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Chapter 1: Executive Summary

Cowlitz PUD’s (the District) 2016 Integrated Resource Plan (IRP) lays out a strategy for meeting its energy needs, capacity demand, and Washington State renewable portfolio standard (RPS) obligations over a 20 year planning horizon from 2017 through 2036. The goal of this IRP is to provide a framework for evaluating a wide array of supply resources, conservation, and renewable energy credits. The IRP provides guidance towards strategies that will provide reliable, low cost electricity to the District’s ratepayers at a reasonable level of risk.

Cowlitz PUD is required by Washington State law to develop “a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers’ electricity needs in both the long term and the short term.” The law stipulates that Cowlitz PUD produce a full plan every four years, and provide an update to the full plan every two years. The plan must include a range of load forecasts over a ten year time horizon; an assessment of feasible conservation and efficiency resources; an assessment of supply-side generation resources; an economic appraisal of renewable and non-renewable resources; a preferred plan for meeting the utility’s requirements; and a short-term action plan.

Obligations and Resources

The majority of the District’s wholesale electricity comes from the Bonneville Power Administration (BPA) under the “Slice of the system”/ Block contract, represented by the “BPA” fields in the chart below. The Swift 2 Hydroelectric Project also augments the District’s generation supply. For planning purposes, each year is analyzed using 1937 hydro conditions, also known as the critical hydro year, representing the worst hydrological conditions on record, dating back to 1929. Critical hydro conditions represent a conservative supply scenario; the vast majority of the time the District will have more generation than what is shown in the charts below. Planning to this level provides a high probability of having adequate supply to meet demand. Cowlitz PUD under critical hydro conditions is expected to supply enough energy to meet load requirements on an average annual basis through the duration of the study period (Figure 1).
Most years, Slice generation will be greater than critical. Figure 2 displays generation from the 80 year average hydro conditions.
While the District has sufficient supply side resources to meet its annual average load obligations, there are certain times during the year when the fluctuations in hourly loads exceed the District’s generating capacity. Maximum power demand usually occurs winter mornings and evenings when electric heating loads are highest. The District currently has the capacity to serve its load during these peak periods, however, the surplus winter capacity is diminishing and is expected to be exhausted by the end of 2017. If peak load continues to grow each year by the AAGR of 0.38% then the capacity deficit is forecasted to grow by 2 to 3 MW per year. Figure 3 displays the District’s 1 hour daily peak for the past 5 years with the estimated 1 hour seasonal peak generation capacity. The Slice assumption was based on The Energy Authority (TEA) operations staff reviewing output from TEA’s Slice Water Routing Simulator (SWRS). The winter peak generation value is assumed to be 10,500 MWh; the District’s share of the generation is about 420 MW.
Figure 3: 2011-2015 1 Hour Daily Peak Loads against 1 Hour Seasonal Peaking Capacity

Figure 4 shows the District’s requirements under the Washington State renewable portfolio standard. The District is anticipated to have enough RECs to comply through 2025. However, the District will need to acquire additional RECs beyond 2025 to maintain its RPS compliance.
Preferred Portfolio
The IRP staff constructed a long term integrated financial and energy position model to forecast the District’s annual net power cost for the duration of the study period. The financial model used the results from the forecasted loads model, simulated hydro generation scenarios, forecasted output from generation resources, power price scenarios, regulatory scenarios, and forecasted generation resources. The outputs from the model measured the impact of these different scenarios in a single metric: the average cost per megawatt-hour of load served in 2016 dollars.

The District selected 4 portfolios to examine, which were input into the long term financial model and then stress tested under a variety of hydro and power price scenarios (Figure 5). The portfolio strategy that exhibits the best performance in terms of cost and risk is the status quo, which relies exclusively on market purchases for capacity and purchases of renewable energy credits to satisfy the Washington State RPS. The preferred portfolio comes in at the lowest cost, but the tradeoff is that the risk is slightly greater than other portfolios.
The performance of the various portfolios are consistent with expectations. The generation costs of acquiring a reciprocating engine and solar are both higher than forecasted market prices, thus it is expected that portfolios containing resources resulted in higher costs. It is notable, however, that the range between the lowest and highest cost portfolios is $1 per megawatt-hour of load served. It reinforces the prominent role of hydroelectric power in the District’s generation resource mix. It also suggests that the District’s inflation adjusted long term power supply costs are relatively stable.
Chapter 2: Load Forecast

A load forecast is integral to the integrated resource planning process in that it projects the District’s future energy needs. The dominance of industrial load, which accounts for a majority of the District’s load, presents a unique forecasting challenge. Whereas the average residential customer may represent an average load of one or two thousandths of a megawatt, large industrial customers may have an average load of tens or even hundreds of megawatts. The addition or loss of a single residential customer barely registers as a blip with respect to the District’s overall load. However, the appearance or disappearance of industrial customers can have significant impacts on District loads. Several large facilities with a cumulative load in excess of 100 MW are expected to come online in the next several years. However, unforeseen circumstances may alter the timing of when, or even if those loads appear. The new industrial loads were therefore reported separately such that the handful of very large loads do not distort the rest of the load forecast. The 2016 energy load forecast, excluding new industrial loads, predicts a five year average annual rate of growth (AARG) of 0.96%. This growth rate is consistent with the forecast developed for the 7th Northwest Power Plan by the Northwest Power and Conservation Council (NWPCC), which projects an AARG of 0.5% to 1.0%. By the year 2021, this would result in an increase of 25 MW over the 2016 projected load of 578 MW at the BPA Points of Delivery (POD). Figure 6 and Figure 7 are tables of the various forecasts examined in this IRP.

Figure 6: Retail Energy Load Forecast

<table>
<thead>
<tr>
<th>2016 Energy Load Forecast Without New Industrial Loads</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016-2021 (5 year) % AARG</td>
</tr>
<tr>
<td>2016-2026 (10 year) % AARG</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2016 Energy Load Forecast With New Industrial Loads</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016-2021 (5 year) % AARG</td>
</tr>
<tr>
<td>2016-2026 (10 year) % AARG</td>
</tr>
</tbody>
</table>

Figure 7: Energy Load Forecast

<table>
<thead>
<tr>
<th>2016 Energy Load Forecast Without New Industrial Loads</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016 (aMW)</td>
</tr>
<tr>
<td>2021 (aMW)</td>
</tr>
<tr>
<td>2026 (aMW)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2016 Energy Load Forecast With New Industrial Loads</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016 (aMW)</td>
</tr>
<tr>
<td>2021 (aMW)</td>
</tr>
<tr>
<td>2026 (aMW)</td>
</tr>
</tbody>
</table>

Figure 8 offers a more granular view of the forecast by annual consumption by sector. Since the load forecast is based on normal weather, and 2015 weather was anomalously warm, the historical loads were normalized to ensure an unbiased comparison. Weather normalization of the 2015 load resulted in an increase of 50,973 MWh for the year.

Figure 8: Load Forecast by Sector

<table>
<thead>
<tr>
<th>Energy Load Forecast by Sector (MWh)</th>
<th>2015 Weather Normalized Loads</th>
<th>2021 Forecast</th>
<th>2026 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential/Commercial</td>
<td>1,533,775</td>
<td>1,639,522</td>
<td>1,698,270</td>
</tr>
<tr>
<td>Large Industrial</td>
<td>3,477,139</td>
<td>4,600,801</td>
<td>4,523,351</td>
</tr>
</tbody>
</table>

Modeling Assumptions

In 2016, The Energy Authority Inc. developed a normalization and long-term load forecast model using Excel. The load forecast model is a long-term monthly load model that forecasts total energy usage for non-industrial customers, non-industrial coincidental peak demand, and system peak demand. The model normalizes historical data and utilizes a 3rd party population growth forecast to project future energy consumption.

TEA subscribes to Woods & Poole Economic Forecasts, which are updated annually, most recently in April 2016. The Woods & Poole Economics, Inc. database contains more than 900 economic and demographic variables for every county in the United States for every year from 1970 to 2040. This comprehensive database includes detailed population data by age, sex, and race; employment and earnings by major industry; personal income by source of income; retail sales by kind of business; and data on the number of households, their size, and their income. The Woods & Poole projection for each county in the United States is done simultaneously so that changes in one county will affect growth or decline in other counties. The specific economic projection technique used by Woods & Poole to generate the employment, earnings, and income estimates for each county in the United States generally follow a standard economic “export-base” approach.

According to Woods & Poole, the long-term outlook for the United States economy is one of steady and modest growth through the year 2050. Although periodic business cycles, such as the 2008-09 recession, will interrupt and change the growth trajectory, the nation’s employment and income are expected to rise every year from 2015 to 2050. Although employment growth has been uneven in recent years, with particularly sharp job losses in manufacturing, the economy is expected to stabilize and produce steady job gains.

The model utilizes the total population growth variable for the Cowlitz County region.
The TEA model is used to forecast the non-industrial load. Historical retail load and historical heating and cooling degree days are used as inputs into the normalization model. The forecast is constructed using the most recent normalized year and growth projection from Woods & Poole Economics, Inc. The future load forecasts represent normalized weather for every year. Industrial load forecasts were developed in consultation with the industrial customers.

To calculate a monthly peak forecast, coincidental peak load factor is calculated using the historical relationship between non-industrial total monthly load and the non-industrial demand during the district’s monthly peak demand hour. The calculated coincidental peak load factor is then applied to the monthly load forecast to generate peak demands for every month.

**Conservation Effects on Load Forecast**

As a result of Cowlitz PUD’s continued commitment to conservation over the past 25 years, the 10 year load forecast has some of the utility’s future potential conservation built in through its modeling techniques. The regression load forecast program analyzes historical trends and inherently incorporates historical conservation energy savings in the forecast resulting in similar conservation savings continuing into the future. The non-industrial conservation plan is consistent with achievement over the past few years, thus the regression program incorporates the conservation plan in the forecast. Industrial conservation programs differ from residential programs and are separately and specifically reflected in the industrial load forecasts.

Since the District incorporates conservation in the load forecast by its modeling technique it is not later considered an option to meet future load growth as compared to other resources in this IRP. It is assumed all cost effective conservation is achieved and then resource options are considered for the remaining load requirements, if any.

**Load Forecast Uncertainties**

While every effort is made to have the most accurate forecast possible, the unknown is always a factor when looking ten years into the future. Additional uncertainties are introduced when considering the District’s heavy concentration of large industrial loads. Hundreds of megawatts of load can be gained or lost with the introduction or exit of a single industrial customer.

The District examined two additional load scenarios to determine the impact on the portfolio if load growth were higher or lower than forecasted. Energy efficiency is expected to play a large role in future load trends. The Council’s 7th Plan projects that the region will be able to meet all future load growth with energy efficiency. In the current forecast, the District’s load is parabolic: it is expected to grow until 2020 at which point it plateaus, and then begins to decrease due to the effects of conservation.

The “high” load scenario examines the consequences of less successful energy efficiency measures. In this scenario, energy efficiency targets stalling beginning 2020 for the large industrial customers. The result is that the 10 year AARG increases by 60 percent over the base case forecast from 0.38 percent to 0.61 percent.
The “low” load scenario investigates the impact of a more successful energy efficiency program that results in a zero load growth steady-state beginning 2020.

Chapter 3: Current Resources
The District sources its power requirements through purchases from BPA as well as from several non-federal sources of power. This section provides an overview of the District’s existing resource portfolio and concludes with a description of the projected resource deficit beginning 2023 that will need to be filled from non-BPA 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 2 hydroelectric project, and a share of the Wanapum and Priest Rapids Hydroelectric Projects. Wind resources include the White Creek wind, Harvest wind, and Nine Canyon wind 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.

Overview of Generation Assets

Nine Canyon Wind
The District entered into a Nine Canyon Wind Project Power Purchase Agreement with Energy Northwest for the purchase of 2 MW of the project generating capacity. This purchase produces less than 1 aMW of energy. The project reached commercial operation in late 2002, and the original term of the District’s purchase commitment continues through June 30, 2023. Nine Canyon Wind provides an intermittent source of energy for the District. There is no material difference in the amount of energy the District receives from month to month.

White Creek Wind Generation Project
Cowlitz PUD is the offtaker to 46 percent of the energy produced by the 205 MW White Creek Wind Generation Project near Goldendale, WA. Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 x 2.3 MW turbines that began producing power in November 2007. White Creek is a renewable energy resource that produces environmental attributes which helps Cowlitz PUD meet its I-937 renewable requirements. Cowlitz PUD has contractual rights to a portion of the project’s output, including all associated environmental attributes, through 2027. With a capacity factor of just over 30 percent, Cowlitz PUD receives an average energy output of 31 MW from the project.

Harvest Wind Project
The Harvest Wind Project is adjacent to the White Creek Wind Project near Roosevelt, WA. It consists of 43 x 2.3 MW wind turbines that together have a generation capacity of 98.9 MW. The project was
developed and is owned by four Pacific Northwest utilities: Cowlitz PUD, Peninsula Light, Lakeview Light & Power, and Eugene Water and Electric Board. Cowlitz PUD has a 30 percent interest in the project, entitling it to 29.7 MW of generation capacity. The construction of Harvest Wind met certain conditions put forth by the Washington State Apprenticeship and Training Council. As a result, it produces Washington state eligible environmental attributes at 1.2 times the base accrual rate, helping Cowlitz PUD meet its I-937 standards with fewer resources.

Cowlitz PUD’s average share of the total output is 8.9 MW of energy, assuming a 30 percent capacity factor.

