Integrated Resource Plan
Final
August 24, 2016

Prepared by:

EES Consulting

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

A registered professional engineering corporation with offices in Kirkland, WA and Portland, OR

Telephone: (425) 889-2700 Facsimile: (425) 889-2725
August 24, 2016

Ms. Melinda James-Saffron  
Grays Harbor PUD  
P.O. Box 480  
Aberdeen, Washington 98520

Dear Ms. James-Saffron:

It is with pleasure that EES Consulting, Inc. submit this draft Integrated Resource Plan for Grays Harbor Public Utility District (PUD).

We appreciate all of the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Steve Andersen  
Manager
Contents

CONTENTS ...................................................................................................................................................................... I

EXECUTIVE SUMMARY ................................................................................................................................................... 1

PROJECTED LOADS AND EXISTING RESOURCES ........................................................................................................ 1
PORTFOLIOS .................................................................................................................................................................... 5
RECOMMENDATIONS ....................................................................................................................................................... 7

PROJECTED LOAD/RESOURCE BALANCE ...................................................................................................................... 9

PROJECTED GHPUD LOADS ........................................................................................................................................... 9
EXISTING RESOURCES .................................................................................................................................................. 13
LOAD/RESOURCE BALANCES ...................................................................................................................................... 18

SUPPLY-SIDE RESOURCES ............................................................................................................................................. 24

SUPPLY-SIDE RESOURCE DEVELOPMENT OVERVIEW ............................................................................................... 25
SUPPLY-SIDE RESOURCE COSTS AND CHARACTERISTICS .......................................................................................... 30
NATURAL GAS-FIRED COMBUSTION TURBINES ........................................................................................................... 33
COAL .................................................................................................................................................................................. 34
NUCLEAR ........................................................................................................................................................................... 35
RENEWABLE ENERGY OVERVIEW ............................................................................................................................... 36
WIND .................................................................................................................................................................................. 38
UTILITY-SCALE SOLAR .................................................................................................................................................... 39
BATTERY STORAGE SYSTEMS ....................................................................................................................................... 41
GEOTHERMAL .................................................................................................................................................................. 44
WAVE POWER .................................................................................................................................................................. 45
TIDAL .................................................................................................................................................................................. 46
Pumped Storage ............................................................................................................................................................... 47
20-YEAR (2017-36) LEVELIZED COSTS .......................................................................................................................... 48

LOCAL RESOURCES .......................................................................................................................................................... 50

DISTRIBUTED GENERATION OVERVIEW ........................................................................................................................ 50
ROOFTOP SOLAR .............................................................................................................................................................. 53
COMMUNITY SOLAR .......................................................................................................................................................... 56
UTILITY-SCALE BATTERY SYSTEMS .................................................................................................................................. 57
DEMAND RESPONSE UNITS ........................................................................................................................................... 58
BIOMASS ENERGY OVERVIEW ....................................................................................................................................... 59
LANDFILL GAS PROJECTS ................................................................................................................................................ 60
ANAEROBIC DIGESTERS (FARM MANURE) ........................................................................................................................ 60
WASTEWATER TREATMENT PLANTS .............................................................................................................................. 61
BIOMASS-WOODY DEBRIS ............................................................................................................................................... 61
MICRO-HYDRO .................................................................................................................................................................. 62

RESOURCE STRATEGY ....................................................................................................................................................... 63

BPA POWER ......................................................................................................................................................................... 65
NON-FEDERAL RESOURCES ........................................................................................................................................... 69
DISPLACING BPA TIER 1 POWER .................................................................................................................................... 71
ALTERNATIVES TO MARKET PURCHASES .......................................................................................................................... 72
RENEWABLE ENERGY COMPLIANCE PORTFOLIOS .................................................................................................... 73
PORTFOLIOS FOR COMPLYING WITH RENEWABLE ENERGY REQUIREMENTS ........................................................... 74
COST COMPARISONS ....................................................................................................................................................... 79
RECOMMENDATIONS .......................................................................................................................... 82

