, a disciplined, piecewise, and targeted approach was the obvious preference.

2018 Refresh Results
Much of the processes outlined above were completely revisited in the 2018 plan. The Aurora price model was updated with the latest policy, retirement, buildout, and gas price forecasts. The District’s long term portfolio, including long term load forecast, resource capability, and contract status assumptions were revisited and revised. This reassessment produced numerous results that significantly deviated from the assumptions that were carefully developed just two years ago.

First, one of the District’s primary customers has reduced its long term load forecast by more than 100aMW. From a planning perspective there is enough uncertainty around timing and magnitude of this industrial load that the IRP staff decided to keep the reduction in the long term plan.

Second, the District recently determined that it would forego some of the energy made available under its agreement with White Creek Wind. This decision has slightly decreased the annual aMW volumes associated with this resource. A more impactful assumption change around White Creek is that the District has decided to remove the resource from its portfolio once the original contract expires for planning purposes. This does not preclude the District from negotiating an extension, it simply highlights the fact that there may be other more cost effective alternatives in the future that better fit the District’s needs. By acknowledging this through removal from the long term portfolio, it puts this item on the proverbial radar and highlights it for further analysis.

Third, and in the long term it is the most impactful, is the removal of BPA Power Supply from the District’s resource portfolio beginning in October 2028. In the 2016 study, the District assumed that BPA supply would continue to meet the District’s needs beyond 2028. Soon after the 2016 IRP was
completed, BPA began engagement in regional discussions of its post 2028 plans, including initial price forecasts for its preference power product. On the surface, BPA’s price forecast is not competitive with alternatives. At approximately $42/MWh, the 2028 price BPA shared was about $10/MWh above long term wholesale market price projections. The District can no longer simply assume that it will continue to purchase BPA power to meet 90% of its needs without deeper evaluation of alternatives. By removing BPA from the portfolio assumptions now, the District is highlighting this fact, and highlighting the ongoing need to be fully engaged in not only the BPA ratemaking and product design process, but in discussions with potential alternative suppliers and in evaluation of potential self-supply opportunities. This is by no means as simple as the math above suggests. Rather than declaring a post-BPA strategy today in this document, the IRP staff instead seeks to highlight some of the complexities surrounding this decision and to identify the developments it must follow in order to make a decision that is the best for its customers.

Fourth, and last, is the updated price forecast. In 2016, the IRP staff used a combination of forward natural gas price curves and fundamental analysis collated from 3rd party analysts to develop an NG price assumption to feed its long term price model. The 3rd party analyst assumptions proved to be wildly optimistic, projecting gas prices that today seem unreasonably high. Other inputs, particularly policy assumptions, changed as well but the biggest driver in the change in our price forecast is that instead of utilizing any fundamental analysis, we simply used the long term forward market price for NG. This change in approach resulted in a significantly lower forward price assumption than the one developed only two years ago. Ultimately, this new lower price forecast is in line with industry consensus. NG production continues to break records. With gas being the primary fuel for marginal resources throughout the country, high production and low input prices should continue to lead to low long term power prices.

In 2016 the District forecasted higher loads, showed a renewable deficit, and assumed it would purchase BPA supply in perpetuity. Based on a thorough analysis, we concluded that utilizing the wholesale market was the best path forward to meet incremental needs. In 2018 our load forecast is more than 100 aMW lower, we are no longer showing a renewable deficit within the 10-year window examined, and our market price forecast is substantially lower than it was 2 years ago. These are significant changes and highlight the problem with making definitive resource decisions today for potential needs that materialize a decade from now. For these reasons, the District reaffirms its strategy of relying on the wholesale market to meet its incremental needs.

The BPA Power Supply contract sunsets in October 2028. This represents the single biggest priority from a planning perspective for the District. This study does not recommend a definitive plan to address how the District will supply its obligations afterwards, instead, it highlights the types of things we must consider as policy, price, market conditions, and other factors become more clear as we move through time.

The body of this document is a detailed narrative of the inputs the District has refreshed over the past two years, including discussion of how assumptions have evolved. In addition, we have continued to
monitor developments in new technologies, prices and opportunities that may impact the District, its load, and its supply options in the future and have documented many of the major items of interest.

Section 1: Supply-Demand Overview
Figure 2 displays the District’s forecasted load-resource balance with existing resources and contracts. The chart below assumes “firm” (i.e. critical) generation capability for all hydro, including Slice. Critical hydro generation is based on 1937 water conditions, the lowest water year in the official 70-year record dating back to 1929. Under today’s system, a repeat of 1937 conditions would yield an annual generation value of 6,945 aMW for the FCRPS. The District’s share would be roughly equal to 417 aMW. Under this conservative planning scenario, the District is expected to be surplus energy on an average annual basis. Average hydrological conditions would produce an average annual generation value of about 8,900 aMW. The District’s share would be 533 aMW. On an energy basis under critical water, the utility is projected to have sufficient resources to meet its projected needs through 2028, the end of the study period.

Figure 3 is the District’s critical water annual net position. The District’s contract with the White Creek Wind project ends in late 2027 and the District’s Slice/Block contract ends in October 2028, exclusion of
these resources account for the decrease in supply side resources beginning 2028. While the net position fluctuates by season, month, day, and hour, the District, on average carries an energy surplus until October 2028.

**Figure 3: Net Position Assuming Critical Hydro with No Resource Additions**

![Net Position Graph](image)

Compared to the 2016 IRP, there are a handful of significant changes to both the District’s supply and demand projections (Figure 4).
The revised resource plan projects a significant shift in future load projections relative to the 2016 IRP. The change is driven by an approximate 100aMW demand reduction in the industrial sector.