**Swift No. 2 Hydroelectric Project**

With a generation capacity of 70 MW, the Swift No. 2 Hydroelectric Project is located on the North Fork Lewis River near Cougar, WA in Cowlitz County. It was originally built by Cowlitz PUD in the 1950s, and then rebuilt in 2006 after a catastrophic failure in 2002. Like the FCRPS, energy output from Swift 2 fluctuates with hydrological conditions. While the hydroelectric projects of the FCRPS are predominantly located east of the Cascades, Swift 2 is located west of the Cascades. This provides Cowlitz PUD with a bit of diversification in its hydroelectric portfolio. Weather patterns and hydrological conditions on the western side of the Cascades can differ from those on the eastern side of the mountains. FCRPS generation is dependent on hydrological conditions on the Columbia River, while Swift 2 is located on the Lewis River, which is supplied by a different snowpack and water source. Its output can be optimized to meet Cowlitz PUD’s operational demands with minimal other considerations. In other words, it can be turned on and generate electricity during periods of higher demand and turned off in low demand periods. Swift 2 has an average energy output of 14.6 MW in critical water conditions and 28 MW in average hydrological conditions, based on a 70 year historical mean.

**Wanapum and Priest Rapids Dams**

Grant County PUD owns and operates two large hydroelectric dams along the Columbia River – Wanapum and Priest Rapids dams. When the dams were first built in the 1950s, the supply of electricity from the dams far exceeded the demand in Grant County. Surplus generation was sold off to nearby utilities, such as Cowlitz PUD, which has been a purchaser since then. As recently as 2011, Cowlitz PUD received 25 MW of energy from the two projects. However with electricity demand rising in Grant County, Cowlitz PUD’s ability to purchase this electricity is diminishing. Cowlitz PUD expects to receive 1 aMW of energy from these projects for the foreseeable future.

**Federal Resources**

The Federal Columbia River Power System (FCRPS) is managed and operated by a joint collaboration of three federal agencies: the U.S. Army Corps of Engineers (Corps of Engineers), the Bonneville Power Administration (BPA), and the Bureau of Reclamation. It consists of 31 multipurpose dams which provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration, n.d.). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply
conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period of time. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that time period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1929-2015) is illustrated in the figure below.

**Figure 9: Historical Water Years (1929-2015)**

The 1937 water year streamflows represented one of the worst (lowest) on record at the time it was chosen as the benchmark “critical water” year. The significance of the critical water designation is that it represents baseline system capability – in other words, even in very poor hydrological conditions, the FCRPS is still expected to generate at the minimum critical level. BPA conservatively measures the system capability by determining its average annual energy output in critical water conditions. For the 2016 and 2017 water years, the system capability is 7,034 aMW and 6,932 aMW respectively (slightly lower due to refueling outage at CGS). System generation will exceed 7,034 aMW and 6,932 aMW in non-critical water years, which should occur the vast majority of the time.

As a Tier 1 Slice/Block customer, Cowlitz PUD is allocated a certain portion of the system to manage and operate to serve its load. Each BPA customer was initially allocated a certain portion of the system such that on an annual average energy basis, and based on 2010 adjusted loads and declared resources, the customer is in load/resource balance. Cowlitz PUD can receive up to 7.7896% of the FCRPS. The quantity
of power a utility is entitled to is known as its Contract High Water Mark (CHWM). The amount of power a Tier 1 customer is entitled to purchase is its Rate Period High Water Mark (RHWM), which is determined from the CHWM adjusted for any increases or decreases in the system capability for the rate period. BPA power alone will not meet the District’s energy needs on a planning basis; the District relies on other generation resources to provide additional energy, which are outlined in this chapter.

**Figure 10: Retail Load vs. BPA Contract High Water Mark**

![Retail Load vs. BPA Contract High Water Mark](image)

The system allocation is calculated by dividing a utility’s RHWM (or net requirements, whichever is lower) by the sum of all utilities RHWM (which is approximately equal to the Tier 1 system capability under critical hydrological conditions) resulting in a Tier One Cost Allocator (TOCA).

The Tier 1 rate is based on the cost of the existing federal system with very little augmentation. If preference customers choose to buy more power from BPA beyond their HWM, this power is sold at a Tier 2 rate, which fully recovers BPA’s incremental costs of securing additional resources to serve this load. Major components of the Tiered Rate Methodology include:

- Tier 1 priced at cost of existing system
- Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)
- Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The BPA product is divided into two components: fixed and variable. The fixed component, or “Block,” is a known and guaranteed quantity of power that Cowlitz PUD receives from BPA, irrespective of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to Cowlitz PUD does not change. Block power is delivered in flat monthly blocks, shaped to follow the District’s monthly load profile. In other words, more Block power is delivered in higher load months and vice versa. The variable component is “Slice”. The average energy output from the Slice
system is expected to average 9,539 aMW for the two year rate period, but daily generation will fluctuate from between 4,000 aMW to greater than 15,000 aMW. The FCRPS is a multipurpose system and power generation achieves only one of the system’s goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. Cowlitz PUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. At times, being a Slice customer requires Cowlitz PUD to fulfill its load obligations with resources other than what is provided by BPA.

The District is expected to receive its full RHWM allocation from BPA beginning October 2018 through the end of the study period. Cowlitz PUD’s share of output is about 367 aMW from the Slice portion plus an additional 272 aMW of Block power in an average water year. The Slice output can vary substantially depending on hydrological conditions, but the Block generation remains constant. Under substantially worse than average water conditions, known as critical water conditions, the District’s aggregate Slice/Block generation is equal to its annual RHWM, or 551 aMW. Better than critical water conditions translate to a total system output greater than 7,149 aMW. Based on a 70 year historical mean of hydrological conditions, the expected average system output is 9,604 aMW. Critical or worse hydro conditions have been observed in five of the previous 89 years on record, or slightly more than once every two decades. In all other hydro conditions, system generation should exceed 7,149 aMW. The District’s BPA allocation, while accounting for nearly 90 percent of its generation resources, is by itself insufficient to cover all of Cowlitz PUDs energy needs. However, the other District owned or contracted resources are sufficient to cover the difference.

**Columbia Generating Station**

The largest federally owned, non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. Cowlitz PUD’s share of output from CGS is equivalent to its Slice system allocation.

**BPA Renewable Energy Resources**

The BPA contract also includes several resources with Western Renewable Energy Generation Information System (WREGIS) registered RECs. Those resources are the Stateline Wind Project, Condon Wind Project, and Klondike Wind Project.

- The Condon Wind project is located in Gilliam County, OR. It came online in December 2001 with a capacity of 49.8MW. Klondike I & II are located in Sherman County, Oregon with a combined generation capacity of 261.2MW. BPA has rights to 63.4MW of capacity from the project.
The Stateline project straddles both Walla Walla County, WA and Umatilla County, OR. It has a nameplate capacity of 300MW. BPA has rights to 90MW of its total capacity.

BPA has rights to 246.4MW of wind generating capacity in the WECC region. The energy and RECs associated with the wind resources are included in the BPA Tier 1 rate. Cowlitz PUD’s entitlement of those resources is approximately 15.5 MW of capacity. Assuming a capacity factor of 30 percent, the District receives an average of 4.7 Tier 1 RECs per hour or roughly 41,000 RECs per year. However, the District is only able to utilize 9,000 of those RECs for RPS compliance annually.

The new RD Slice contract also includes Incremental Hydro Tier 1 RECs associated with incremental generation from efficiency upgrades such as Grand Coulee Dam, Bonneville Dam, Chief Joseph Dam, and Cougar Dam. The RECS from all hydro efficiency upgrades allocated by BPA are not currently eligible for Washington Renewable Portfolio Standard.

Load/Resource Balance with Existing Resources
Figure 11 compares Cowlitz’s long-term load forecast to the District’s projected BPA HWM plus resources already under contract.

Figure 11: Annual Base Case Loads and Existing Resources in Critical Water Conditions
The District is in an energy surplus resource position under expected load and critical water conditions through the entirety of the study period. A similar picture is painted for the “high” and “low” growth scenarios. In the “high” load scenario, the District will still carry energy surpluses throughout the study period. By 2036, however, the District is forecasted to be very close to load/resource balance (Figure 12).

**Figure 12: Annual High Load Scenario and Existing Resources in Critical Water Conditions**

A “low growth” load scenario would similarly result in the District possessing sufficient resources to meet its energy needs on a critical water planning basis (Figure 13).
Figure 13: Annual Low Scenario Loads and Existing Resources in Critical Water Conditions

Figure 14 compares Cowlitz’s long-term load forecast under the base case scenario and average hydro conditions to the District’s projected BPA HWM plus already contracted for resources.
In this scenario the District is not expected to have any deficits through the entire study period. The IRP team described the role of large industrial loads in Chapter 2: Load Forecast. While the District is expecting a handful of large loads to come online within the timeframe of the IRP study period, these entities are expected to procure the resources to serve their own load. Since the District is not expected to be depended on to procure a source of energy to meet the needs of these customers, the IRP team omitted these loads from the load forecast.

Although the District is surplus energy on an annual load/resource view, the District does have hourly capacity shortages when the demand exceeds the District’s supply. This is discussed in further detail in Chapter 7: Capacity Requirements, Energy Storage, and Demand Response.

I-937 requires the District to supply the following amounts of its load requirements with renewable resources: 3 percent by 2012, 9 percent by 2016, and 15 percent by 2020. As shown, I-937 in large part reduces the IRP process to developing a plan for acquiring renewable resources and all cost-effective conservation.

Figure 15 displays the annual REC supply and requirement for the duration of the study period. Washington State allows utilities to carry over unused RECs from the previous year for up to 1 year which
can then be retired for future year compliance. The District is expected to be surplus RECs until at least 2026, after the RPS notches up to 15 percent. Beginning 2026, the District is projected to carry annual REC deficits of 62,000 RECs which will increase to 72,500 RECs in 2027 before decreasing to 48,900 RECs in 2036. Since RPS is a function of load, the projected decrease in loads beginning 2027 will also reduce the amount of RECs needed to fulfill its RPS compliance.

Figure 15: REC Resource Balance though 2036
Chapter 4: Policy & Regulation

In recent years, environmental policy has been a primary driver of the resource planning processes. State mandated portfolio standards oblige utilities across the WECC to acquire renewable resources and aggressively pursue conservation measures. Some utilities have dramatically altered their long term strategies based on expectations of federal carbon emission laws coming into effect. The District must balance its obligation to meet regulatory requirements with the duty to acquire resources that are “least cost” and help mitigate financial volatility. The purpose of this chapter is to provide an overview of the policy issues most relevant to the District. In later chapters there will be in-depth discussion of the methodologies used to incorporate policy implications in the planning process.

Washington State Specific Policies & Regulations

Integrated Resource Planning

In 2006, the Washington State legislature passed RCW 19.280 which mandates that electric utilities develop “comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers’ electricity needs in both the long term and the short term.” The law applies to utilities that have more than 25,000 customers and are not load-following customers of the Bonneville Power Administration. The law stipulates that qualifying utilities produce a full plan every four years beginning in 2008, and provide an update to the full plan every two years. The plan must include a range of load forecasts over a ten year time horizon; an assessment of feasible conservation and efficiency resources; an assessment of supply-side generation resources; an economic appraisal of renewable and non-renewable resources; a preferred plan for meeting the utility’s requirements; and a short-term action plan.

The legislation defines an IRP as a plan describing the mix of generation resources, and improvements in the efficient generation, transmission, distribution and use of electricity that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers and that complies with the requirements in the legislation by including, at a minimum:

a. A range of forecasts of future customer demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses

b. An assessment of technically feasible and commercially available efficiency improvements in the generation, delivery, and use of electricity, including load management and fuel switching, as well as currently employed and new policies and programs needed to obtain the efficiency improvements

c. An assessment of technically feasible and commercially available utility scale generating technologies including, but not limited to, renewable resources, cogeneration, power purchases, and thermal resources
d. An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws

e. An evaluation comparing the cost-effectiveness of generating resources with the cost-effectiveness of efficiency improvements in the delivery and use of electricity

f. The integration of the demand forecasts and resource evaluations into a long-range integrated resource plan describing the mix of resources and efficiency measures that will meet current and future needs at the lowest reasonable cost to the utility and ratepayers

g. A short-term plan outlining the specific actions to be taken by the utility consistent with the long-range integrated resource plan

h. For all plans subsequent to the initial integrated resource plan, a progress report that relates the new plan to the previous plan.

The District complied with the requirements of this legislation in September of 2008, 2010, 2012 and 2014, and has now prepared this 2016 IRP.

Energy Independence Act (EIA)

In 2006 Washington State voters approved the Energy Independence Act (EIA, commonly referred to as I-937) which requires all utilities with customers exceeding 25,000 to meet 15% of their load from qualifying renewable resources by 2020. The law also mandates that utilities implement all cost-effective conservation measures. The second phase of the standard is now in effect and requires qualifying utilities meet 9% of retail loads with renewables. In 2020 the requirement will increase to 15%. Utilities subject to the Act that fail to meet the requirement will be assessed a $50/MWh, in 2007 dollars, penalty. This equates to $57.93/MWh today. The first tier EIA requirements for the District began in 2012 when 3% of load were served with renewable resources. The District has been acquiring all cost effective conservation pursuant to the EIA requirements since 2010.

Initiative 937 relates to requirements for acquiring new energy resources. I-937 requires that: (1) each qualifying utility shall pursue all available conservation that is cost-effective, reliable and feasible, and (2) each qualifying utility shall use renewable resources or acquire renewable energy credits or a combination of both, to meet the following annual targets.

a. At least three percent of its load by January 1, 2012, and each year thereafter through December 31, 2015;

b. At least nine percent of its load by January 1, 2016, and each year thereafter through December 31, 2019; and

c. At least 15 percent of its load by January 1, 2020, and each year thereafter.
I-937 requires that by January 1, 2010, using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan, each qualifying utility shall identify its achievable cost-effective conservation potential through 2019. Beginning in 2010 and updated at least every two years thereafter, each qualifying utility shall establish and make publicly available, a biennial acquisition target for cost-effective conservation and meet that target during the subsequent two-year period. The District publishes such Conservation Potential Assessments to its website.