BPA TIER 1 POWER .......................................................................................................................... 82
ENERGY EFFICIENCY ....................................................................................................................... 83
EIA RENEWABLE ENERGY PURCHASE REQUIREMENTS .......................................................... 83
LOCAL RESOURCES ....................................................................................................................... 83
DEMAND RESPONSE UNITS .......................................................................................................... 83
ROOFTOP SOLAR ........................................................................................................................... 84
PRE-PAY PROGRAM ....................................................................................................................... 84
TIME-OF-USE RATES ..................................................................................................................... 84
Executive Summary

In 2006, Washington State enacted House Bill 1010 requiring public utilities that are not full requirements customers of the Bonneville Power Administration (BPA) and that serve more than 25,000 customers to complete an Integrated Resource Plan (IRP) in accordance with RCW 19.280. This IRP has been completed in response to that mandate. Under the law Grays Harbor Public Utility District (GHPUD) is required to submit a full report every four years with accompanying updates every two years. GHPUD completed and submitted IRPs in 2012 and 2014.

IRPs evaluate potential future resources in areas of reliability, cost, risk and environmental impact. IRPs consider demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs. This report lays out the analysis performed by GHPUD of its forecast loads, current resources, and options for future resource strategies. In addition, this report details the regulatory considerations and constraints that impact resource planning for the utility.

Projected Loads and Existing Resources

Exhibit ES-1 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2017-36.
As shown above loads are projected to be flat in CY17 through CY36 with no load growth. The load forecast shown above includes anticipated conservation achievements. According the Conservation Potential Assessment (CPA) completed by EES Consulting in October 2015, projected cumulative conservation acquisitions are approximately 66,265 MWh or 7.6 aMW over the study period. Exhibit ES-2 below shows the base case annual cost effective energy efficiency potential identified in the CPA by sector.

Exhibit ES-2
Base Case Annual Cost Effective Energy Efficiency Potential (aMW)

GHPUD currently purchases nearly all of the power required to serve its retail load from BPA under a 20-year Slice/Block contract that expires in September 2028. The basic premise of the Slice product is that BPA customers pay a fixed percent of BPA’s power costs in exchange for a fixed percent of FBS generation and capabilities. The firm component of the Slice product is based on critical water firm load carrying capability. Because the timing of utility loads and the firm output of FBS resources do not match within the year, the entire firm component may not be available in a shape that can meet a utility’s retail loads. At other times, such as during the spring snow melt off, part of the firm component may be surplus to the customer’s load requirements. The non-firm component is surplus power above critical water firm load carrying capability. Slice/Block customers must acquire additional resources during hours in which resources are less than load requirements and sell surplus energy in the market during hours when resources exceed load requirements.

Exhibit ES-3 shows that, under average water conditions, GHPUD has surplus energy in all months. Since no load growth is projected for GHPUD, the monthly load/resource balance shown below in 2018 will only change between 2018 and 2036 to the extent that BPA’s resource
capabilities changes through 2028 and to the extent that BPA makes changes the amount of power it makes available under new power contracts that will begin in October 2028.

**Exhibit ES-3**
Projected 2018 Load and BPA Purchases (MWh)

Note: BPA Block purchases are set for the current rate period (through September 2017). Block quantities shown above assume BPA Block plus BPA Slice will be equal to projected load on an annual energy basis.

As a Slice/Block customer, GHPUD primarily serves its peak demands using a combination Slice/Block purchases and wholesale market purchases.

GHPUD’s existing resource portfolio also includes the Nine Canyon Wind Project, the Coastal Community Action Program Wind Project, the Sierra Pacific Industries Biomass Generation Project, the Frederickson Project, a natural gas-fired combustion turbine, as well as market transactions to follow load. Exhibit ES-4 below shows GHPUD’s load/resource balance including non-federal resources.
Note: BPA Block purchases are set for the current rate period (through September 2017). Block quantities shown in subsequent rate periods assume BPA Block plus BPA Slice will be equal to projected load.