The District’s supply portfolio is also impacted as a result of the reduced load forecast. Since BPA power is allocated based on the District’s annual load forecast, a reduction in load results in a similar reduction of BPA supply. This change is reflected in the District’s Block allocation (Figure 5).
A second reduction in BPA Block power occurs in 2028. It is due to the uncertainty of the District’s power supply once the BPA contract ends at the end of September 2028. For this study, the IRP team assumed the District would stop receiving BPA power at the end of the current contract. Because the contract ends effective October 2028, the power supply resource reduction related to BPA block for the 2028 calendar year is about 40aMW. Beginning calendar year 2029, the District is not currently contractually obligated to purchase BPA power supply.

Because the BPA Slice allocation is a fixed percentage as defined in the BPA contract, it is not affected by fluctuations in load. Thus, the BPA Slice resource changes only in 2028 (Figure 6).
Figure 6: 2016 vs. 2018 District Share of BPA Slice Resource

It is a contrast to the 2016 study in which the IRP team assumed that the District would renew its contract with BPA, and effectively obtain energy from BPA in perpetuity. After the 2016 IRP was completed, BPA began regional discussions regarding their Power Supply cost projections when their current Regional Dialogue contract expires in October 2028. BPA's initial cost projections are currently significantly above our projections of wholesale market prices in 2029 and beyond. Given this, the IRP team felt it prudent to exclude the BPA resource beginning October 2028 to flag this important subject for further analysis. There are many factors that must be considered in the BPA discussion, and we will explore these factors in progressively greater detail as time moves on. The District anticipates BPA will begin contract discussions with its customers within the next few years as it will likely take a number of years to conclude.

In addition to uncertainty around the post 2028 BPA contract, there is a second contributing factor to the District’s energy deficit that appears in 2028 is due to the conclusion of the White Creek Wind contract. Cowlitz PUD has a right to purchase the asset at the end of its contract; prior studies assumed that the District would elect to exercise this option. Due to changes in both supply and demand dynamics, that assumption has changed and the District will be considering alternatives.

In addition to the pending conclusion of the White Creek Purchase obligation, there has also been a reduction in the annual delivery volume forecast. Energy received from White Creek is priced in annual energy tiers. The District is allocated a fixed, annual quantity of Tier 1 energy at one pricing level, while Tier 2 energy is all other energy in excess of Tier 1 priced at another level. A scheduled increase in the cost of Tier 2 power effective in 2018 has caused the District to elect to forgo receiving energy deliveries
from the resource beyond the Tier 1 quantity, which will typically happen by December of each year (Figure 7).

Figure 7: White Creek Wind Energy Contribution Prior to Contract Expiration

The contribution from the District’s other non-Federal resources (Swift, Harvest Wind, Nine Canyon, Wanapum/Priest Rapids) remain effectively unchanged.

Figure 8 illustrates the District’s RPS requirements against existing REC generating resources. Since the inception of the RPS program, the District possessed sufficient REC generating resources to fulfill its RPS obligations. Under the current load forecast, the District is expected to continue to be able to meet its regulatory obligations. After the RPS requirement increases from 9 percent to 15 percent in 2020, the District will be able to rely on its resources and REC bank (prior year RECs), to fulfill I-937 compliance.

The District has a number of REC eligible generating resources from wind, hydro, and biomass resources. The White Creek, Harvest, and Nine Canyon projects are wind resources; the White Creek contract ends towards the end of 2027 at which point the District will need to decide whether to extend the term, or not. While the Wanapum and Priest Rapids large hydro dams are not typically REC eligible generators, regulations state that incremental increases in generating capacity resulting from efficiency improvements produce eligible RECs. This provision is the reason for the small amount of RECs received from these projects.

Non-District owned resources also contribute to fulfill the District’s RPS requirements, as several companies located within the District utilize biomass fuel in their generators to supply a portion of their own power needs and these resources generate I-937 eligible RECs.
The District expects to carry a REC surplus through the whole study period. This is a notable change from the 2016 IRP that forecasted a REC deficit beginning 2026 (Figure 9). REC supply remained stable through this period, with the primary driver being the reduction in loads, which in turn reduces the RPS obligation.
In summary, the District’s 2018 update to its projected energy demand and REC positions show the District is generally surplus through the study period. The exception is 2028 when the BPA and White Creek Wind contracts expire. The updated 2018 analysis assumes no renewal of these contracts to draw attention to these important resource decisions looming in the future.

**Section 2: Policy & Regulation**

Energy policy is currently an active topic both on the state and federal level. Since the 2016 IRP on the state-level, a Thurston County Superior Court orally invalidated the Clean Air Rule and the I-732 carbon tax ballot initiative failed. Stakeholders since introduced a replacement initiative, I-1631, which is on the ballot in the upcoming election. On the federal level, the US EPA proposed formal repeal of the Clean Power Plan, FERC is reviewing its PURPA rules, and the Federal Investment Tax Credit and Production Tax Credit were generally extended through 2022.

Except for I-1631, which we will address here, refer to the 2016 IRP for further discussion on the aforementioned policies.

**Protect Washington Act (Initiative 1631)**

On the upcoming November 2018 ballot is Initiative 1631, which would create a fee on carbon emissions, including those from the electricity generated by fossil fuels. The Initiative would cover both electricity generated in the State of Washington and that which is imported into the State. The fee would start in 2020 at $15 per metric ton of carbon dioxide emissions, increasing at an annual rate of $2 per metric ton plus inflation per year. The annual increases would continue until the State reaches its stated 2035 carbon reduction goal of 20 million metric tons relative to the 2018 baseline and on a trajectory to meet its 2050 carbon reduction goal of 50 million metric tons relative to 2018. Receipts from the fee would be deposited in a “Clean Up Pollution Fund” and disbursed to communities such that 70 percent of the funds would go towards clean air and clean energy investments, 25 percent towards clean water and clean forest investments, and 5 percent towards healthy community investments. The District would also be eligible to claim a majority of the carbon fee it contributes to the fund.