**Washington Green House Gas Legislation**

The Washington state governor has initiated a greenhouse gas emissions policy that resulted in legislation, SB 6001, being passed to mitigate the impacts of climate change. This legislation establishes greenhouse gas emissions (“GHG”) reduction and clean energy economy goals for Washington State. SB 6001 also establishes a performance standard for all baseload electric generation, modeled on California’s Senate Bill 1368. SB 6001 would apply to all generation used to serve load in Washington, whether or not that generation is located within the state. The statute defines baseload generation as generation that is “designed and intended to provide electricity” at an annualized plant capacity factor of at least 60 percent.

Beginning July 1, 2008, electric utilities entering into a “long-term financial commitment” for baseload generation must show that the baseload generation complies with the GHG emission performance standard. The performance standard applies to both investor and consumer-owned utilities such as the District. “Long-term financial commitment is defined as (i) any new or renewed contract for baseload electric generation with a term of five or more years, (ii) a new ownership interest in baseload electric generation, or (iii) the modification of a baseload electric generation facility designed primarily to increase the capacity of the facility. The emissions standard would also apply to any baseload electric generation that commences operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state.

Baseload generation facilities must initially comply with 1100 pounds of CO2 per megawatt-hour GHG limit.

The goal of SB 6001 is to lower GHG emissions to 1990 levels by 2020, 25% of 1990 levels by 2035 and 50% of 1990 levels by 2050 (Figure 16).

**Figure 16: Target GHG Emissions**

<table>
<thead>
<tr>
<th>Year</th>
<th>Emissions (MMTCO$_2$e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>88.4</td>
</tr>
<tr>
<td>2035</td>
<td>66.3</td>
</tr>
<tr>
<td>2050</td>
<td>44.2</td>
</tr>
</tbody>
</table>

SB 6001 established an emissions performance standard (EPS) which limits CO2 emissions from any baseload electric resource to 1,100 lbs/MWh. Starting in 2013, the law can be amended to lower the
emission limit to the emission rate of the most efficient commercially available combined cycle combustion turbine. In March of 2013 the Department of Commerce lowered the emissions performance standard to 970 lbs/MWh. The CO₂ emissions from a coal-fired power plant are close to 2000 lbs/MWh, well in excess of the new standard.

**Carbon Pollution Tax (Initiative 732)**

On the upcoming November 2016 ballot is Initiative 732, which would create a tax on carbon emissions, including those from the electricity generated by fossil fuels. Furthermore, the Initiative would cover both electricity generated in the State of Washington and that which is wired into the State. The tax would start in 2017 at $15 per metric ton (PMT) of carbon dioxide emissions, increase to $25 PMT in 2018, and continue to increase by an additional 3.5% plus inflation annually from 2019 onward until it reaches $100 per ton in 2016 dollars. The initiative is intended to be revenue-neutral, with the tax on carbon being offset by a number of tax breaks, including a reduction in the State sales tax by 1%, a reduction in the business and occupation tax on manufacturing, and would provide rebates to low-income working families.

Of particular concern to the District is that I-732 would treat all market purchases from unspecified sources as though they have a carbon dioxide content of 1 metric ton per MW, equivalent to that of one MW generated from a coal plant. Many market purchases, however, come from sources with much less carbon content, such as hydropower, wind, solar, natural gas, and biomass. This tax will likely increase the cost of power in the Pacific NW, as such market purchases are necessary for reliable and cost-effective load-resource balancing.

Regardless of the outcome of I-732 this fall, it is likely that some form of a carbon tax will become Washington State law in the near future and will have a significant impact upon the energy sector. As such, in the Market Simulation chapter of this IRP, we have analyzed a scenario in which a carbon tax is applied to power plants in Washington State (
Chapter 8: Market Simulation).

Clean Air Rule
In 2015 Governor Jay Inslee tasked the Department of Ecology, under 2008 legislation for Washington State’s Clean Air Act, to come up with a rule, the Clean Air Rule (CAR), which would implement a cap on carbon emissions. After first releasing a draft rule in January 2016, Ecology withdrew it after a public response period, and, based on the public input, released a second draft rule in June 2016. The current proposed rule, which is expected to be finalized by the end of Summer 2016, is intended to lower GHG emissions to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below 1990 levels by 2050.

The CAR initially applies to power plants, natural-gas distributors, refineries and waste facilities that release at least 100,000 metric tons of carbon a year, and will begin in 2017 with 24 facilities. The 100,000 metric ton threshold for inclusion in the program decreases by 5,000 metric tons every three years until it reaches 70,000 metric tons in 2035, at which point it will remain constant, and approximately 60-70 participants are expected by 2035.

After Ecology sets a baseline emission level for each facility (based on average yearly emissions between 2012 and 2016), the facility must reduce its carbon emissions by 1.7% per year through 2035. The emissions reduction requirements can be met through a variety of ways, including efficiency gains that reduce emissions, creation of new projects that reduce carbon pollution in Washington, or the purchase of allowances from other established multi-sector carbon markets approved by Ecology. Allowance purchases, however, are capped at 50% starting in 2026, and 5% starting in 2035. Emission reduction units can be banked for later use or sale in future years, but expire after 10 years.

An important detail to note is that Washington-based power plants can comply with the CAR by adhering to the Federal Clean Power Plan (CPP) once a Washington State-specific plan to meet the CPP is established. However, there is no clear transition plan from the CAR to the CPP when the latter is scheduled to go into effect in 2022, as the structure, incentives and ultimate impacts of the two laws are significantly different. In addition, since the U.S. Supreme Court issued a stay in February 2016 to the EPA’s implementation of the CPP, it is unclear exactly when a transition to this route for compliance will be possible.

One potential major omission with the draft Rule is that electricity wired in from outside of Washington is not covered. This may have unintended consequences, such as an increase in out-of-state power purchases, including those from non-renewable resources. If the Rule does not trigger a change of the generation stack and result in the construction of more low or zero carbon resources, one of the results may be a shift in carbon pollution from Washington to nearby states.

Colstrip Decommissioning Bill
The Bill allows Puget Sound Energy (PSE) to set aside funds to pay for the future decommissioning of the two older Colstrip units in Montana. The Bill was originally crafted to call for shuttering Colstrip, but it was subsequently amended to simply allow PSE to collect funds to pay for that process sometime in the future. The takeaway is that this is further evidence that more coal retirements are on the horizon, and
for the Market Simulation base case in this IRP, we assume that Colstrip’s older Units 1 and 2 (total capacity of 614 MW) will be retired and out of service by 2026.

Puget Sound Energy and Talen Energy announced in July 2016 an agreement with environmental groups in Montana to close Units 1 and 2 of the Colstrip Generating Station by July 2022. News of this agreement came after the market simulations were completed.

**Oregon Clean Energy Bill (Oregon SB 1547)**
The effects of this law are twofold. First, it will result in the retirement of all coal and coal-by-wire into Oregon by 2030. It also creates a RPS mandate for IOUs and large public utilities of 27% renewables by 2025, 35% by 2030, 35% by 2035 and 50% by 2040.

Outside of Oregon, this law may set a precedent for other states like Washington to follow suit. California and Oregon both now have 50% RPS mandates; more renewable buildout in Oregon is expected, particularly in Oregon because of how the bill is structured. It limits the amount of unbundled out of state RECs a utility can purchase to meet its RPS obligation to 20 percent.

**Net Metering**
The District will comply with RCW 80.60.020, 80.60.030, and 80.60.040, which requires utilities to offer net metering programs to customers who have installed small generating systems, limited to water, solar, wind, biogas from animal waste as a fuel, fuel cells, or produces electricity and useful thermal energy from a common fuel source. To be eligible for net metering, each installation must be 100 kW or less in size. The total net metering capacity for each utility is set at the 0.5% of the utility’s 1996 peak demand (roughly 4 MW). Excess generation at the end of each bill period will be carried over to the next billing period as a credit. Any excess generation accumulated during the previous year will be granted to utilities without any compensation to the customer-generator on April 30 of the following year.

**Voluntary Green Power**
Legislation passed in 2001 requires large electric utilities to provide their retail customers voluntary option to purchase qualified alternative energy resources. This is often referred to as green power. Cowlitz PUD offers customers the ability to buy renewable attributes from renewable generators. The program is voluntary and retail customers can contribute any amount above the existing retail rate for their rate class. There are no state mandated reporting requirements associated with RCW 19.29a.

**Federal Policies & Regulations**

**Clean Power Plan**
The EPA’s Clean Power Plan (CPP) calls for a national carbon emission reduction of 32% by 2030 (up to 44% in some states). This will have a significant impact on each state’s resource mix, which will directly impact long-term price projections, and consequently affect utilities and their customers. The CPP requires all states to submit their final plan for emission reduction by September 2018 with the actual compliance period starting in 2022. Individual states may choose to create a statewide rate-based goal measured in pounds of CO₂ per megawatt-hour or a statewide mass-based goal measured in total short
tons of CO₂ emissions. Washington’s specific CO₂ emissions goals for 2030 are 983 lb CO₂/MWh or 10.7 million short tons of CO₂ per year.

The CPP’s impact on Washington, Oregon, and Idaho is projected to be relatively minimal given the reliance on zero-carbon hydropower in addition to the planned retirement of the remaining coal-fired generation units in Washington and Oregon, Centralia and Boardman, respectively. Other states, notably Montana and Wyoming, will have more significant hurdles towards achieving these emission reduction targets. Given these more demanding requirements on other states, many of these states have challenged the legislation. Although the U.S. Supreme Court granted a stay on the CPP in February 2016, and a final court ruling is unlikely to occur until late 2017 or early 2018, for the purposes of this IRP, we are assuming that the CPP will be enforced as currently written.

**PURPA**

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including the District) to consider certain standards for rate design and other utility procedures.

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities “of 80 MW or less whose primary energy source is renewable [hydro, wind or solar], biomass, waste, or geothermal resources.”

The FERC leaves it to the states to determine the implementation of PURPA-based contracts, and this has had a significant impact in how many QFs have been built in a given state. Idaho had a short-lived solar surge that resulted in about 400 MW of PURPA approved solar energy contracts with an additional 1,300 MW seeking approval until the state PUC slashed the length of negotiated QF contracts from 20 years to 2 years. The change in PURPA rules resulted in the withdrawal of most of those contracts that did not already have approval. In June 2016, the Montana PSC issued an emergency order suspending guaranteed PURPA contracts to small solar farms in response to a large number of applications, as many as 130 projects. Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices – a favorable ruling for renewable developers. Washington, on the other hand, does not have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers.
Chapter 5: Supply Side Resource Costs

The District analyzed a broad array of supply-side resource options in the IRP. Each technology has its own unique set of advantages and disadvantages, and therefore, a unique impact on the District’s power supply costs. The resources considered in the plan are not a complete list of all possible generation types. Rather, the IRP reflects technologies that are deemed to be realistic candidates by the District’s IRP team.

The District gathered resource cost data from a variety of sources. In general, the plan attempts to base its analysis on “regional consensus” data. This was accomplished by surveying and averaging the assumptions used by other utilities in the region for their IRPs. In circumstances where the District had access to more specific resource cost data, that information was used instead.

A project economics model was developed as a means to evaluate the different variables across the various generation resource options. The model considered both resource specific data such as capital, operating, and fuel expenses, as well as non-technical expenses such as the cost of carbon and environmental compliance. The model was developed to compare the effect of the different variables across the generation technologies through a simplistic levelized cost of energy ($/MWh) metric.

Resource Alternatives

Generation resources considered in this IRP are all that can be considered technically, financially, and financially feasible. Some resources were precluded on the basis of regulations, others were due to the technical immaturity, or a combination of both.

Resources Not Considered

Resources such as coal, nuclear, large hydro, and geothermal were not considered viable resource alternatives in this IRP. RCW 80.80 dictates that new power plants with expected capacity factors of greater than 60 percent must meet an emissions performance standard of less than 1,100 lb CO₂/MWh, adjusted annually to the benchmark of the most efficient commercially available combined cycle natural gas fired generator. This regulation all but eliminates the new construction of coal projects in Washington without carbon capture and sequestration (CCS) capabilities. At this time, CCS is not considered a viable resource alternative.

The current generation of commercially available nuclear power plants are large-scale, with generation capacities in the thousands of megawatts. These are also the ultimate baseload resource: nuclear power plants tend to operate with a steady output. These are characteristics that aren’t necessarily compatible when the region is in a period of little or no electricity load growth and when renewable energy integration increasingly requires resources with the flexibility to quickly adjust its output. Nuclear energy also has additional political and financial hurdles that it needs to clear before a plant can be built. Small modular reactors are being touted as the next generation of nuclear power plants that will be, as described in the name, smaller and modular in nature. However, these plants are still years away from being commercially available.

Large hydro plants if built today, such as Grand Coulee and the other legacy dams featured along the Columbia River, would be very cost prohibitive and would face substantial hurdles to meet today’s environmental standards. As such, large hydro plants were not considered as resources. These are
different from the smaller “run of the river” dams in the single digit megawatt size that the National Renewables Energy Laboratory (NREL) still defines as renewable resources. These do not utilize a reservoir behind the dam, rather, a portion of the stream is diverted into a powerhouse containing the turbines which minimizes the impact on the natural flow and wildlife of the stream or river.