As shown above in Exhibit ES-4, GHPUD is long on resources through 2023 when its non-federal resource contracts expire. On a shorter term basis, GHPUD may experience deficits during some periods. For example, GHPUD can expect hourly deficits during high load winter events, such as cold snaps. This is particularly true after the expiration of the Frederickson contract.

Exhibit ES-5 below shows the nominal levelized costs of the supply-side resources discussed in the body of this report. The 20-year levelized cost of energy efficiency is per GHPUD’s 2015 CPA.
Exhibit ES-5 shows that the wholesale market and energy efficiency are the lowest cost resources followed by BPA Tier 1 rates.

Portfolios

Since GHPUD is in load/resource balance on an annual basis (as shown in Exhibit ES-4 above), GHPUD would have surplus energy sales if additional resources were added to its resource portfolio. GHPUD is, however, short on renewables as shown below in Exhibit ES-6.
The “RPS Target” shown above is equal to 9 percent of GHPUD’s projected retail load in 2017-19 and 15 percent of projected retail load in 2020-2036. As shown above, GHPUD needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2022. Three following portfolios were developed for meeting GHPUD’s renewable energy purchase requirements:

- **Portfolio #1**: Purchase the output of wind and utility scale solar projects to meet renewable energy short positions.
- **Portfolio #2**: Purchase the output of wind and utility scale solar projects to meet to 50 percent of GHPUD’s renewable energy short positions and Renewable Energy Credits (RECs) to meet the other 50 percent.
- **Portfolio #3**: Meet all renewable energy short positions with REC purchases.

The cost of meeting renewable energy requirements was calculated for the three portfolios for the period 2022-2036. The 5-year period 2017-21 was excluded from the analysis because GHPUD has already committed to resources sufficient to meet the EIA’s renewable energy purchase requirements in 2017-21 (as shown in Exhibit ES-6). A sensitivity analysis was included to determine a range of costs associated with each portfolio.

For each portfolio, ES-7 shows the range of potential costs associated with acquiring new renewable resources and/or REC purchases required to meet the EIA’s renewable energy...
requirements. Since GHPUD either has surplus energy or is in load/resource balance without additional resources, the new resources acquired in portfolios #1 and #2 are not needed to serve load and are assumed to be re-sold at market prices. The net costs shown below include the revenue associated with re-selling the new renewable energy purchases in portfolios #1 and #2.

**Exhibit ES-7**

2024-36 Net New Renewable Resource and REC Costs (thousands)

Net costs under base case pricing assumptions are depicted by the red diamonds in Exhibit ES-7. The bottom of the blue box shows costs under the low sensitivity pricing assumptions while the top of the blue box shows costs under the high sensitivity pricing assumptions. As shown above portfolio #3, the “only purchase RECs” portfolio, is, by far, the lowest cost portfolio.

**Recommendations**

Below are specific recommendations based on observations made throughout this report.

**BPA Tier 1 Power:** GHPUD should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently lower than Tier 1 rates, market prices are exposed to price risks to which non-carbon emitting resources, such as BPA Tier 1 power, are not exposed.

**Energy Efficiency:** The cost effective energy efficiency measures identified in GHPUD’s 2015 CPA, are the least expensive resources available to GHPUD. Implementing these measures will assure that GHPUD’s loads will remain flat (no load growth) which will, as a Slice/Block customer, reduce GHPUD’s market price risk exposure.
Renewable Energy Purchase Requirements: Due to the expiration of existing contracts GHPUD is short renewable energy beginning in 2024. The least cost and lowest risk strategy to complying with renewable energy purchase requirements is to purchase RECs in amounts sufficient to eliminate projected renewable energy short positions.

Local Resources: In order to diversify its resource portfolio, increase its self-sustainability and decrease its dependence on BPA transmission to serve load and reduce its wholesale transmission costs, GHPUD should promote local resource development and pursue state and federal grant money that would allow GHPUD to accelerate local resource development. Potential local resources include small scale solar, cogeneration at wastewater treatment plants, and battery storage systems that complement small scale solar systems and provide backup in the event of a transmission contingency.