(6)(a) A qualifying light and power business or gas distribution business may claim credits for up to one hundred percent of the pollution fees for which it is liable under this chapter. Credits may be authorized for, and in advance of, investment in programs, activities, or projects consistent with a clean energy investment plan that has been approved by the utilities and transportation commission, for investor-owned utilities and gas distribution businesses, or the department of commerce, for consumer-owned utilities.

The District would be required to invest proceeds from the fund on clean energy investments, pending approval from the Washington State Department of Commerce. Regardless of the result at the ballot box, it seems likely that some form of a carbon tax will become Washington State law in the near future and will impact the energy sector.
Section 3: Energy Demand

Updated Econometric Forecast
The District refreshes its 20-year forecast of energy sales, customer counts, and peak demand on an annual basis (Figure 10). The forecast uses an econometric model that measures the relationship between key economic factors and demand for energy. The District uses macroeconomic forecasts as an input to the model to create a long term demand forecast. The result is the foundation of the District’s resource planning activities and a key input to its budget analysis.

Figure 10: 2018 Load Forecast

This IRP projects a significant shift in future load projections relative to the 2016 IRP and historical actuals (Figure 11). Because a handful of industrial customers represent a majority of the District’s load, a change in production plans of a single customer can have a dramatic effect on overall District-wide consumption. While non-industrial loads are expected to be lower than anticipated as compared to the 2016 forecast, the change is driven by an approximately 100aMW demand reduction in the industrial sector. The forecast includes the impact of energy efficiency achievements. For the next 10 years, the District forecasts an annual average growth rate of 0.024 percent. Conservation efforts, along with strides in technology are increasing economic output, while decreasing overall energy consumption. This phenomenon is not limited to Cowlitz PUD; it is a trend widely observed throughout the country.
Section 4: Conservation
The District continues to actively pursue conservation opportunities within its service territory much as it has for the last 37 years. In this time period, the District’s conservation programs have achieved an accumulated savings of over 28 average megawatts.

Efficiency is increasing across all household appliances. Electric furnaces that utilize resistance heating, still commonly found in homes across Washington State, have a coefficient of performance (COP) of 1. For each unit of energy input, a single unit of heat is output. Heat pump systems, on the other hand, have COPs ranging between 2 and 4, meaning that they are between 2 and 4 times more efficient than electric furnaces. Heat pump technology continues to improve, as COPs have continued to increase in recent years.

Heating/cooling (47%), water heating (14%), and lighting (12%) cumulatively make up roughly 73 percent of home energy consumption, excluding transportation. LED technology that can reduce lighting loads by greater than 80 percent and air conditioning loads by 50 to 75 percent is commercially available and viable today. There will be ongoing impacts to home energy consumption as more of the less efficient appliances are replaced with newer technology.

A more detailed assessment can be found in the District’s 10-year Conservation Potential Assessment available on the District’s website.
Section 5: Emerging Technologies

Technology is rapidly evolving which translates into rapid change for the utility industry. Though not widespread in the region, solar technology is rapidly coming down in price, and costs have roughly halved since the 2016 IRP as solar panel and manufacturing efficiencies increase, while operation and maintenance costs concurrently decrease with more experience. Solar generators continue to be added at a rapid pace (Figure 12).

Figure 12: Cumulative Annual US Solar Generation Capacity

Wind energy is following a similar path as manufacturers increase blade size and design power plant sites to maximize the resource. Nearly half of all utility scale capacity additions in 2017 came from renewable resources and that is a decrease on a percentage basis from 2014-2016 (Figure 13).
Corporate Renewable Procurement

Introducing additional uncertainty in the generation landscape is what actions corporations will embark upon to meet their sustainability goals. In 2016, approximately 70 companies committed to becoming 100 percent renewable, including several Fortune 50 companies. The most current list has 135 companies committing to that goal.

An increasing trend for Corporations, such as these that have a choice, is to focus on building new renewable energy projects to meet their needs, rather than relying on the procurement of existing resources. The list of these commitments are growing – and it may not be all inclusive. Some companies may be pursuing this goal independent of any commitments. The challenge to resource planning is that the additional generation may not be built out of need or even economics; 100 percent renewable energy is now part of the corporate strategy. In other words, power resource planners have little understanding as to when and how much of this new generation is slated to come online.

The continued addition of zero-marginal cost resources adds downward pressure on market prices, as these resources replace conventional generators.

Electric Vehicles

Cumulative EV sales as of the end of 2017 totaled about 1 million vehicles, less than 0.5 percent of the total passenger vehicle fleet.¹ Most forecasts, however, project EV adoption to follow along an “S-curve” trajectory, which is flat in the beginning and steeper in the middle. Following the theory, US adoption is currently at the beginning of the S-curve, and within the next decade will move towards a steeper part of the curve when EVs are forecasted to comprise over 10 percent of the vehicle fleet by 2030.² Norway is already leading the charge, where EVs made up 52 percent of new vehicle sales in

---

² ibid
December 2017. This is a large jump from 2016, when the EV market share was about 23 percent. Norway incentivizes the adoption of EVs by providing generous subsidies, along with already high gasoline prices which tilt the economics away from internal combustion engine vehicles.