Most of the geothermal resources that can be developed into power plants are already developed. The next generation of geothermal power plants require drilling into hot rock deep below the earth’s surface. The technology is still years away from economic viability, and thus the resource is not considered available for the timeframe of this IRP.

**Nonrenewable Resources**
Natural gas produced less than 20 percent of the electricity consumed in the United States a decade ago. It is nearly 35 percent today. In recent years, natural gas generators represent nearly all of the newly installed power plant capacity fueled by non-renewable resources. This trend was driven in part by market forces; the influx of a cheap, abundant, and domestically available supply of natural gas, and in part by pollution control regulations that rendered older coal plants obsolete or requiring extensive and expensive upgrades. Three types of natural gas plants are examined in this report, each with its own set of advantages and disadvantages.

Natural gas pipeline capacity must also be taken into account when evaluating the resource. The currently available capacity in the Northwest pipeline infrastructure today is expected to be exceeded with increased natural gas demand. Several large natural gas dependent industrial customers are expected to begin operations before the end of the decade in addition to a proposed LNG export terminal are expected to exceed the available pipeline capacity in the region.

**Simple cycle gas turbines (SCGT)** are generally used sparingly in the Northwest as a peaking resource during periods of high demand, such as a cold winter morning or hot summer evening, or to integrate intermittent renewable resources. SCGTs have the advantage of having the lowest capital costs for natural gas resources, fast dispatch, short construction time, and a small footprint. The primary disadvantages are low thermal conversion efficiencies.

**Reciprocating engines** for the most part perform the same role as SCGTs but provide better balancing capabilities. These are fast ramping machines that can be used to serve peak load or integrate resources. Reciprocating engines are modular by nature and can effectively be built to any size. Reciprocating engines have a reputation of being reliable – these are nearly the same machines used to power and drive large ships – and must stand up to the rigors of the maritime industry.

**Combined cycle gas turbines (CCGT)** can simplistically be described as SCGTs with an additional heat recovery steam generator module attached to capture waste heat from the SCGT and drive a steam turbine. The result is a higher efficiency, lower emissions factor plant than SCGTs or reciprocating engines. CCGTs have a different role in the generation stack than SCGTs. These are slower ramping, high capacity factor plants designed to maximize thermal efficiency and provide a steady output of power. Relative to coal plants, CCGTs require a lower capital investment, have similar fuel costs, are easier to permit and site, are more efficient, and require far fewer pollution control technologies in order to comply with new regulations. It is for these reasons that CCGTs are increasingly displacing coal as the baseload resource of choice for utilities around the nation.
Renewable Resources

Renewable technologies, wind and solar in particular, experienced significant growth in the last several years. Wind and solar made up well over half of all US generation capacity additions in 2015. Nationally wind capacity additions totaled about 8,300MW and solar amounted to nearly 7,300MW. The rapid increase of renewable capacity can be attributed predominantly to the improved economics of renewable resources, continued Federal financial incentives, and increasing RPS requirements.

There are two Federal incentives available to renewable resources: the Production Tax Credit (PTC) and the Investment Tax Credit (ITC). Both programs received multi-year extensions at the end of 2015. The PTC provides a tax credit to eligible renewable generators for each kilowatt-hour of electricity produced for the first 10 years of operation. Wind, geothermal, and biomass technologies receive $23/MWh. All other eligible technologies (i.e. tidal or small hydro) receive $12/MWh. The PTC received a 4 year extension beginning 2016 that gradually reduces the subsidy by 20 percent each year to wind generators until it phases out on December 31, 2019.

- Wind generators that begin construction in 2016 receive the full amount of the PTC
- Wind generators that begin construction in 2017 receive 80% of the PTC
- Wind generators that begin construction in 2018 receive 60% of the PTC
- Wind generators that begin construction in 2019 receive 40% of the PTC

There are several differences between the PTC and ITC. The subsidy amount provided by the ITC is a percentage of the installed capital costs instead of a fixed rate per unit of energy provided. It is also applied based on the in-service date, rather than the construction start date.

The subsidy schedule for the ITC varies significantly by generation resource and gradually ramps down until its expiration. The table below displays the credit provided by the ITC as a percent of capital expenditures.

<table>
<thead>
<tr>
<th>In-Service Date</th>
<th>End of 2016</th>
<th>End of 2017</th>
<th>End of 2018</th>
<th>End of 2019</th>
<th>End of 2020</th>
<th>End of 2021</th>
<th>End of 2022</th>
<th>Beyond</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>26%</td>
<td>22%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>30%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Wind</td>
<td>30%</td>
<td>24%</td>
<td>18%</td>
<td>12%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

The renewal of the production and investment tax credits for wind and solar energy beyond 2016 will likely result in the continued growth of renewable capacity.

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**Wind turbines** are the renewable resource of choice for utilities in Washington State. Advances in technology increased the generation capacity of onshore turbines upwards of 3MW, with some offshore turbines capable of generating up to 10MW. Capacity factors also increased from the 30 percent range in the mid-2000s to upwards of 50 percent today in locations with excellent wind conditions, such as the Midwest and West Texas. Wind generators in Washington are unlikely to reach such high capacity factors with the current state of technology. Combined with Federal incentives, wind energy represents the lowest cost resource in many places in the Midwest. Wind energy, however, is still an intermittent resource that requires a dispatchable resource to integrate the energy to the grid. It also largely generates energy at night and during the spring, when there is less demand for it.

**Solar** costs have decreased to the point where rooftop solar is competitive with retail rates and utility scale solar can be produced at a lower cost than new natural gas fired generation in certain regions. Neither statement is true at the moment in Washington State because the solar resource is not strong enough in the region. However, the pace of technological evolution suggests that solar energy will be produced at a lower cost than natural gas in the state, particularly east of the Cascades where there is a higher quality solar resource. It will be much more difficult to clear that hurdle in Western Washington where the solar resource is among the worst in the nation. The IRP team assigned utility scale solar plant capacity factors of 14 and 20 percent for plants sited in Western vs. Eastern Washington, respectively.

**Biomass and landfill gas** play a small role in the regional generation resource mix. Biomass plants consume the residual waste from the forest products processing industry. The weight and low content heating value of the fuel would render transport uneconomic, thus power plants must be located within close proximity of the fuel source. Biomass is only a viable option because of the forestry products industry in Washington State.

Landfill gas plants are typically small in size and the resource potential is very limited. However, the value in landfill gas is not necessarily in the energy. The natural gas produced from the decaying waste in landfills is a significantly more potent greenhouse gas than carbon dioxide. There are a variety of options to handle the gas. It can be captured and marketed as “renewable natural gas,” which should presumably command a premium to conventional natural gas or it can simply be consumed on-site and converted into a less potent greenhouse gas. Preventing the release of landfill gas in the atmosphere represents a carbon reduction and certain landfill gas facilities in the U.S. are certified to sell carbon offsets.

The IRP team constructed a model that incorporates the main cost variables of electric generators and outputs into a single metric: levelized cost of energy (LCOE). It is the per-unit cost of building and operating a power plant over its lifecycle, in constant dollars. It is an assumption driven model, and changes to any one assumption can significantly change results. One of the key variables is capacity factor. For a combined cycle natural gas plant, which currently represents the least-cost available resource to build in the region, has an assumed capacity factor of around 80 percent. That number was chosen because it represents how often a plant is available to generate electricity. With that assumption, it has an estimated levelized cost around $43/MWh. Higher capacity factors translate to lower levelized costs, as sunk costs can be spread over a greater amount of energy. Recent history, however, shows that capacity factors for fossil fuel plants in general, save for peaking plants, tend to be declining. The capacity
factor of the combined cycle fleet hovered between 48 and 56 percent between 2013 and 2015. While a 10 or 20 percent drop in utilization may not materially affect economics, slashing capacity factors in half would raise costs upwards of 35 percent to $57/MWh. One of the questions the team grappled with is how to compare costs: based on how often generation plants are expected to run or how often plants are technically able to run. It is difficult to predict capacity factor since it is often driven by economics. Renewable resources with a zero marginal cost will likely run as long as the wind is blowing or the sun is shining. Other resources with fuel and variable operating expenses will not; rather than insert another variable into this already complex analysis, the IRP team decided to compare resource costs based on technical, rather than economic generation capability.

Data and Results
Fuel prices are a critical variable in calculating the generation cost of natural gas generators. All pricing is based on Henry Hub future settlements. Forward market prices gathered from the Intercontinental Exchange were used for the first five years, as far as the data is provided. Beyond that period, the IRP used a forecast developed by PIRA. To ensure a smooth transition between the different forecasts, the prices were blended together over a period of 3 years, where the first year blend consisted of 1/3 PIRA and 2/3 ICE, the second year 2/3 PIRA and 1/3 ICE, and so on.

Overnight costs of the plants were primarily referenced from the Northwest Power and Conservation Council’s Seventh Power Plan when available, and with the exception of solar power. Cost declines in the solar industry occur at a pace that many times data are outdated by the time a report is published. The IRP team found abundant and updated construction cost data available for PV solar plants and settled on using data published by the DOE. Since costs for generation resources without abundant data could vary significantly from source to source, the IRP team attempted to verify all reference data with at least one other source to ensure accuracy and consistency. The primary and secondary data sources for all the generation resource examined are listed in the table below.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Primary Reference</th>
<th>Secondary Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT</td>
<td>7th Plan</td>
<td>Lazard8</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td>7th Plan</td>
<td>PGE Port Westward 2 Press Release9</td>
</tr>
<tr>
<td>Aeroderivative CT</td>
<td>7th Plan</td>
<td>Lazard</td>
</tr>
<tr>
<td>Solar</td>
<td>US DOE Sunshot Initiative10</td>
<td>Lazard</td>
</tr>
<tr>
<td>Wind</td>
<td>7th Plan</td>
<td>Lazard</td>
</tr>
</tbody>
</table>


The total subsidy a renewable resource receives is a function of the construction start/online date of that specific resource. Wind resources qualify based on construction start date and solar resources qualify based on the operational date. Wind generators also qualify for both the PTC and ITC, but can only utilize one. Developers generally opt to use the PTC, thus the results presented reflect the PTC. The Federal subsidy schedule for renewable resources gradually scales down over the next several years until the subsidies are phased out. To streamline resource LCOE calculations, the IRP team assumed that reductions in the subsidy will be offset by technological gains.

The lowest cost modeled resource alternative is a combined cycle natural gas plant, followed by a slew of renewable resources in order from least cost, landfill gas, wind, biomass, geothermal, nuclear, and solar. Note that these figures were created in a deterministic model and do not incorporate risks and uncertainties. While the construction costs of natural gas, solar, and wind plants are relatively static from site to site, greater uncertainties are ascribed to other generation technologies. Geothermal plants, for example, must be sited within a certain distance of the resource; piping hot water or steam long distances is neither effective nor economical. Geographical, regulatory, and environmental challenges must be resolved, driving up costs, in order for the plant to exist. These technologies also are far less established, with fewer entities manufacturing parts and fewer contractors with sufficient knowledge and development experience. These variables can lead to higher and a more erratic cost distribution, since the market is relatively thin and a single outlier data point can significantly affect the average. The resource options with a high cost risk include biomass, landfill gas, geothermal, and nuclear. The LCOE of solar can also vary significantly, but that is driven by the quality of the solar resource and capacity factor, rather than construction or operational risk. The table below summarizes the assumptions and outputs from the LCOE model. Note that for solar, roughly doubling the capacity factor lowers the LCOE by about 30 percent.

<table>
<thead>
<tr>
<th>Geothermal</th>
<th>Nuclear</th>
<th>7th Plan</th>
<th>EIA</th>
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<tr>
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</tr>
<tr>
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<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>NA</td>
<td></td>
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</table>

The table below summarizes the assumptions and outputs from the LCOE model. Note that for solar, roughly doubling the capacity factor lowers the LCOE by about 30 percent.

<table>
<thead>
<tr>
<th>Units</th>
<th>Aero CT</th>
<th>Recip</th>
<th>CCGT</th>
<th>Wind</th>
<th>Solar (W. WA)</th>
<th>Solar (E. WA)</th>
<th>Biomass</th>
<th>LFG</th>
<th>Geothermal</th>
<th>Nuke</th>
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<td>$/kW capacity</td>
<td>$1.100</td>
<td>$1.300</td>
<td>$1.150</td>
<td>$2.000</td>
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<td>WACC</td>
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<tr>
<td>Inflation</td>
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<td>2%</td>
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<tr>
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<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
<td>$-</td>
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<td>30</td>
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<td>30</td>
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<td>796.0</td>
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<td>983.0</td>
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<tr>
<td>Production Tax Credit</td>
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<td>10%</td>
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<td>10%</td>
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<td>LCOE</td>
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<td>$78.42</td>
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</tr>
</tbody>
</table>

Resources Selected for Additional Analysis

Based on both quantitative and qualitative factors, the following resources were considered by the District’s IRP team to warrant further study.

### Renewable resources:
- Wind
- Solar

### Other resources:
- Combined Cycle Gas Turbine
- Simple Cycle Gas Turbine
- Reciprocating Gas Engine

Solar renewable projects were selected for the initial analysis. Although wind is more costly than several other options, its large scale development and popularity served as the primary justification for further consideration. Coal was excluded from further analysis largely due to the extreme uncertainty in permitting such projects, as well as the fact that coal would violate the legal requirements mandated under SB 6001.
Chapter 6: Macro Utility Environment: The New Status Quo and Utility Industry Disruptions

The energy sphere is evolving as rapidly as any other industry. Since the previous IRP in 2014, the industry has observed changes on all fronts: market, regulatory, and technology. There are several technologies on the development front that have the potential to fundamentally alter the way that society generates and consumes electricity. This section delves into several of the areas that have observed changes on a particularly fast pace and how economics, politics, and science has impacted each of them.