Demand Response: GHPUD should gauge its customers’ interest in participating in DRU programs. If enough customers are interested, GHPUD should pursue the installation of DRUs to help GHPUD reduce its peak demands, power supply costs and exposure to market price and availability risk.

Rooftop Solar: GHPUD currently has few (near 20) customers with rooftop solar installations. However, the cost of solar power is expected to decrease significantly over the next 10 years which, despite the relatively low capacity factor of rooftop solar in GHPUD’s service territory, will make rooftop solar more attractive to GHPUD’s customers. GHPUD should consider taking steps to prepare itself for growth in rooftop solar installations so that GHPUD can be in a better position to operate a truly “smart” and efficient grid. This would ultimately result in lower distribution system and power supply costs.

Pre-Pay Program: GHPUD should consider providing residential customers with a pre-pay option. Pre-pay programs increase customers’ awareness of how much energy they consume and allow customers to control their usage and costs. Pre-pay programs implemented at other electric utilities have been proven to result in energy savings.

Time-of-Use Retail Rates: GHPUD should consider providing customers with optional time-of-use retail rates. TOU rates should encourage customers to shift loads to periods in which wholesale market prices are lowest (toward off-peak hours and away from peak demand hours) which could reduce the utility’s exposure to wholesale market price risk.
Projected Load/Resource Balance

The objective of this study is to evaluate Grays Harbor PUD’s (GHPUD) existing resources to determine future net energy and capacity requirements. In addition, this analysis evaluates the risks and opportunities associated with GHPUD’s existing resources and a variety of alternative resources that could be deployed to serve the PUD’s projected above-High Water Mark (HWM) loads over the 20-year planning period 2016 to 2035.

EES Consulting has reviewed GHPUD’s projected loads and, based on GHPUD’s projected load/resource balance, assessed GHPUD’s potential future resource needs over a 20-year study period (2017-36). Projected loads provided by GHPUD, as described below, will be used to assess GHPUD’s above-HWM loads and future resource needs.

Projected GHPUD Loads

Energy Load Projections

Exhibit 1 below shows GHPUD’s historic loads (energy and peak demand) for the calendar years 2013 through 2015. Average load over the three-year period was near 100 average annual megawatts (aMW). Monthly peak demands varied from lows near 100 MW in the summer to the highs in the 200 to 220 MW range in the winter.
GHPUD provided an electric load forecast for 2017 through 2021. The load forecast is consistent with the load forecast currently being used by The Energy Authority (TEA) to project GHPUD’s power supply costs through 2021. The model used by TEA is known as the TEA Financial Model. In order to extend the load forecast out through 2036, a load growth rate had to be assumed. Based on input from GHPUD staff no load growth was assumed between 2021 and 2036. Some of the key assumptions for the base case forecast are provided below.

- No significant large customer additions
- Continue conservation acquisitions
- No load growth
- No changes in load composition

Projected total power requirements in megawatt-hours (MWhs) are based on the sum of forecast retail sales and distribution system losses.

Monthly projected peak demands were calculated by applying monthly load factors to monthly projections of energy consumption. The Bonneville Power Administration (BPA) forecasts GHPUD loads on an on-going basis. BPA’s forecast of GHPUD’s loads includes both monthly energy and monthly peak demand. The total energy load forecast included in the BPA’s forecast of GHPUD loads is materially greater than the load forecast included in TEA’s Financial Model. The load forecast in the Financial Model more accurately tracks with GHPUD’s load over the past three historic years and with GHPUD staff’s expectations for future load levels.

The load factor included in the BPA load forecast was applied to the energy forecast in the TEA Financial Model to calculate projected monthly peak demands. The projected system peak demand and energy load forecasts result in annual load factors of 55 percent, with monthly load factors ranging from 63 to 86 percent.

Exhibit 2 shows base case projected total system monthly energy (power purchase requirements) and peak demands for the first three years of the study period (2017-19).
Exhibit 2
2017-19 Projected Monthly Loads - Peak Demand and Energy

Exhibit 3 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2017-36.