The impact of EV adoption on District loads is currently minimal and is not a variable in the long-term load forecast. Loads will increase proportionally with EV penetration. In the 2016 IRP, EV adoption was not an influential variable in the District’s load forecast and it is still not. However, the forecast of total EV inventory by 2030 has more than doubled since the prior study (Figure 14). The District’s share of EVs is still not sufficient to materially impact its load. However, if forecasts continue to see drastic upward revisions, EVs will factor into District loads sooner rather than later.

Figure 14: Evolution of EV Inventory Forecast

**Section 6: Energy Supply**

The District sources its power requirements through purchases from BPA as well as from several non-federal sources of power. Cowlitz PUD’s generation mix is made up of hydroelectric, wind, and nuclear generation resources. The hydroelectric resources, in descending order of electricity generation capacity, include a share of the Federal Columbia River Power System (FCRPS) through the Slice/Block product, the Swift No. 2 hydroelectric project, and a share of the Wanapum and Priest Rapids Hydroelectric Projects. Wind resources include the White Creek, Harvest, and Nine Canyon wind

---

3 Lambert, Fred. “Electric cars reach new 52% market share record in Norway thanks to Tesla’s record deliveries.” Electrek. 03 January 2018.
projects. Cowlitz PUD also receives a share of the output from the Columbia Generation Station nuclear reactor as a part of the Slice/Block contract. Bonneville Power Administration (BPA) is the marketer and distributor of power generation provided by the FCRPS and Columbia Generation Station. BPA resources include the 31 dams of the FCRPS and Columbia Generation Station.

The changes in the District’s energy supply portfolio relative to the 2016 IRP was discussed in Section 1: Supply-Demand Overview.

**Economic Screening**

The 2016 IRP utilized a complex suite of quantitative models to derive the best portfolios for the District. This study will not go into as much detail, but still aims to provide guidance as to what resources are most economical at this time. Changes in labor cost, raw materials cost and market fundamentals can cause certain technology types to become relatively more or less competitive. The goal of this section is to aggregate the newest cost information for each feasible generation type and determine which types are currently most competitive. The results will help inform the District’s future resource acquisition strategy.

**Levelized Cost of Energy**

A useful tool for ranking resource types by cost effectiveness is calculating the levelized life cycle cost of energy production. This approach allows for an “apples to apples” comparison of plants with different operating lives, capital costs and operating economics.

**Results**

The results from the levelized cost calculation are displayed in Figure 15. The least cost renewable is wind energy located in Central Washington. The least-cost non-renewable generation type is combined cycle natural gas.

Combined cycle costs are low as natural gas is low priced and forward price expectations are that prices will remain low for the foreseeable future. The price environment changed significantly since the prior study. Henry Hub natural gas price forecast in the 2016 IRP reached over $5/MMBTU in 2028. Current forecasts project 2028 prices to be around $2.50/MMBTU. However, thermal units are running at lower capacity factors today due to the influx of renewable energy amid stagnant loads. Despite lower fuel costs, lower overall capacity factors are driving up the levelized cost of combined cycle units over their economic life.

Renewable technology cost forecasts have declined since the prior study. As technology continues to evolve, the generators become more efficient at converting wind or sunlight to energy, thus increasing overall capacity factors. In the case of wind energy, the efficiency gains are primarily realized from longer blade lengths, but also incremental improvements in design and siting to maximize the resource potential. Capital costs are also lower than previously forecast, resulting in lower energy production costs.
Section 7: Market Simulation

The electricity price simulation is created by several fundamental models working in concert. Figure 16 provides an overview of the process used to create the price simulation. The progression can be broken down into three principal phases. In the first phase, fundamental and legislative factors were modeled and integrated, including carbon penalty assumptions, load forecasts, and regional renewable portfolio standards. The second part of the study uses the inputs from the first step to run a capacity expansion analysis. In this phase, market prices are simulated for all of the Western Interconnect utilizing a production cost methodology. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 10-year time horizon. In the final phase, the modified supply stack is integrated back into a stochastic simulation of price, fuel and hydro variables. This section will describe the price simulation in further detail.
Model Structure

The main tool used to determine the long-term market environment is Aurora. Developed by EPIS, Inc., Aurora simulates the supply and demand fundamentals of the physical power market, and ultimately produces a long-term power price forecast. Using factors such as the economic and performance characteristics of supply resources, regional demand, and zonal transmission constraints, Aurora simulates the WECC system to determine an adequate generation portfolio, constrained by the limitations of the transmission network, that work together to serve load. The model simulates resource dispatch which is used to create long-term price and capacity expansion forecasts. The software includes a database containing information on over 13,600 generating units, fuel prices, and demand forecasts for 115 market areas in the United States.

The District utilized Aurora for four main purposes:

1. To determine a long-term deterministic view of resource additions
2. Establish an expected long-term forecast price
3. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions

The District created or utilized reputable third party forecasts of key variables, such as regional load growth rates and planning reserve margins, natural gas prices, hydro generation, and carbon prices. Renewable resource additions were set to correspond to the regional load growth and renewable portfolio standard set by each state. Using a recursive-optimization process, Aurora determines an economically optimal resource expansion path within the given constraints. Once long-term capacity
expansion results were created, they were input into a model that utilizes various stochastic inputs: natural gas prices, hydro generation, and renewables (wind and solar) to stochastically generate a long-term price forecast for the Mid-Columbia (Mid-C) region.

**WECC-Wide Forecast**

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which encompasses the 14 western-most states in the U.S., parts of Northern Mexico and Baja California, as well as Alberta and British Columbia. The WECC region is the most geographically diverse of the eight Regional Entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). Aurora was used to model numerous zones within the Western Interconnect based on geographic, load and transmission constraints. The analysis focuses mainly on the Northwest region, specifically Oregon, Washington and Idaho. Even though the study forecast focuses on the Mid-C electricity market, it is important to model the entire region because fundamentals in other parts of the WECC exert a strong influence on the Pacific Northwest market. Because of the ability to import electricity from or export to other regions, the generation and load profiles of another region can have a significant impact on Mid-C power prices. As such, to create a credible Mid-C forecast, it is imperative that the economics of the entire Western Interconnect are captured.