Fracking

The natural gas industry is fundamentally different today with fracking technologies than it was just a decade ago. Fracking unlocked a vast, seemingly infinite supply of domestic natural gas that is well poised to serve the needs of the nation for years to come. Shale gas supplied roughly 5 percent of natural gas production in 2004; that figure grew to 56 percent in 2015. An analysis of the Marcellus and Utica formations illustrate the impact of shale gas. The Marcellus play came online in roughly 2007 and now supplies over 15 percent of domestically supplied natural gas. A few thousand feet underneath the Marcellus formation lies the Utica formation, which has the potential to be a richer, more prolific natural gas reservoir. Daily production from the Utica formation barely registered on reports in 2013, but it now represents 5 percent of total daily domestic gas production. Perhaps most importantly, shale gas extraction has a significant cost advantage over conventional natural gas production.

There are widespread consequences of a large quantity of cheap, abundant natural gas coming online. Most obviously, natural gas prices have declined significantly in recent years. Prices hovered in the $5-9/MMBTU range between 2004 and 2008, prior to intensification of shale gas production (Figure 17). Current natural gas prices are between $2/MMBTU and $3/MMBTU, and expected to remain in that range for the next 5 years. It is more economical to generate electricity from natural gas than coal at these price levels.


Fracking, however, is not without its controversies. There is evidence linking it to an ever increasing frequency of low-magnitude earthquakes in the Oklahoma region, as shale gas production intensifies (Figure 18).\(^\text{14}\)

There are also questions of whether fracking results in groundwater contamination and the extent to which fugitive methane emissions, unaccounted natural gas leaks from the well, contribute to overall

greenhouse gas emissions. New York State enacted a 7 year fracking moratorium in 2015, heeding the requests of several activist groups and even prominent politicians to ban fracking.\textsuperscript{15}

**Coal**

Until recently, domestic electricity was dominated by coal fueled generators since the advent of electricity (Figure 19). Electricity produced from coal decreased from over 50 percent in 2004 to 33 percent in 2015, the same share generated by natural gas.\textsuperscript{16}

*Figure 19: Share of Annual US Electricity Generation by Resource*

The current trend of utilities diversifying away from coal towards natural gas and other resources is not expected to change in the foreseeable future. The current market conditions for coal generators is now less optimistic with more stringent regulations and market conditions favoring other generator types. There are regulatory reasons for the erosion of market share for coal in addition to the economic threat posed by natural gas. New regulations that primarily affect coal generation such as the Mercury Air Toxics Standard, the Cross State Air Pollution Rule, California carbon cap-and-trade, the Clean Power Plan, and Clean Air Rule primarily affect coal generators. Compliance to these rules often times requires expensive upgrades to old plants – or abandoning coal and switching to a cleaner fuel. Cleaner burning natural gas can be an attractive alternative to coal, particularly when there is a cheap and abundant domestic supply available.

**Renewable Resources**


Renewable resources, excluding large hydro, generated about seven percent of the electricity consumed in the US in 2015. While the number is small relative to coal (33 percent) and natural gas (33 percent), the utilization of renewable resources continues to grow along with natural gas while the share of coal generated electricity declines. Wind, solar, and natural gas accounted for nearly all generation capacity additions in the US in 2015, with wind and solar making up a majority of those additions. The share of renewable energy is projected to nearly quadruple to between 23 and 27 percent by 2040. It is notable, however, that the rate of renewable energy adoption has historically been higher than forecasted, while the forecasted costs of renewable energy tend to come in lower than forecasts (Figure 20). There is an observed trend where each new forecast projects a higher renewable growth rate than the previous one.

Figure 20: Evolving US Renewable Generation Capacity Forecasts by Year Through 2032

Wind
In the two years since the last IRP, wind became the lowest cost available resource in certain regions of the US. The average levelized PPA price for wind projects in 2014 was under $25/MWh, inclusive of subsidies. These projects were likely built in the Great Plains or West Texas which possess a high-quality wind resource. Projects outside of these areas with lower quality wind resources will presumably have higher PPA costs. It is nonetheless significant that a resource that, just a few years ago was still far from

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economic viability, is now cost competitive even on an unsubsidized basis, in a low gas and power price environment.

**Solar**

Solar technology is advancing at a pace such that the some of the information disseminated in this IRP will be outdated by the time the report is published. Domestic photovoltaic solar energy has grown an annualized rate of 79 (seventy-nine) percent since the turn of the century. PV capacity grew from four (4) MW in 2000 to nearly 26,000 MW at the end of 2015 (Figure 21).

*Figure 21: Cumulative Annual US Solar Generation Capacity*

PV solar is fundamentally different from all other generating resources in that it is completely modular and can be built to any size, from a system small enough to put on the rooftop of a household to a utility scale plant with an output comparable to a coal plant. Solar energy costs have declined by over an order of magnitude since the turn of the century and nearly 65 percent in the last five years alone. This can be attributed partly to improved manufacturing processes as well as technological improvements which boost cell efficiency. As a result, utility scale solar energy is now cost competitive with other resources in many geographic locations. Rooftop solar is also cost competitive with retail rates in sunnier locations with high retail electricity rates, such as California, the Desert Southwest, and Hawaii. Customers can monetize rooftop solar primarily in two ways. The first approach is to offset consumption. Energy generated onsite at the time of consumption can directly offset electricity usage. Consumption is metered as zero when production equals consumption at any given time, thereby offsetting electricity consumption with a value equivalent to the retail rate. The second method is by utilizing net metering policies. Net metering nets the total amount of energy generated against the amount of energy...
consumed over a predetermined period of time, which is usually a year. Only the “net” energy consumption is billed. Nearly every state, including Washington, mandates that utilities allow net metering.

The net metering remuneration mechanism has recently come under scrutiny as broad adoption of rooftop solar will impact utility finances. While net metering can produce economic benefits to customers with solar, it can also be detrimental to utilities if adopted on a broader scale. Utilities depend on retail revenues to directly fund utility operations, including maintenance, power generation, and administrative functions. A decrease in revenue from one class of customers necessarily results in shifting costs onto another class of customers to make up the revenue gap. Increasing retail rates thereby makes solar more cost competitive leading more customers to install rooftop solar. The crux of the complaint is that the progression of increasing rates to compensate for decreasing retail revenues leads to a downward spiral eventually ending in utility insolvency. Public utility commissions of many states were asked to weigh in on this issue, which did not result in a consensus opinion. The responses ranged from an effective affirmation of the status quo (California) to limiting remuneration to the energy offset and ending net metering (Hawaii).\(^{21,22}\) The only clarity resulting from these proceedings is that net metering is a complex issue and it is important for utilities to adequately structure rates to recover fixed costs.

The intermittent nature of solar energy can also complicate grid management. The production profile of solar energy tracks closely to the daily and seasonal orientation of the sun; this is another way of stating that solar panels only generate energy when the sun is out. The solar fleet within each state tends to collectively come online and go offline. The implication is that there has to be enough dispatchable generation on standby to replace the solar generation when the sun sets or when clouds approach. Much of the backup generation is natural gas fueled. Therein lies the paradox of renewable energy: each kilowatt of renewable generation must be backed up with a dispatchable resource, which is almost universally fueled with natural gas. Recent technological developments, however, are pointing to a possible third option.

**Energy Storage**

The topic of energy storage is explored in depth in Chapter 7: Capacity Requirements, Energy Storage, and Demand Response.

**Electric Vehicles**

Concurrently with the decrease in battery pack costs were increases in the range of electric vehicles. The Chevrolet Volt originally had a battery-only range of about 30 miles. The Nissan LEAF started with a range of roughly 70 miles per charge. One of the concerns users had with earlier models of electric vehicles was range anxiety, the concern that the car would run out of charge before reaching their destination. The


newest generation of electric vehicles starting with the Chevrolet Bolt are estimated to have a range of over 200 miles on a single charge – and roughly equal in cost to the earlier generation EVs.

Continuing the trend of under-forecasting the deployment of new technologies, Tesla originally planned to build 500,000 electric vehicles per year by 2020. That target has since been moved up 2 years to 2018. It’s difficult to predict whether EVs will continue the trend of solar and batteries, with forecasters chronically underestimating consumer adoption or whether it is a trend that will eventually fizzle out.

EVs make up fewer than 500,000 of a total 253 million vehicle fleet in the US. However, the market share of EVs is accelerating in parts of the world, with Norway leading the charge where EVs make up 23 percent of all new vehicle sales. 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. Though gasoline prices in the US have dropped since their 2014 highs, low electricity prices bolster the economic case for EVs. Gasoline futures are hovering around $1.50/gallon, excluding state and federal gas taxes with oil prices near $50/barrel. The average electricity price in the US is $0.12/kWh. An analysis of electric vs. gasoline powered cars indicates that the fuel economy of an internal combustion engine vehicle needs to reach nearly 40 miles per gallon in order to match the economics of an EV (Figure 22, Figure 23).

Figure 22: Internal Combustion Engine Fuel Costs per Mile (excluding Federal and State gas taxes)

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26 Assumptions based on $1.50 wholesale gas which exclude state and federal gas taxes, a national average electricity price of $0.12/kWh as published by the EIA, and an average EV consumption of 3 miles per kWh
Envisioning a future where our current fleet of internal combustion engine vehicles is replaced by EVs still requires a bit of imagination, but it’s a scenario with lasting, positive impacts on the utility.

The widespread adoption of electric vehicles has potential impacts on how and when energy is consumed and has the potential to at least partially offset two looming issues in the utility world. First, load growth in general under-performs its forecasts. Utilities have forecasted higher loads than have materialized since the turn of the decade. Part of this can be explained by implementing conservation measures such as adding insulation to homes. It can also partially be explained through increasing energy efficiency such as converting to LED bulbs or upgrading from electric resistance coil furnaces to heat pumps. While lower energy consumption generally has a positive societal impact, it necessarily harms utility finances. Switching cars to run on electricity rather than gasoline or diesel has the potential of significantly increasing load. The average US household has the potential of increasing its annual energy consumption by 35 percent per electric vehicle.27,28 At a minimum, that represents a significant portion of the demand lost to conservation and energy efficiency. The second problem that electric vehicles can solve, particularly if equipped with bidirectional chargers that can both draw energy from and inject energy to the grid, are potential grid stability issues as more non-dispatchable renewable resources come online. Distilled down to its most basic parts, an EV is a rolling battery that can be used as both an energy sink and source that draws electricity from the grid when it is available and supplies it when demand is higher. Improperly managed, EVs could exacerbate the situation if charging during periods of high demand while providing no benefits to the grid other than an increase in retail sales. Economic signals can strongly

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influence the EV integration path. With the correct incentives, EVs can be used to meet reserve requirements during certain periods of the day.

The topics discussed in this chapter were not inclusive of all developments in the utility and energy sphere, however it was a brief screening of some well discussed subjects today. For evidence of the pace of change within the industry, we can look to our 2014 IRP. Solar was not expected to gain as much market share as it has, coal was still expected to remain as the dominant generating resource, and there was no discussion of batteries or electric vehicles. It would not be surprising if in two years, some of the issues and technologies addressed in this chapter faded away while new ones appear and play an unexpectedly large role in our electric future.
Chapter 7: Capacity Requirements, Energy Storage, and Demand Response

Introduction
An important aspect of a resource plan is an accurate forecast of peak load and a resource plan to meet this load. Since the last IRP in 2014, legislation (EHB 1826) has been added requiring a stochastic look at Energy Storage (ES) and other capacity products to address the integration of variable resources. In the just completed Northwest Power and Conservation Council’s 7th Power Plan (Council or Council Plan), Demand Response (DR) was thoroughly reviewed and determined to be a cost effective resource to meet peak load.

Energy storage and demand response will be reviewed in this chapter in the context of meeting peak load. These resources can be used to make a variable resource firm, either within an hour or across multiple hours. Since the District is not a Balancing Authority, firming within an hour will not be addressed. An attempt will be made to examine firming across several hours.

Peak Load and Capacity Position
As discussed in Chapter 3 the District is surplus energy on an annual load/resource view. Demand, however, is not constant through each hour of the day. This section is a view of the District’s capacity, a more granular analysis of the District’s ability to meet demand on an hourly, rather than annual basis.

Figure 24 charts the daily average temperature vs. the daily average load between 2010 and 2015. In that period, the District has observed several very cold snaps and the hottest summer on record. While periods of extreme heat or cold are both accompanied by higher loads, higher load periods come more frequently during the winter rather than the summer. This is consistent with most utilities on the west side of the Cascades, with cool winters and relatively mild summers. Loads are generally the lowest during periods when the temperature is between roughly 50°F and 60°F.
Projecting generation capacity with a predominantly hydro utility has its challenges in that there is always a concern regarding fuel availability. On a firm basis, the District currently projects a winter peak generation capability of 770 MW and 680 MW of peak summer generating capacity. These figures were developed assuming adverse hydro conditions, with the Slice system peaking at 10,500 MW in the winter and summer. The District’s peak generation capacity was derived from taking the actual seasonal Slice system observations during atypical weather periods of the last 5 years. The IRP team thus turned to the historical dataset to inform its future peak generation capacity, which contained periods of both very hot and very cold weather during drought conditions. This estimate also excludes wind resources, which cannot be relied upon to generate electricity on demand and as a general rule do not generate electricity during extremely hot or cold periods. Compared to the highest peak demand and average heavy load hour loads observed in the last 5 years of 792 MW and 667 MW, respectively, there are a handful of hours when demand exceeds the District’s resources on a planning basis.