Exhibit 3
Projected Annual Loads – Peak Demand and Energy

As shown above loads are projected to be flat in CY17 through CY36 with no load growth.
Trends

One notable trend, with respect to GHPUD’s projected loads, is the projected decrease in average energy use per residential customer. Residential load is currently 50 percent of total load. While projected residential load is flat for all customer classes, the number of residential customers is projected to increase by 0.5 percent per year. The result of flat residential loads and increasing residential customer counts is decreasing average usage per residential customer. Average usage is forecast to decrease by 9 percent over the 20-year study period.

Exhibit 4 below shows the projected decrease in average residential usage that is embedded in the load forecasts shown above in Exhibits 2 and 3.

The projected decrease in average usage is not unexpected. New homes consume less energy than older homes. New appliance and electronics are also more energy efficient. The decrease in average usage is primarily a result of increases in energy efficiency and is being seen by utilities throughout the electric industry. Utilities with high numbers of customers participating in net metering, primarily by installing rooftop solar, are seeing greater decreases in residential average usage. Net metering is discussed in greater detail in the “Local Resource Options” section of this report. The electrification of transportation is a factor that could stall or reverse the trend of decreasing average energy usage. However, a large increase of electric vehicles in GHPUD’s service territory is not anticipated in the near future. This issue will be re-evaluated when GHPUD conducts its next IRP update in calendar year 2018.
**Existing Resources**

GHPUD’s resource portfolio includes the BPA Slice/Block contract, the Nine Canyon Wind Project, the Coastal Community Action Program Wind Project, the Sierra Pacific Industries Biomass Generation Project, the Frederickson Project, a natural gas-fired combustion turbine, as well as market transactions to follow load. Each of these resources is discussed below.

**BPA Slice/Block Contract**

GHPUD currently purchases nearly all of the power required to serve its retail load from BPA under a 20-year contract that expires in September 2028. BPA markets electric energy from 29 federal hydroelectric projects in the Pacific Northwest, the Columbia Generating Station (CGS), and contractual purchases and exchanges to meet approximately 50 percent of the Pacific Northwest’s energy requirement.

CGS is a nuclear project with a generating capacity of 1,150 MW that is owned and operated by Energy Northwest (ENW). ENW is a joint operating agency consisting of 28 Washington state public utilities.

BPA’s contractual purchases include shares of the output from four wind projects from which BPA has the rights to approximately 250 MW of capacity. The Renewable Energy Credits (RECs) associated with the wind projects are included in BPA’s Tier 1 rates. The RECs are transferred to BPA’s customer utilities annually.

BPA also owns and operates approximately 75 percent of the Pacific Northwest’s high-voltage transmission system. BPA’s transmission facilities interconnect with utilities in the Canadian province of British Columbia and with utilities in California.

As a Slice/Block customer GHPUD purchases an approximately 1 percent share of the real-time capability of the FBS resources in addition to monthly flat blocks of energy.

BPA’s rate structure changed dramatically in October 2011. The rate structure was developed through a formal proceeding known as the Tiered Rate Methodology (TRM). Beginning in October 2011, BPA’s rates were tiered with market-based rates serving load growth above 2010 actual loads (the high water mark or HWM). Under TRM, total Tier 1 allocations roughly equal the capability of the Federal Based System (FBS) under critical water conditions. With this approach, each BPA customer effectively receives a share of output from the FBS for a 20-year contract period. Power requirements above Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers.

Tier 1 power costs are based on current FBS costs; however, the quantity of power GHPUD is able to purchase at these rates is limited. BPA used weather and conservation adjusted loads from October 2009 through September 2010 (BPA fiscal year 2010) to set GHPUD’s HWM, or the
maximum amount of energy GHPUD can purchase at cost-based Tier 1 rates. Tier 1 rates are determined in formal rate proceedings every other year.

GHPUD’s Slice/Block purchases are at Tier 1 rates, which include a composite customer charge, a Slice customer charge, a non-Slice customer charge and monthly and daily diurnal load shaping charges.