**Long-Term Fundamental Simulation**

A vital part of the long-term market simulation is the capacity expansion analysis. The study utilized Aurora to determine what types of power plants will likely be added in the WECC over the next 10 years, given our current expectations of future load growth, natural gas prices, and regulatory environment. To arrive at an answer requires an iterative process. In the first step, Aurora was programmed to run a 10-year dispatch study assuming that no new plants are built in the WECC. In the second step, Aurora progressively adds resources to meet expected load growth and renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price.

**Principal Assumptions**

This section reviews the key assumptions that were used in the capacity expansion.

**WECC Load**

Aurora’s default demand escalation forecasts for zones in the WECC region are based on WECC’s Transmission Expansion Policy and Procedure Study Report\(^6\) and are provided in the Aurora database. However, based on recent observed retail load in the WECC and using the most recent forecast from the Northwest Power and Conservation Council’s Seventh Power Plan, load is expected to decrease in the Pacific Northwest region, with an annual average of -0.67% growth.\(^7\) Increases in energy efficiency, behind the meter generation, slower economic growth, and decreased population growth have contributed to

---

\(^6\) [https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_StudyReport_draft.pdf](https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_StudyReport_draft.pdf)

\(^7\) [https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf](https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf)
flat or negative load growth when compared to the historical average. Figure 17 illustrates the clear flattening/declining trend to retail loads in nearly every state in the WECC over the past two decades.\footnote{https://www.eia.gov/electricity/data/state/sales_annual.xlsx}

Figure 17: Historical WECC Retail Loads

Because of this trend, the IRP team applied NWPC\textsc{c}'s regional annual average load growth of -0.67\% to the entire WECC for the Base Case of this study. For sensitivity studies, the lowest and highest load forecast projections from the Northwest Power and Conservation Council were used (Figure 18).
Figure 18: NWPPC Load Projections

<table>
<thead>
<tr>
<th>Year</th>
<th>Lowest</th>
<th>Median</th>
<th>Highest</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>18,422</td>
<td>19,873</td>
<td>21,315</td>
</tr>
<tr>
<td>2020</td>
<td>18,344</td>
<td>19,754</td>
<td>21,230</td>
</tr>
<tr>
<td>2021</td>
<td>17,726</td>
<td>19,605</td>
<td>21,447</td>
</tr>
<tr>
<td>2022</td>
<td>17,253</td>
<td>19,464</td>
<td>21,601</td>
</tr>
<tr>
<td>2023</td>
<td>17,010</td>
<td>19,320</td>
<td>21,736</td>
</tr>
<tr>
<td>2024</td>
<td>16,543</td>
<td>19,157</td>
<td>21,766</td>
</tr>
<tr>
<td>2025</td>
<td>16,513</td>
<td>19,049</td>
<td>21,790</td>
</tr>
<tr>
<td>2026</td>
<td>15,644</td>
<td>18,881</td>
<td>21,648</td>
</tr>
<tr>
<td>2027</td>
<td>15,630</td>
<td>18,805</td>
<td>21,909</td>
</tr>
<tr>
<td>2028</td>
<td>15,203</td>
<td>18,699</td>
<td>21,981</td>
</tr>
</tbody>
</table>

2019-2028 Average Annual Growth rate: -2.11% -0.67% 0.34%

The regional load forecast assumption used in the IRP team’s production cost modeling also saw a significant decline since the prior study. In 2016, the regional load growth assumption averaged between 0.4% and 0.6% per year through 2036 (Figure 19).

Figure 19: 2016 Regional Load Growth Forecast

These trends are being observed nationwide. A century-long trend of steady load growth came to a halt early in the century. Electricity consumption nationwide has been stagnant for the better part of a decade now (Figure 20).
Regional Planning Reserve Margins

In order to ensure there will be sufficient generating capacity to meet demand in case of generator outages or demand spikes, a certain amount of generating reserve capacity is built into the market. These operating reserves are either extra generating capacity at already operating plants, or fast-start generators, usually natural gas fired, which can start-up and reach capacity within a short amount of time.

Planning reserve margins are a long-term measurement of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The planning reserve margin is an important metric used to determine the amount of new generation capacity that will need to be built in the near future. For the capacity expansion analysis, the District used the planning reserve margins set by the North American Electric Reliability Corporation (NERC), in their 2017 Long-term Reliability Assessment (Figure 21).9

Figure 21: WECC Regional Planning Reserve Margins

<table>
<thead>
<tr>
<th>Assessment Area / Interconnection</th>
<th>2018 Reference Margin Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>WECC-AB</td>
<td>11.03%</td>
</tr>
<tr>
<td>WECC-BC</td>
<td>12.10%</td>
</tr>
<tr>
<td>WECC-CAMX</td>
<td>16.14%</td>
</tr>
<tr>
<td>WECC-NWPP-US</td>
<td>16.38%</td>
</tr>
<tr>
<td>WECC-RMRG</td>
<td>14.17%</td>
</tr>
<tr>
<td>WECC-SRSG</td>
<td>15.18%</td>
</tr>
</tbody>
</table>

**WECC Renewable Portfolio Standards**

Renewable portfolio standards (RPS) are requirements, set at the state level, that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. There are currently no federally mandated RPS requirements; states have set their own based on their particular environmental and economic needs (Figure 22).