Figure 25 displays a theoretical net position of the daily peak demand hour that was calculated by applying the District’s projected firm peak generation capability to the actual loads observed between 2012 and 2015.
The District does not appear to have capacity shortages in either the winter or summer. There is only one day in the four year period that failed this analysis, and the deficit on the peak hour of that day was less than 20 MW. This capacity shortage can be filled through fixed price power purchases from the market much more economically than procuring a physical asset considering the frequency of the event. The costs and risks associated with a capacity shortage, along with available strategies to manage these situations are discussed later on in this document.

Based on a capacity study completed for this IRP, Figure 26 estimates the annual peak hourly loads and resources throughout the IRP study period.
Figure 26: Annual Peak Hour Load/Resource Balance through 2036

Peak Load Analysis

**Peak load definitions:** Peak load and the capacity products and resources to meet peak load in the context of a resource plan can be defined in many ways and it is important to agree on definitions. The following will describe the different definitions and will recommend a definition to use in this plan.

**Within hour peak load:** This is the highest instantaneous and 5/15/30 minute integrated peak load that occurs within the month or year. BPA Transmission Service’s (BPAT) as the Balancing Authority (BA) is the entity obligated to meet this peak load. A slice customer sets aside and is not able to access its share of about 900 MW to 1,300 MW of slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. Examples of revenues are regulation, imbalance charges (energy and generation imbalance and Dispatchable and Variable Energy Resources Balancing Service, Dispatchable Energy Resource Balancing Service (DERBS) and Variable Energy Resource Balancing Service (VERBS) charges) and Contingency Reserves. The slice customer receives its share of these revenues as an offset to the Composite Charge. By virtue of the Slice customer contractually giving up its share of capacity for within hour services, and purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves), the customer has handed over its obligation for these services to the BA and should not be including capacity for these services in its capacity planning.

BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output, INC), or a decrease in net load (requiring these resources to decrease, DEC). Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP. It should be noted that the regional Energy Imbalance (EIM) activities are focused on this time period.
**Hourly peak load:** This is the largest 60 minute load that historically occurs or is forecast to occur during a year, season, or month. It can be defined as the largest actual hourly load, the largest actual load that has occurred during a historical period, a forecast of the hourly load under extreme conditions, or the expected hourly load (i.e. hourly load expected to occur less than a given percentage of the time, for instance, less than 95% of the time). It is typical to identify the largest expected winter and summer hourly load for resource planning purposes (usually by choosing from actuals from a recent year, or a series of years or an extreme forecast). Figure 27 display the winter and summer hourly load for the summer and winter peak days from November 2010 through December 2015. The highest hourly winter peak has been 831 MW and highest summer peak has been 641 MW.

**Figure 27: Historical Annual Hourly and Average HLH Peak Loads**

<table>
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<tr>
<th></th>
<th>Hourly Peak</th>
<th>Average HLH</th>
<th>50th Percentile Avg HLH</th>
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<td>624</td>
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<td>719</td>
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<tr>
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<td>Summer 15</td>
<td>641</td>
<td>555</td>
<td>561</td>
<td>608</td>
<td>615</td>
</tr>
<tr>
<td>Winter 15</td>
<td>753</td>
<td>610</td>
<td>602</td>
<td>677</td>
<td>689</td>
</tr>
<tr>
<td>All Data</td>
<td>831</td>
<td>594</td>
<td>580</td>
<td>676</td>
<td>717</td>
</tr>
<tr>
<td>All Winters</td>
<td>831</td>
<td>632</td>
<td>622</td>
<td>708</td>
<td>735</td>
</tr>
<tr>
<td>All Summers</td>
<td>641</td>
<td>564</td>
<td>561</td>
<td>603</td>
<td>614</td>
</tr>
</tbody>
</table>

**Heavy load hour peak load:** This is the largest average load during HE 7-22 on a NERC defined peak day that historically occurs or is forecast to occur during a time period. The time periods are the same as hourly peak load as is the discussion of largest and expected. The highest HLH winter peak has been 656 aMW and highest HLH summer peak has been 575 aMW.

**Determination of Peak Load for Resource Planning**

There are several standard practices to determine which peak load to use in resource planning. First one must determine whether to plan to serve the one hour peak load or the HLH peak load. There are reliability issues and financial issues. For a utility embedded within the BPAT BA, there is not currently a requirement to demonstrate Resource Sufficiency (RS) on a forecast basis. The only requirement is to enter the hour of delivery with scheduled resources sufficient to meet forecasted load. There is not even a required methodology to forecast the hourly load.
Since there is not a local reliability issue associated with not having resources available to meet an hourly peak load, and there has not been a cost effective resource option to meet that one hour peak load, utilities often procure resources (or forward market products) to meet the HLH peak load and just depend on the market and the BA for the one hour peak load. Demand Response (DR) and Energy Storage (ES) are potential products for meeting some of the peak load and will be analyzed for their cost effectiveness as compared to the market along with conventional peaking resources.

A second question is whether to use extreme, expected, or expected with an adder in the determination of peak load. Many reliability organizations and organized markets have an RS requirement based on “expected” peak load times a multiplier. The multiplier suggested for a LSE is 5%.

Another methodology is to use modeling techniques to determine a projection of the HLH and hourly peak load under expected and extreme weather conditions. Often times both approaches yield similar values.

**Hourly peak load determination utilized by Organized Markets/Regional Reliability Organizations (RRO):**
Organized markets/RROs typically employ a Resource Adequacy (RA) requirement on Load Serving Entities (LSEs) within its footprint. The RA metric will contain rules for determining peak hourly load and resource outputs. A survey of markets found the following requirements for determining peak load:

- **Western Electric Coordinating Council (WECC):** Forecast peak hour load increased by 18% to cover; contingency reserves 6%, regulation 5%, 4% for additional outages, and 3% for temperature variation.

- **Northwest Power Pool (NWPP):** Contingency and Regulation 7-8%, additional or prolonged outages 3-10%, and 1-10% to cover temperature (assume about 5% for this portion), economics, new plant delays resulting in an 11-28% requirement.

- **California Independent System Operator (CAISO):** Forecasted hourly peak loads are increased by 15%. CAISO doesn’t break out the load variation portion.

- **Midcontinent Independent System Operator (MISO):** Forecasted coincidental hourly peak loads are increased by about 8% for load variation and 7% for outages (contingencies).

There does not seem to be a single standard to use in planning for load variations. However, it does appear that a general planning criteria for variation in load is in the 3-8% range. The other components of the standards are for contingencies, which as discussed above is not the requirement of the LSE.

**Approach used for peak load determination:**

1. Examine Nov-Feb and June-August actual hourly and daily HLH load for 2012-2015 and determine the 95th percentile. Multiply the winter value by 1.05 and the summer value by 1.05.
2. Establish this value as expected winter and summer hourly and HLH peak load for the 1st year of the IRP (2016).
3. Use the annual growth in energy load as the annual growth rate for future years.
Figure 28: Historical Peak Hourly Load Statistics

<table>
<thead>
<tr>
<th>Load Scenarios (MW)</th>
<th>50th</th>
<th>95th</th>
<th>1.05x95th</th>
<th>99th</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer HLH</td>
<td>579</td>
<td>607</td>
<td>637</td>
<td>615</td>
<td>617</td>
</tr>
<tr>
<td>Summer Peak</td>
<td>597</td>
<td>627</td>
<td>658</td>
<td>636</td>
<td>641</td>
</tr>
<tr>
<td>Winter HLH</td>
<td>638</td>
<td>708</td>
<td>744</td>
<td>732</td>
<td>756</td>
</tr>
<tr>
<td>Winter Peak</td>
<td>669</td>
<td>743</td>
<td>780</td>
<td>770</td>
<td>792</td>
</tr>
</tbody>
</table>

Figure 29 displays the expected resource output during summer and winter hourly peak and HLH. The Slice values were determined by TEA planning staff.

Figure 29: Expected Peak Hourly Resource Generation

<table>
<thead>
<tr>
<th>Resources (MW)</th>
<th>Slice</th>
<th>Block</th>
<th>Swift</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer HLH</td>
<td>320</td>
<td>250</td>
<td>77</td>
<td>5</td>
<td>652</td>
</tr>
<tr>
<td>Summer Peak</td>
<td>400</td>
<td>250</td>
<td>77</td>
<td>5</td>
<td>732</td>
</tr>
<tr>
<td>Winter HLH</td>
<td>420</td>
<td>285</td>
<td>77</td>
<td>5</td>
<td>787</td>
</tr>
<tr>
<td>Winter Peak</td>
<td>420</td>
<td>285</td>
<td>77</td>
<td>5</td>
<td>787</td>
</tr>
</tbody>
</table>

The District at the moment is expected to be able to meet its summer and winter capacity needs.

Figure 30 overlays projected peaking resource with peak loads in 2025, assuming that the peak demand growth is equal to the AAGR of 0.38%. The planning scenario used is the 95th percentile multiplied by 1.05 case. For 2017, there is currently 70 MW of surplus capacity forecasted for the summer. However, the winter capacity is currently equal to peak demand. By 2025, the winter capacity deficit is forecasted to grow to 20 MW in the capacity planning scenario.
Resources to Serve Peak Load

There are several approaches to the determination of a resource mix to serve peak load. Each of these will be analyzed with its pros and cons and 3 preferred sets will be identified for further stochastic analysis.

Buy whatever is needed above the IRP preferred resource mix: The IRP will determine resources needed to meet annual energy load over multiple years. Rather than procuring additional resources to meet the peak load value, one option is to continue current practice to buy from the market as needed. This has the advantage of only buying what is needed, without a resource sitting idle much of the year. This approach includes the use of buying daily physical HLH call options in advance of the start of a winter or summer month. Hourly peak load needs would be bought in the real time market, or purchased ahead of the day of flow and any surpluses would then be disposed of in the hourly market.

With both forward natural gas and power market prices very low, this option is likely to be found to be the least cost in the screening process. It assumes that market power will always be available. There are regional indicators on whether this is a good assumption. The Council performs a Resource Adequacy Assessment (RAA) which determines a Loss of Load Probability (LOLP). The 2015 analysis indicated a regional LOLP of less than 5% through 2021, when several large coal plants are scheduled to shut down. The analysis provides LOLP for both summer and winter and includes some imports from California.
Pacific Northwest Utilities Conference Committee (PNUCC) Northwest Regional Forecast of Power Loads and Resources study\(^\text{29}\) also indicates in the chart below a greater need for capacity in the winter months but capacity needs are more than covered by firm resources, and Northwest IPPs thru 2020 but then fully mitigated by market imports through 2021. If average hydro conditions are included then the regions has no capacity constraints for many years after 2021 due to the additional 4,000+ MW of generation (Figure 31).

**Figure 31: PNUCC Northwest Regional Forecast of Peak Loads and Resources**

Figure 32 notes that looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply. The starting point for the 2016 annual energy requirements forecast is down nearly 1,000 MW from the 2012 Forecast. This trend is not found in the summer peak forecasts which continue to trend as expected.

**Figure 32: PNUCC Annual Firm Requirements Forecast**

The “BPA 2015 Pacific NW Loads and Resources Study” also known as the White Book listed key assumptions including the below:

• Lower load estimates due to slower than anticipated economic growth recovery from 2008 recession.
• Lower DSI load obligations from 300 MW to 75 MW.

The above BPA assumptions and their continued emphasis to aggressively meet and exceed regional conservation targets along with growing interest in demand response all contribute toward further mitigating future capacity needs.

**Buy forward (5 year +) physical daily fixed-price call options or daily heat rate (HR) call options:** Electricity call options are a possibility and can be procured as physical or financial products. The LOLP should provide some insight into whether a physical option is desired. These options could be for the entire HLH deficit or some portion, with the balance left in the short term markets.

There is likely an interesting dynamic at play here. In the short term the LOLP is likely to be 5% or less, with studies showing a future state when it begins to increase. Major Northwest IOU’s will likely monitor this dynamic and begin to plan new resources for the future periods when LOLP is higher. The District may find that the LOLP is never greater than 5% in the prompt year or prompt year plus one to five. Therefore, the District could plan to put in place forward call options for 3-5 forward years, but never need to actually purchase the product if it finds the LOLP moves back to 5% in this medium term.
Demand Response: DR is best suited for meeting the hourly peak load deficit. The 7th Plan determined the following results for various DR programs. It is assumed that DR could be implemented at the District for these costs (Figure 33).

Figure 33: 7th Power Plan Demand Response Cost Bins

Energy Storage: Advancing energy storage technology to the point where it can economically be used as the backup resource to renewable energy could solve the current paradoxical situation. The storage system would be charged using surplus renewable energy, or during periods of low demand and released when demand increases, supply decreases, or both. Current research is diversified among many different technologies which explore storing potential energy in flywheels, compressed air, even in trains perched at the top of a hill. The technology poised to dominate the market, at least in the near term, is battery storage.

Battery systems are not a one size fits all solution and the system design varies significantly depending on its desired function, whether it’s for renewable integration, peaking, frequency regulation, or transmission congestion.\(^\text{30}\) Building a battery system to absorb excess renewable generation for later use

\(^{30}\)“Lazard’s Levelized Cost of Storage Analysis Version 1.0.” Lazard. Web. 11 June 2016
requires more infrastructure than a battery system used for short-term frequency response. Imagine an island grid powered only by solar and batteries. The battery bank will require a capacity that can store enough energy when the sun is shining to meet its demands at night. If that island grid also had backup generators on standby as a part of its generation mix, those could increase production when a cloud unexpectedly parked itself over the sun. The battery system then would be relied on for a much shorter burst of energy to maintain grid stability until the generators take over. The costs for the first option will be greater, perhaps even significantly, than the second option. Battery technology, however, is evolving at a rapid pace. The development of battery packs in recent years can be attributed primarily due to investments into research and development from the auto industry. The solar industry utilized technology from the semiconductor industry in its evolution earlier in the century and the energy storage sector is expected to leverage battery technology from other industries in building their own.