The basic premise of the Slice product is that BPA customers pay a fixed percent of BPA’s power costs in exchange for a fixed percent of FBS generation and capabilities. Slice has firm and non-firm components. The firm component is based on critical water firm load carrying capability. Because the timing of utility loads and the firm output of FBS resources do not match within the year, the entire firm component may not be available in a shape that can meet a utility’s retail loads. At other times, part of the firm component may be surplus to the customer’s load requirements. The surplus firm component is likely to occur in spring months, when water conditions are high. The non-firm component is surplus power above critical water firm load carrying capability. Slice purchasers must acquire additional resources during hours when their share of FBS resources are less than their load requirements and are free to sell surplus power in the market during hours when their share of FBS resources exceeds their load requirements.

Slice percentages were determined assuming FBS capability under critical water. If actual water conditions and associated FBS capability exceed critical water in a given year, Slice purchasers may sell surplus energy on the market or displace other more-costly resources. The amount of surplus energy in a given hour, day, month and year is dependent upon water conditions and the extent to which the resulting FBS capability exceeds utility load requirements.

Exhibit 5 below shows calendar year 2018 projected loads and BPA block, Slice and surplus Slice. “BPA Slice” in Exhibit 5 represents GHPUD’s share of monthly Slice generation under critical water conditions. As shown below, during winter months (December through March) and April, GHPUD’s projected monthly loads exceed its block and Slice purchases under critical water. As such, GHPUD will rely on surplus Slice and/or market purchases to serve part of its projected load.

Exhibit 5 also shows that GHPUD will have surplus energy in all other months (May through November) even under critical water conditions. All months show surplus generation under average water conditions. Since no load growth is projected for GHPUD, the monthly load/resource balance shown below in 2018 will only change between 2018 and 2036 to the extent that BPA’s resource capabilities changes through 2028 and to the extent that BPA makes changes the amount of power it makes available under new power contracts that will begin in October 2028.
Exhibit 5
Projected 2018 Load and BPA Purchases (MWh)

Note: BPA Block purchases are set for the current rate period (through September 2017). Block quantities shown above assume BPA Block plus BPA Slice will be equal to projected load on an annual energy basis.

The utilities that purchase power from BPA under Slice/Block contracts insure themselves against low water years by holding funds in reserve accounts that are earmarked for increases in power supply costs. Relatively larger BPA customer utilities, like GHPUD, are able to absorb the risks associated with purchasing power under a Slice/Block contract.

As a Slice/Block customer, GHPUD primarily serves its peak demands using a combination Slice/Block purchases and wholesale market purchases.

**Frederickson Project**

The Frederickson Project is located southeast of Tacoma in Pierce County. The project has 249 MW of capacity, however, supplemental duct-firing generation can boost maximum output to 275 MW. The project, which came on-line in 2002, employs combined-cycle combustion-turbine technology that allows it to generate electricity using both a natural gas cycle and, from the exhaust heat of its power-generating turbines, a steam cycle. The two-stage process boosts operating efficiency, lowers fuel costs, and cuts air emissions. Combined-cycle plants like the Frederickson Project operate more efficiently than single-cycle gas-fired plants.

GHPUD purchases a 45 MW share of project output via a 20-year purchase agreement that expires on August 31, 2022. The heat rate of the project is 7,100 Btu/kWh. Project costs include
a capacity charge, fixed and variable operation and maintenance costs, natural gas fuel costs and gas pipeline transportation costs. The project is dispatchable and only runs when economic to do so. GHPUD can, on a daily basis, choose to use Frederickson to serve load if it is short on power and the running costs of the project are less than alternative resource costs, most likely wholesale market power costs. The project can be dispatched to the market on a diurnal basis if it is economic to do so. GHPUD receives revenues from market power sales when the project is dispatched to the market.

**Nine Canyon Wind Project**

The Nine Canyon Wind Project is located in south-central Washington just south of Kennewick. Constructed in three phases between 2002 and 2007, the project includes 63 wind turbines with a maximum generating capacity of 95.9 MW. Phases I and II include a total of 49 turbines each capable of producing 1.3 MW. The third phase added 14 larger turbines, each capable of producing 2.3 MW, for a total of 63 turbines between the three phases.