*Figure 22: WECC RPS Assumptions by State*

Currently 30 out of 50 US states have RPS requirements, including all WECC states except for Idaho and Wyoming. Utah has voluntary RPS guidelines, which were not included in this analysis. California has a higher RPS requirement at 50% by 2030, and Oregon has a 50% requirement for its IOUs by 2040. There is wide variability in the requirements between states in the region, which could have a sizeable effect on electricity pricing within the region. There is a long-term minimum constraint functionality built into the Aurora long-term capacity expansion model. This enables more consistent economic evaluation of different renewable resource additions.

**Natural Gas Price**

Natural gas prices are a key factor in the market simulation. It is challenging to forecast natural gas prices in the future, as the prices are inherently volatile and market dynamics are constantly changing. Figure 23 displays Henry Hub forward pricing data from the New York Mercantile Exchange (NYMEX) through the year 2028. The 2016 IRP used a blend of NYMEX futures contract pricing for the near term and gradually transitioning to a long-term price forecast sourced from a reputable energy research firm. The rationale behind blending the two forecasts was that near-term NYMEX pricing reflects actual trading activity and should encompass all the collective information of the market. In short, it represents the most well-
informed, consensus gauge of the value of the commodity. Outside of the short-term, though, trading activity is limited and accurate pricing ceases to exist beyond a 10-year outlook. The long-term forecast incorporates the fundamental factors of supply, demand, and variables that can cause those to change to develop a forecast.

The IRP team decided to use only the NYMEX forecast for this year’s study for two reasons. First, NYMEX prices are available through the entire shortened study period of 10 years. Second, while research firms rigorously analyze the market to determine their forecast, it reflects a proprietary methodology which is necessarily opaque. It is impossible to reverse engineer a third party forecast based on limited data to validate inputs. The same can be said for market prices; however, NYMEX pricing reflects the opinions of not just a single firm, but of all market participants. Short of developing a separate natural gas price forecast, the IRP team believes NYMEX prices are the best representation of the expected future price of natural gas.

Since 2016, natural gas price forecasts have seen a significant flattening in the outer years, with less contango in the curve, and gas prices are expected to remain at levels close to today’s for the foreseeable future (Figure 23).

**Figure 23: 2016 vs. 2018 Natural Gas Price Forecast**

- **Carbon Pricing**

There is a high level of uncertainty regarding the regulation of Carbon Dioxide (CO2) emissions, as well as the structure and creation of carbon trading markets. Currently in the Western United States, the only state that has a carbon emissions trading market is California, as part of the Western Climate Initiative in partnership with the provinces of British Columbia, Manitoba, Quebec and Ontario.
Although Washington State does not have a carbon trading market, there has been a push in recent years to set one up. For example, the Clean Air Rule ("CAR") went into effect in 2016; this rule, however, was challenged in court and eventually ruled unconstitutional. In addition, a carbon tax initiative failed in 2016. However, a new carbon initiative is on the Washington ballot for the fall of 2018, and suggests a carbon tax in the future is likely. The base case assumes the pricing scheme of this 2018 initiative, I-1631, which starts at $15 per metric ton of carbon in 2020 and escalates at $2 plus inflation each year thereafter.

There has also been a significant push in Oregon to introduce carbon legislation, including a cap-and-trade proposal that would link its program to California’s. As such, we modeled Oregon as having a carbon penalty equal to California’s, starting in 2021. North of the border, British Columbia and Alberta already have carbon taxes in place, which are included in the market simulation (Figure 24).

Figure 24: Carbon Penalty Assumptions in WA, CA, BC, and AB
Capacity Expansion & Retirement
The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, hydro, geothermal, and biomass. The District input economic assumptions for each of these resources such as capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal efficiency), and capacity factor. Based on the parameters outlined above, Figure 25 illustrates the expected new resource expansion and retirement through 2028 throughout the entire Western Interconnect region.

RPS requirements are one of the main drivers of new resource expansion over the next decade. These renewable resources, particularly solar, make up the majority of capacity additions over the study period. A significant contributor to solar economics is the recent extension of the Investment Tax Credit (ITC). Significant solar generation expansion is expected through 2021, after which the ITC drops to 10 percent for commercial and utility projects and zero for residential projects (Figure 25).

Figure 25: Forecasted WECC Generation Capacity Additions through 2028

This is a dramatic shift from the 2016 study, in which the model projected significant additions in thermal generation capacity, with renewable resources built to meet RPS targets (Figure 26).
Both studies project coal output to decline substantially throughout the WECC. By 2028, more than 16,000 MW of coal capacity will be retired. Nuclear output will decline as aging units are taken off-line, and hydro output will stay the same. Future additions are expected to mainly be renewables to meet RPS mandates, with solar the preferred option for the first few years and wind the preferred option for the last years of the study period.

**Power Price Simulation**

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained. Figure 27 displays the expected Mid-C power prices from the long-term capacity expansion run.
Many of the modeling inputs changed between the 2016 and 2018 studies; however, the one with the most influence on power prices is natural gas. When comparing the results between the studies, the price levels of the 2018 forecast are much lower than that from the 2016 study (Figure 28).

Within the past couple of years, there has been a dramatic shift in the relationship between HLH and LLH Mid-Columbia heat rates and power prices. Starting as early as 2020 for lower demand periods, LLH heat rates and power prices are higher than the valley hours of the HLH heat rates and power prices. By the
end of the study, LLH heat rates and power prices are higher than the valley hours of the HLH heat rates and power prices for most time periods throughout the study period (Figure 29). This is a notable change for the Northwest, and is attributable to decreasing loads, low natural gas prices, and the continued increase in solar generation through the entire WECC region.