The cost of battery packs declined from $1000/kWh in 2010 to $350/kWh by 2015 (Figure 34).31 Battery capacity for the upcoming generation of electric vehicles dropped to $145/kWh, arriving at that price point 15 years ahead of current forecasts.32,33


That amounts to an 85 percent drop in six years, following the general cost curve of wind and solar: exponential cost declines continuously exceeding the pace of forecasts along with higher than forecasted rates of adoption. Whether and how long this trend will keep its pace is unknown. However, it is relatively certain that technology will continue to advance and costs will keep declining.

Tesla is one company that is leveraging their experience in the EV market to enter into the residential market. Most notable for manufacturing EVs, Tesla is also offering lithium-ion battery home and utility-scale energy storage systems at a cost between $350 and $600/kWh, excluding installation.\(^\text{34}\) Energy storage systems are costlier than the batteries alone due to balance of system costs that include bi-directional inverters that allow the two way flow of energy, software, and other integration costs to ensure seamless operation regardless of energy source, whether it’s from the grid, solar panels, or battery packs. There are few case studies available to determine the actual cost of battery storage systems. Puget Sound Energy’s Glacier battery storage pilot project tied several thousand lithium ion batteries together and created a 4.4MWh system with a 2MW instantaneous power delivery rating. The total costs of the system are unclear, with at least $3.8 million of it funded by grant from the Washington State Clean Energy Fund plus additional investments from PSE. Based on the information available publicly, total system costs could range from $860 to $2200/kWh capacity.

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Storage is estimated to cost a minimum of $200/MWh on a levelized basis, reaching as high as $1000/MWh. An analysis of historical wholesale market data reveals that there are very few hours and even fewer days where batteries are cost competitive (Figure 35).

Figure 35: 2012-2015 Hourly Mid-C Prices

Wholesale market prices would need to sustain levels of $200/MWh or enter periods of extreme volatility in order to make an economic argument for the inclusion of battery storage with costs at this time.

The IRP team conducted a stochastic analysis of market prices under various gas price, carbon price, load growth, and carbon restricted scenarios. The results indicated that energy storage, in its current form, would not be economically viable within the study period. The caveat, though, is that energy storage technology is still immature; the technology will not remain static, it will only improve, and costs will inevitably decline. At this moment though, there are few data points available to extrapolate out a forecast of when energy storage will become viable. If the reports are correct, though, costs will probably need to decline by nearly an order of magnitude to compete on the wholesale energy markets.

Simple Cycle Combustion Turbine: Another resource for meeting peak load needs is a simple cycle combustion turbine (CT). A CT has the ability to start on a shorter notice than a combined cycle turbine and has less required up and down time. Given this flexibility it can be used to meet peak energy needs. The analysis in the BPA rate case will be used as a proxy for the cost of a CT (Figure 36). Note the capacity cost is $118.59/kW/year or $13.54/MWh.

35 ibid
The District’s current Slice/Block and Swift assets have the ability to ramp up to meet its load during high demand periods. The District is not expected to have any capacity issues in the near-term, but winter capacity deficits of 20 MW are projected by 2025. Procuring traditional peaking assets comes with significant costs. However, technological advancements are leading to cost decreases for emerging technologies. The IRP team will analyze the costs, benefits, and risks of procuring a peaking asset when capacity shortages appear, by 2025.
Chapter 8: Market Simulation

This chapter provides an overview of the methodology and assumptions used to create the long-term market simulation used in the IRP. The values produced are integral to the resource evaluation process as they describe a resource addition’s expected performance and risk. Each potential resource is added to the District’s existing portfolio and its cost is measured on a net present value basis over multiple simulations of electricity price.

Approach
The electricity price simulation is created by several fundamental models working in concert. Figure 37 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. Examples include CO2 penalty and regional renewable portfolio standard implementation. 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 20 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.

IRP Model Structure
The main tool used to determine the long-term market environment is AURORAxmp also referred to as “Aurora”. Developed by EPIS, Inc., Aurora simulates the supply and demand fundamentals of the competitive physical power market, and ultimately produces a long term power price forecast. Using factors such as the performance characteristics of supply resources, regional demand, and zonal transmission constraints, Aurora simulates the WECC system to determine how generation and transmission resources operate 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 long-term deterministic view of resource additions
2. Establish an expected long-term forecast price
3. To analyze corresponding stochastic results of market behavior around the above expected price forecast
4. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions

The District created forecasts of key variables, such as regional load growth rates, 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. Much of the analysis in this IRP focuses specifically on the Northwest region, specifically Oregon, Washington and Idaho. Even though the IRP forecast focuses on the Mid-C electricity market, it is important to model the entire region. This is because fundamentals in other parts of the WECC exert a strong influence on the Pacific Northwest market. To create a credible Mid-C forecast it is imperative that the economics of the entire western interconnect is captured.

**Long-Term Fundamental Simulation**

A vital part of the long-term market simulation is the capacity expansion analysis. The IRP utilized AURORAxmp to determine what types of power plants will likely be added in the WECC over the next 20 years. To arrive at an answer requires an iterative process. In the first step, Aurora was programmed to run a 20 year dispatch study assuming that no new plants are built in the WECC. Over the course of the
study period WECC loads escalate which cause planning reserve margins to fall and prices to rise. In the second step Aurora adds resources progressively with load growth. The resources that are chosen are the best economic performers – i.e. provide the most regional benefit for the lowest price.

**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 units), and capacity factor (wind and solar units). Based on the parameters outlined above, Figure 33 illustrates the expected new resource expansion and retirement through 2036 throughout the entire western interconnect region.

RPS requirements are one of the main drivers of new resource expansion over the next decade, as utilities develop mainly new wind and solar resources to meet state requirements. Renewables, namely solar and wind, make up the majority of capacity additions over the study period. There is a significant expansion of renewables through 2021 when federal subsidies are still in effect, followed by a large increase in combined cycle natural gas plants thereafter.

*Figure 38 - Forecasted WECC Generation Capacity Additions through 2036*

Throughout the WECC region coal output is forecasted to decline substantially, with new coal plants not being developed due to federal emissions regulations. By 2026 9,248 MW of coal will be retired. The planned retirement of an additional 615 MW from the coal fired Colstrip units 1 and 2 in Montana by
2022 was announced after the analysis was already completed. The generation lost as a retirement of the plant will need to be replaced, presumably by wind, solar, natural gas, or a combination of all 3 in order to progress to Clean Power Plan compliance. The Colstrip retirement represents a small fraction of the approximately 30,000 MW of generation capacity in the region. As a result, it is unexpected to have a significant effect on market heat rates and prices. Nuclear output will decline as aging units are taken offline, and hydro output will stay the same. The majority of the increasing load will be met with wind, solar, combined cycle natural gas plants, and to a lesser extent simple cycle natural gas plants.

**Figure 39 - Forecasted Pacific Northwest Generation Capacity Additions through 2036**

Within the Oregon-Washington-Idaho region hydroelectricity will stay the largest single generating resource through the study period, with no projects being built or retired. All coal plants in the region are projected to retire by 2026.

Wind remains the renewable choice for fulfilling RPS requirements, although solar is quickly becoming a very significant component. The cumulative renewables expansion in the Pacific Northwest over the study period is 17,200 MW, of which 9,200 MW are wind and 8,000 MW are solar. A few years ago this increase in renewables would have been largely wind, as solar was not projected to be cost competitive with wind. A significant portion of the renewables build out over the study period is to meet an increase in Oregon’s RPS requirements, which targets 50% renewables by 2040.

Following the significant build out of wind and solar through 2021, combined cycle natural gas plants make up the bulk of new generating capacity to meet increasing demand.

The story is similar in California, although there are substantial retirements of once through cooling units through 2020, which are replaced with renewables generation. Recently, Pacific Gas and Electric announced the retirement of the Diablo Canyon nuclear facility, this study was performed prior to this announcement and as such this asset is included in this analysis.

Unlike the Northwest, the majority of renewables generation expansion is from solar. Further, the expansion of solar generation continues through 2029 when the addition of simple cycle gas plants become the preferred resource.

**Principal Assumptions**
This section reviews the key assumptions that were used in the capacity expansion study as well as the stochastic simulation.

**WECC Load**
Demand escalation forecasts for zones in the WECC region are based on WECC’s Transmission Expansion Policy and Procedure Study Report\(^{37}\) and are provided in the Aurora database. Based on these forecasts, the District expects overall load in the western interconnect will grow by 0.5% annually over the course of the study period. Increases in energy efficiency, behind the meter generation, slower economic growth, and decreased population growth contribute to less aggressive load growth when compared to the

\(^{37}\) [https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_Stu](https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_Stu)
historical average. The load growth assumptions for the WECC zones discussed in this IRP are shown below in Figure 41.

Figure 41: Northwest & California Regions Load Growth Assumptions through 2036

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 2015 Long Term Reliability Assessment, outlined below in Figure 42.
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 43 provides a summary of WECC states renewable standards. 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. Both Oregon and California have higher RPS requirements at 50%, California’s target is 2030 whereas Oregon’s is 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 AURORA long-term capacity expansion model. This enables more consistent economic evaluation of different renewable resource additions.

Natural Gas Price Simulation
Natural gas prices are a key factor in the market simulation. It is challenging to forecast prices over a 20 year time period as natural gas prices are inherently volatile and market dynamics are constantly changing. As a result, the expected scenario was determined by combining several data points. The first part of the price curve uses Henry Hub forward pricing data, as marked on the Intercontinental Exchange, through the year 2020. From the years 2021 -2028 prices are the mean of Henry Hub forward prices and a long-term price forecast from PIRA. For the remainder of the study period the PIRA forecast is used. Figure 44 displays the natural gas prices used for the study.

**Figure 44 - Natural Gas Price Assumptions**

The District used a proprietary model to develop natural gas distributions for use in stochastically modeling electricity prices. The model is a statistical model which uses historical Henry Hub prices to generate an overall distribution of gas prices, which are presented below in Figure 45.
The middle trace represents the average of all of the iterations. The upper and lower traces represent the 90th and 10th percentiles, respectively. A multi-factor mean-reverting Monte Carlo process is used to simulate the volatility of daily spot gas prices, which is then used in a Heston Model to generate prices. The model is seasonally adjusted to reflect historic seasonal trends in price and volatility, and is normalized to forward prices and a PIRA forecast as discussed above. The IRP team ran 79 iterations of this model, one for each corresponding BPA water year, each generating daily spot gas prices through 2036, which were input into Aurora.

**Carbon Penalty Simulation**

There is a high level of uncertainty regarding the regulation of CO₂ emissions, as well as the structure and creation of carbon trading markets. 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 Colombia, Manitoba, Quebec and Ontario. British Columbia and Alberta have carbon taxes in place, which are included in the market simulation. A large amount of the surplus generation from the Pacific Northwest is sold in California. However, there is currently proposed legislation in Washington and Oregon to create either a carbon trading market or carbon tax. Either way, this will be something to closely monitor over the next couple of years.

In addition to the above the current proposed Clean Power Plan (CPP), which is further discussed in Chapter 4: Policy & Regulation, is included as a baseline assumption in the market simulation. The market simulation assumes a WECC-wide mass based implementation plan.

Figure 46 shows the assumed carbon prices for the market simulation with the carbon penalty assumption for a WECC-wide mass based CPP. The carbon penalty assumption is the price of carbon, in
70/ton, that is required to reduce carbon emission levels to targets as specified by the CPP. As can be seen, the CPP is a “non-binding” constraint to the market simulation model implying that the CPP does not have an impact on WECC generation assuming a WECC-wide mass based implementation. This is due to the aggressive Renewable Portfolio Standards set by California, Washington, and Oregon which already require a high level of carbon free generation.

Figure 46: Carbon Penalty Assumption and CPP Results

Hydroelectric Generation Simulation

Hydro power currently accounts for approximately two-thirds of electricity generated in the Northwest U.S., and one-quarter of generation in the Western Interconnect. One of the challenges of hydro generation is its variability and uncertainty. Yearly hydroelectric output depends on a number of variables, including snowpack and environmental regulations. To capture this uncertainty in the market simulation modeling the District used historical hydro generating data as an input for the stochastic model. Figure 47 illustrates the hydro generation assumption used in the price simulation. The solid blue line represents the expected generation level, the dark-blue shaded region represents the 25th and 75th percentiles, and the light-blue shaded region represents the 95th and 5th percentiles, respectively.
Heat Rate Simulation

Heat Rate is a measurement that calculates the efficiency of a generator. It refers to the amount of energy in million BTU a generator requires to produce one megawatt-hour of electricity. Natural gas generators are commonly used to provide incremental energy when it is needed, especially in the summer and winter where natural gas generation sets the marginal clearing price of electricity in the market. The unit of measurement for this is the market implied heat rate, which can be calculated by dividing the power price by gas price. Generators with a lower heat rate than the market heat rate can generate power at a lower cost than the market.