Figure 30, Figure 31, and Figure 32 below are the average hourly profile of Mid-Columbia power prices for the months of April, August, and December in the years 2020, 2024, and 2028. As can be seen, there is an increase in the duck-curve phenomenon as we move through time and more solar generation comes online, particularly in the evening ramp.

Figure 29: Mid-C HLH/LLH Spread
Figure 30: Mid-C Average Hourly Price Profile for April 2020, 2024, and 2028

Figure 31: Mid-C Average Hourly Price Profile for August 2020, 2024, and 2028
### Scenario Analysis

In addition to the above Base Case scenario, four other alternative hypothetical scenarios were considered. These were separate model runs intended to stress two of the key assumptions that went into the market simulation, and based on the IRP team’s judgment, could potentially change in the near future. These changes reflect differences in key underlying assumptions in the market simulation model that directly affect the expected case, whereas the stochastic simulations provide a distribution around the expected case. The goal of the scenario analysis is to project a range of outcomes contingent upon changes in key underlying assumptions that are included in the market simulation. These four alternative scenarios include:

1) **Low Load Growth Scenario**: A large reduction in the load growth assumption for the entire WECC region. This scenario assumes a negative growth rate of -2.11% year-over-year on average across the entire study, using the lowest load projection from the NWPCCC described earlier. This is intended to analyze the potential impacts of a prolonged decrease in load growth due to such factors as energy efficiency and distributed generation. Historically, both of these have contributed to a reduction in demand and a continued revision downward in load forecast.

2) **High Load Growth Scenario**: An increase in the load growth assumption for the entire WECC region. In this scenario, load is assumed to increase on average by 0.34% year-over-year across the study, using the highest load projection from the NWPCCC described earlier. This is intended to look at the impacts of increased population growth, manufacturing, and electrification of the transportation industry across the WECC.
3) **High West Coast Carbon Scenario**: A flat $100 per metric ton is applied to the states of Washington, Oregon, and California starting in 2020. This scenario picked an arbitrarily high carbon price to examine the potential impact of a unified high penalty along the west coast.

4) **No Washington Carbon Scenario**: This scenario assumes the status quo remains, and that Washington does not adopt a carbon tax or a carbon trading program.

Figure 33 below is the projected resource additions in the Northwest through time under the Low Load Growth scenario. Interestingly, under the Low Load Growth scenario, about 1,300 MW less natural gas generation is built out in the region over the entire study period. However, nearly the same amount of renewables (wind and solar) are built to meet state RPS requirements. This suggests that the renewables build out in the region will likely continue regardless of load growth to meet increasing RPS mandates.

Figure 33: Forecasted Resource Additions under the Low Load Growth Scenario

![WECC_NWPP](chart.png)

Figure 34 below is the projected resource additions in the Northwest through time for the High Load Growth scenario. Note that there are significant CCGT additions in 2021/22 to meet the higher load.
Figure 34: Forecasted Resource Additions under the High Load Growth Scenario

Figure 35 is the projected resource additions through time for the High Carbon scenario. Interestingly, there is little change in the resource stack from the Base Case, likely due to the fact that the new CCGT builds in 2019-2021 are outside of the Washington-Oregon-California region with the higher carbon price of $100 per metric ton, and therefore not subject to the high carbon price in this scenario.
Figure 35: Forecasted Resource Additions under the High Carbon Scenario

Figure 36 below is the projected resource additions through time for the No Washington Carbon scenario, which is also very similar to the Base Case.
Figure 36: Forecasted Resource Additions under the No WA Carbon Scenario

The effects on power prices are illustrated below in Figure 37. As expected, the High Carbon scenario has the largest impact on market prices, and increases the forecasted Mid-C market price by about $7.00/MWh on average over the study period. As discussed above, the resource stack is little changed between the Base Case and High Carbon scenario, so the increase in price is largely a result of marginal natural gas units paying the higher carbon tax and a significant amount of the heat rate stack not paying the tax (e.g. hydro, solar, and wind generation). Note that the price difference is highest in the first year of the higher tax in 2020, where the annual average is nearly $11.25/MWh higher than the Base Case, but is less than $4.50/MWh higher than the Base Case in 2028, as there are more carbon-free resources to call upon to meet load later in the study.

The Low Load Growth scenario also has a significant impact on power prices. The average power price for this scenario is about $2.25/MWh lower on average over the entire study period, with an annual average of approximately $23.75/MWh. As mentioned earlier, the Low Load Growth scenario alters the resource stack by displacing higher cost natural gas generation and meeting load growth with a continued build out of renewable generation due to RPS requirements.
Interestingly, of these four scenarios, the two with the least impact on Mid-C market prices are the High Load and No Washington Carbon scenarios. If one assumes a moderately positive annual average load growth of 0.34% in the WECC, Mid-C prices increase by just under $2.00/MWh on average over the study period. Similarly, in the status quo carbon pricing regime, Mid-C prices are forecasted to be on average slightly less than $1.25/MWh lower than the Base Case.

Figure 37: Scenario Analysis of Mid-C Price Forecasts

It should be noted that the scenario analyses provide insight into the impacts of potential changes to key underlying assumptions in the market simulation model, rather than a statistical distribution around model results with static underlying assumptions. That is, the market simulation model assumes a given load growth and a given carbon tax assumption, and by changing the load growth or including or excluding a carbon tax, we can observe the impact given changes in key assumptions.