The capacity expansion analysis provides a forecast of what resources will be added in the WECC over the next 20 years to meet forecasted load obligations. These hypothetical resources are added to the existing resource stack to create a 20 year “stack forecast”. This hypothetical supply stack is the foundation of the market heat rate simulation. Once these modifications are programmed into Aurora, all of the major factors are varied using Monte Carlo simulation. Major factors include WECC loads, WECC hydro generation, fuel prices, and CO2 penalties. The result of the simulation is represented by Figure 48. Each dot represents an individual month from the simulation. The middle trace represents the average of all of the iterations. The upper and lower traces represent the 95th and 5th percentiles, respectively. Market heat rates are expected to stay relatively flat, although volatility will change slightly over time.
Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained over multiple iterations of Monte Carlo analysis. In the Mid-C region, prices have
historically been among the lowest in the country due to the abundance of cheap hydropower. Hydro output is not expected to increase throughout the period of this study, meaning that more expensive wind and natural gas generation will be used to meet increased demand. Figure 50 shows the simulated Mid-C power prices. Each dot represents an individual month from the simulation. The middle trace represents the average of all of the iterations. The upper and lower traces represent the 95th and 5th percentiles, respectively.

Figure 50 – HLH Mid-Columbia Price Simulation
Scenario Analysis

In addition to the above baseline scenario two 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 changes 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 two alternative scenarios include:

1) Low Load Growth Scenario: A reduction in the load growth assumption for the entire WECC region. This is a gradual reduction from the average annual growth rate of 0.5% year-over-year to a negative growth rate of -0.5% year-over-year, on average across the entire study. The first alternative scenario, reduced load growth, 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 downward revision in load forecasts.

2) WA State Carbon Tax: The second alternative scenario assumes a carbon tax for the state for Washington State. There is currently proposed legislation (see Chapter 4: Policy & Regulation) that would impose a carbon tax on all large stationary emitters of CO2. This scenario, a carbon tax in Washington State, considers the impacts of proposed carbon legislation on resource mix and market dynamics. The assumed carbon price for this scenario is $25/ton on average over the study period, starting at $15/ton in 2017 rising ratably year-over-year over the study period.
Figure 52 below shows the projected resource additions through time under the Low Load Growth scenario. Figure 53 below shows the projected resource additions through time for the WA Carbon scenario.

Figure 52: Low Load Growth Scenario Projected Annual Resource Additions Through Time
About 5,600 MW less natural gas generation is built out over the entire study period under the Low Load Growth scenario. However, 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.

Under the WA Carbon Tax scenario the resource build out is similar to the Base Case scenario, but with a little less CCCT generation in California and a little more CCCT generation in the Northwest. The impact of a WA carbon tax is much more relevant for market prices and heat rates.

The effects on power prices are illustrated below in Figure 54. As expected the WA Carbon Tax scenario increases the forecast market price by about $2.65/MWh on average over the study period. The resource stack in the baseline scenario and WA Carbon Tax scenario are relatively unchanged, so the increase in price is largely a result of marginal natural gas units paying the associated carbon costs and a significant amount of the generation fleet, such as hydro and wind generation, are exempt from carbon costs.

The Low Load Growth scenario has a significant impact on power prices. The average power price for this scenario is about $4.54/MWh lower on average over the entire study period, and growing to as large as $14.45/MWh by 2036. It also presents a different resource stack by displacing higher cost natural gas generation and meeting load growth with a continued build out of renewable generation.
Figure 54: Mid-C Power Price Forecast in Base, Low Load, and WA Carbon Scenarios

Figure 55 displays the forecasted implied heat rates (calculated as $/MWh Power Price divided by $/mmbtu natural gas price) for all three scenarios. Similar to the power prices, the heat rates under the WA Carbon Tax scenario are higher. The marginal natural gas units are paying the associated carbon costs, pushing up the marginal cost of market clearing price, while the resource stack remains relatively stable. The Low Load Scenario produces heat rates that are decreasing over time, significantly lower than the two other scenarios.
The scenario analysis provides 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. Whereas the baseline market simulation model assumes a given load growth and no WA Carbon Tax, the effects of changing load growth or including a carbon tax can be observed through scenario analysis.
Chapter 9: Risk Analysis

The IRP staff constructed a long term integrated financial and energy position model to forecast the District’s annual net power cost for the duration of the study period. The financial model used the results from previous sections, including forecasted loads, simulated hydro generation scenarios, forecasted output from generation resources, power price scenarios, regulatory scenarios, and forecasted generation resources. The outputs from the model measured the impact of these different scenarios in a single metric: the average cost per megawatt-hour of load served in 2016 dollars.

With expected load growth, the District is projected to have sufficient resources to meet its annual energy needs in critical hydrological conditions through the entirety of the study period (Figure 56, Figure 57). Though the District is projecting a handful of large industrial loads to come online within the study period, those customers are expected to secure and/or locate and identify resources to serve their load.

Figure 56: 20 Year District Loads and Resources in Critical Hydro Conditions
The vast majority of years will also result in better than critical water conditions, resulting in even larger energy surpluses. Under average conditions, the District is projected to carry an average surplus of over 100 aMW throughout the entire study period (Figure 58, Figure 59).
Figure 58: 20 Year District Loads and Resources in Average Hydro Conditions

Figure 59: Annual Energy Net Position in Average Hydro Conditions
The District may be surplus energy, however, it will face REC shortages in 2026, after the RPS increases from 9 percent to 15 percent and the annual carryover from surplus RECs are depleted (Figure 60, Figure 61).

**Figure 60: 20 Year Annual RPS Supply and Demand**
The initial spike in RECs represent those that were carried over from the previous year. Beginning in 2026, the REC deficit averages 38,000 RECs per year, which translates into 4.3 aMW of renewable generation.

On a planning basis, the District is not projected to have any surplus winter capacity beyond 2017, with deficits expected to grow at an average of 2-3 MW per year. Summer capacity is expected to be able to meet demand.

The District’s resource acquisition is driven by the need to fulfill I-937 requirements and growing capacity deficits rather than filling any energy deficits. However, there are alternatives other than outright procuring physical assets to address these shortfalls. For example, the District can meet its RPS by purchasing the renewable attributes of a renewable resource in the form of RECs and meet capacity deficits through short-term market solutions.

The forecasted REC deficits will likely materialize regardless of load growth, since the RPS itself is becoming more stringent. Capacity deficits, however, may or may not materialize depending on load growth. The utility industry has been in a trend of smaller load growth. If this trend continues, capacity deficits will be smaller and it is possible that these deficits will be erased completely.

An unconventional risk that the IRP team decided to model is the catastrophic loss of a power plant. While this is certainly a low probability event, it is not unprecedented. In 2002, Swift 2 suffered a catastrophic failure resulting in the plant being offline for 4 years before it was rebuilt. This risk assessment analyzed the total loss of the Harvest Wind project beginning 2017 for the duration of the study period, assuming that the District was still responsible for its portion of capital, but not O&M costs. The goal of this scenario analysis was to subject the portfolio to a sudden and complete loss of an asset to...
test the durability of the District’s portfolio. The analysis determined how such an event impacted the District on an energy, capacity, and financial basis.

The IRP staff analyzed 4 portfolios, with each portfolio comprised of a different resource mix to determine the costs and risks associated with each portfolio. IRP staff also took into consideration that development potential for certain resources are finite. A natural gas peaking plant can only be reliable if there is available pipeline capacity to guarantee gas flows to the plant. Biomass plants should be co-located with industrial plants that produce biomass to minimize transport costs. Considerations for wind and solar plants are less binding, as access to those resources are more widely available.

The IRP staff screened 11 different resources but constructed portfolios with only 3 of these resources. The other resources were eliminated from contention based on technical, economic, and political factors. Each portfolio was structured to accomplish different goals. Portfolio 1 was established as the baseline, “continue the status quo” portfolio in which the District does not acquire any resources and relies on the market to fill any energy, capacity, or REC deficits. Portfolio 2 fulfilled the capacity needs of the District, and relied on the market to fulfill any REC deficits. Portfolio 3 examined the impact of adding a renewable resource to cover the coming REC deficit. Portfolio 4 analyzed the impact of the sudden loss of the Harvest Wind plant, as a stress test of the District’s ability to weather unexpected, but significant events. Figure 62 displays the capacity addition schedule by resource for the simulated portfolios.

**Figure 62: Portfolio Additions Evaluated**

<table>
<thead>
<tr>
<th>Cumulative Generation Capacity (MW)</th>
<th>Portfolio 1</th>
<th>Portfolio 2</th>
<th>Portfolio 3</th>
<th>Portfolio 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Status Quo</td>
<td>Reciprocating Engine</td>
<td>Solar</td>
<td>Harvest Wind Outage</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>0</td>
<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2018</td>
<td>0</td>
<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2019</td>
<td>0</td>
<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2020</td>
<td>0</td>
<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2021</td>
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<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2022</td>
<td>0</td>
<td>25</td>
<td>0</td>
<td>-30</td>
</tr>
<tr>
<td>2023</td>
<td>0</td>
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<td>-30</td>
</tr>
<tr>
<td>2024</td>
<td>0</td>
<td>50</td>
<td>0</td>
<td>-30</td>
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<tr>
<td>2025</td>
<td>0</td>
<td>50</td>
<td>0</td>
<td>-30</td>
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<tr>
<td>2026</td>
<td>0</td>
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<td>50</td>
<td>-30</td>
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<td>2036</td>
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<td>-30</td>
</tr>
</tbody>
</table>

The portfolios were input into the long term financial model and then subjected to 80 different Slice and price scenarios. Due to the large number of inputs in the financial model and all of the uncertainties surrounding each input, it was concluded that Monte Carlo simulation would produce the most
comprehensive results. The goal was not to simulate each mathematically possible scenario, but to simulate enough scenarios to put bookends around worst case, best case, identify the most likely scenarios, and quantify the cost and risks associated with each portfolio. Cost per megawatt-hour of power supply was chosen as the cost metric and standard deviation of simulation was the risk metric.

**Figure 63: Risk Efficiency Analysis**

![Risk Efficiency Analysis](image)

Figure 63 is a plot of each portfolio’s average cost per megawatt-hour of load served on the x-axis versus the standard deviation on the y-axis. Portfolio evaluation involves assessing cost versus risk. The ideal portfolios can be isolated by fitting a hyperbolic curve, known as the efficient frontier, through the points. Portfolios situated below the vertex, but still on the efficient frontier have the least risk for a particular cost bucket. The ideal portfolio would have a low cost and low risk, but there is generally a tradeoff between the two criteria. It is up to an individual utility to decide whether a higher expected net power cost with lower risk (Reciprocating Engine) or lower expected net power cost with higher risk (Status Quo) is a better fit. The Solar portfolio, on the other hand, is a high cost, high risk portfolio that can immediately be rejected as an option.

A qualitative analysis of the results yields findings that are both expected and interesting. The performance of the various portfolios are consistent with expectations. The LCOE of a reciprocating engine and solar are both higher than forecasted market prices, thus it is unsurprising that portfolios containing resources resulted in higher costs. One of the surprises was the relatively tight range of costs of the various portfolios. The difference between the status quo and adding a sparsely used asset is an average of $1 per megawatt-hour of load served. Part of this can be explained by the prominence of hydroelectric power in the District’s generation resource mix. Costs will fluctuate inversely to hydroelectric power production.
conditions, but should revert to average over the long term. This result also suggests that the District’s inflation adjusted long term power supply costs are relatively stable.
**Preferred Portfolio**

Continuing the status quo and relying on market purchases for any short term capacity deficits is the best performing portfolio in the risk analysis. The benefit of this approach is that the District can target the parts of the year that present the most challenges (winter) while avoiding carrying costs of physical assets during “lower risk” parts of the year (spring and fall). Since there are no energy deficits forecasted through the duration of the study period, there is no reason to procure additional generation assets.

The preferred portfolio requires the District to rely on the REC market to meet RPS obligations in 2026. Market prices for RECs since Washington’s RPS went into effect in 2012 have remained in the low single-digit range. The region is still flush with supply and the District expects the market prices of RECs to remain lower than the cost of acquiring additional REC generating resources.

The District should regularly reevaluate this strategy. If there is a fundamental change to the volatility of the power or REC market, the preferred portfolio could change.
Chapter 10: Action Plan

The District’s IRP defines the District’s need for new resources and investigates different generic resource types with an objective of presenting both quantitative and qualitative analysis of the benefits of pursuing different resource technologies to fulfill the District’s resource load and RPS requirements. The District’s action plan addresses both resource acquisitions and power supply related issues that will require additional investigation outside of the IRP process.

- Based on the information available today, the preferred long term portfolio would meet capacity deficits through market purchases. As a result, the District will continue to monitor market conditions and the viability of meeting the additional requirements through market purchases through monthly Risk Management meetings.

- The 2016 plan shows that the District will have capacity planning deficits in the winter, beginning 2018 that grow over time. Capacity constrained periods during both the winter and summer were observed in the past 2 years, and while prices did reach the triple digits, none of the events resulted in a sustained (over 3 days) high price environment. Buying very high cost power for a few days a year is more economically viable than the cost to acquire and maintain a sparsely used generation asset.

- The IRP team forecasts REC deficits beginning 2026. Given recent regulatory changes in RPS obligations in California and Oregon to 50 percent, it is reasonable to believe that Washington may also increase its RPS. The District will evaluate alternative compliance mechanisms before additional REC generating resources decisions are made.

- The District will continue to monitor the regulatory environment and modify its resource strategy if necessary.

- The District will continue to monitor energy economic fundamentals to ensure that its resource strategy provides rate payers with low cost energy with a low level of risk. Major changes to price and volatility of wholesale electricity, natural gas, and REC s may require changes to the District’s plan.

- Implement all cost-effective conservation consistent with the requirements and any future amendments of I-937

- This IRP examined renewable and energy needs based on District forecasts. While the forecasts were constructed using the best available information, the District will continue to monitor load growth, which can change and with it the energy and renewable requirements.