Section 8: Action Plan Updates
The 2016 IRP laid out an Action Plan to ensure Cowlitz PUD is able to deliver a reliable supply of electricity at a competitive cost to its retail customers. The study projected the District would remain in load/resource balance for the study period with seasonal capacity deficits appearing in the winter beginning 2018. The District has since developed metrics to better define capacity events, quantify the capacity position, developed a program to monitor and discuss capacity positions during monthly risk committee meetings, and to fill the capacity deficits when necessary.
Despite lower fuel costs, the levelized cost of a new combined cycle gas generation resource actually increased since the last study, as capacity factors are expected to decline. With fewer megawatt-hours to spread capital and fixed costs upon, overall levelized costs increased. Renewable resources are less costly, but the District is forecasted to be in a net surplus REC position through the end of the study period, and wind and solar cannot be relied on as a capacity resource without a complimentary storage asset.

Modeling from the 2016 study forecasted long-term market prices that will remain competitive with building a resource, but without the burdening the District with the carrying costs of a physical asset. The 2018 study again confirms this result.

At this time, the District elects to continue the status quo, as recommended in the 2016 IRP. However, the District will carefully monitor ongoing market and regulatory developments, such as regulatory action on carbon pricing, that may change market fundamentals.

**Section 9: Bonneville Power Supply**

As noted in the Supply-Demand overview section, the District has decided to remove BPA supply from its resource portfolio when its current 20-year power supply contract expires in October 2028. The primary drivers of this decision are simple: BPA’s initial discussions regarding post 2028 preference power supply indicate cost projections significantly above current wholesale market price forecasts and removal shines a bright light on the resulting resource gap and the importance of the decision process looming in future years (Figure 38).
Figure 38: BPA Tier 1 Cost Projections through 2030

At $42/MWh, the BPA projection is over $10 above the District’s current long term price forecast. A simplistic analysis would easily conclude that the District would be better off relying on market alternatives to meet the majority of its power supply needs. Obviously, this issue and decision process is not that simple, it will require much more consideration over time.

Wholesale Price Uncertainty

For BPA to publicly share a price point for their future power supply product, they likely have a high level of confidence they will be able to achieve this price point in the future. BPA is currently under significant pressure from its constituents to focus on cost control and to better monetize the assets under its control. On the other side, any number of unanticipated costs could arise that push BPA’s costs up. Despite both of these factors, we can assume that there is a fairly tight range around the price point BPA initially shared publicly. For the example below, we’ve assumed BPA’s Tier 1 product, in whatever form it ultimately materializes, will vary around the $42 price point by +/- $6. Overlaid on this assumed BPA price distribution, we have added the range of price outcomes modeled in our risk analysis for the 2029 calendar year (Figure 39).

The distributions above illustrate why just comparing market price forecasts to BPA price forecasts is inherently challenging, particularly with so much time between 2018 and 2029. On an expected basis, wholesale market prices for Mid-C energy will be significantly less expensive than BPA’s initial projection. That said, at least 15% of the time, future prices are higher than BPA’s expected cost. From a risk perspective, the BPA option looks relatively appealing given its narrow distribution. Keeping in mind this analysis only considers energy prices, we recognize capacity and load following attributes are included in the BPA option but not the market option.

**Additional Considerations**

Energy price, while primary, is only one component of power supply costs. Other attributes, in particular the cost of capacity and potential carbon costs (and therefore potential value of low carbon resources) must also be taken into consideration.

At this time, the Mid-C market is not capacity constrained. In the near future however, there are many externalities in play that may change this dynamic, in particular projected resource retirements and potential changes in market design. The region anticipates the retirement of most coal-fired generation resources by the mid-2020s. If these resources are replaced primarily by renewable resources, as our Aurora modeling suggests, the region may find itself valuing quick ramping, on-demand capacity at a
premium. Other regions, specifically California, already place a premium on these attributes, and those that control these resources (BPA being a major player) are looking for ways to monetize this need. This could result in market design changes or other bilateral agreements that significantly increase the cost of capacity and decrease the readily available supply of capacity in the wholesale market that we currently enjoy.

As mentioned in Section 2: Policy & Regulation, carbon policy is front and center in the Northwest. Both Washington and Oregon are working through the legislative process to attach a tax to carbon emissions in some form. BPA’s power supply is mostly carbon free and carbon legislation would either positively impact the value proposition of BPA supply, increase the cost of wholesale market solutions, or increase the cost of alternative physical resources such as Natural Gas fired generation. The District anticipates more certainty around this topic in the coming years and is actively involved in the process to ensure resulting legislation is as beneficial, or least impactful, to its customers as practically possible.

**BPA Power Supply Summary**
The District, as is the case with all Public Power entities in the NW, shares a long history with the Bonneville Power Administration. The District’s contract, and therefore obligations, are finite so it is prudent that the District explore alternatives. Given the uncertainties in legislation, market design, wholesale power costs, and alternative resource cost projections, it is premature to definitively state a path forward for October 2028 power supply now in 2018. Instead, the District will continue to monitor and engage on all fronts to ensure it meets its customers power supply needs in the most cost effective manner possible.

**Section 10: Conclusion**
In 2016 a detailed portfolio analysis concluded that the District should rely on the Wholesale market to meet its incremental needs. Since then, the District’s view of the future has changed significantly; the load forecast is approximately 100 aMW lower, long term price forecasts are $9/MWh lower, and the District projects adequate renewable generation to meet state requirements through 2028. This significant change over two years is indicative of the challenge of making declarations around resource plans that will not impact the District until a decade in the future. As such, the approach identified in 2016, specifically the reliance on wholesale market transactions to target specific needs is still valid today.

In 2020, the IRP team will further consider and evaluate plans around post 2028 power supply. By then, there should be more clarity around externalities that will impact this decision, particularly on the policy front where carbon legislation will likely have run its course and regional market design decisions will be more clear. In addition to these factors, two more years of technological advancements will have been incorporated into alternative resource cost projections for further analysis.