The project is owned and operated by ENW. GHPUD purchases 12.5 percent of the output from phases I and II of the project, which is equivalent to approximately 8 MW of capacity and 2.5 aMW. GHPUD also purchases 12 MW of capacity from Phase III, for a total capacity of 20 MW and approximately 5 aMW of energy. GHPUD’s shares of Phases I, II and II expire in July 2021, July 2023 and July 2030, respectively.

**Coastal Community Action Program Wind Project**

The 6 MW Coastal Community Action Program Wind Project located in Grayland, Washington, was developed by the Coastal Community Action Program (“CCAP”). The project’s four turbines generate approximately 1.8 aMW of energy, all of which is sold to GHPUD. The revenue from the project supports CCAP’s programs that benefit low-income families in Grays Harbor and Pacific counties. GHPUD’s contract with CCAP expires in June 2030.

**Sierra Pacific Industries Biomass Generation Project**

GHPUD entered into a power purchase agreement with Sierra Pacific Industries to purchase biomass energy. The energy generated from the project qualifies as eligible renewable energy under the state of Washington’s Energy Independence Act. Under the current contract, GHPUD purchases 11 aMW of energy during all hours. GHPUD’s contract with Sierra Pacific expires in July 2022.

**Distributed Generation**

Distributed generation can provide advantages over central-station generation, including: enhanced localized reliability; improved efficiency due to avoided transmission losses; and a partial hedge against changing future power costs. However, the technologies are relatively new
to the electric industry and rapid deployment of distributed generation can cause concerns regarding distribution system reliability. For example, the rapid growth of rooftop solar in Maui increased the total solar generation on some circuits to a level where the utility temporarily halted the installation of additional rooftop solar installations until reliability issues could be addressed.

In net metering the meter simply “runs backwards” when a homeowner’s solar panel or other generation equipment is producing more electricity than the property is using, sending the excess energy back through the utility’s distribution system lines to other energy consumers. An example of a typical net metering customer’s monthly load, generation and net metered load is shown below in Exhibit 6.

Net-metering rules vary by state. Some states limit the amount of surplus energy that can be rolled over from year to year, while others do not. Washington’s net-metering law applies to systems up to 100 kilowatts of capacity that generate electricity using solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). All customer classes are eligible, and all utilities - including municipal utilities and electric cooperatives - must offer net metering.

Under Washington state law, net metering is available on a first-come, first-served basis until the cumulative generating capacity of net-metered systems equals 0.5 percent of a utility’s 1996 peak demand. Based on GHPUD’s net metering policy, the cap on net metering for GHPUD is 255 kW or 0.255 MW. Half of the utility’s available aggregate net metering capacity is reserved for systems generating electricity using non-fuel cell technology.

GHPUD offers net metering to customers who generate their own electricity with fuel cells, solar, wind, or hydro-powered systems of with capacity of 100 kilowatt or less. Net excess generation
(“NEG”) is credited to the customer’s next bill at the utility’s retail rate. At the end of each calendar year, any remaining NEG is reimbursed to the customer by the district at 50 percent of the current retail energy rate.

Net-metered systems must include all equipment necessary to meet applicable safety, power quality and interconnection requirements established by the National Electric Code, the National Electric Safety Code, the Institute of Electrical and Electronic Engineers and Underwriters Laboratories.

The total installed capacity of net metered customers in GHPUD’s service territory is currently 129 kW. Net metered customers have primarily installed rooftop solar panels. Of the 129 kW of capacity installed by net metered customers, 117 kW is rooftop solar. The average installed generating capacity per net metered customer is 4.2 kW.

There has been an increase in rooftop solar installations with 14 new installations over the past 36 months. The number of net metered customers has increased by 20 over the past 36 months. In total, there are currently 32 net metered installations in GHPUD’s service territory.

**Load/Resource Balances**

As shown above in Exhibit 3, the load forecast provided by GHPUD projects no load growth over the 20-year study period. The load forecast includes anticipated conservation achievements. According the Conservation Potential Assessment (CPA) completed by EES in October 2015, projected cumulative conservation acquisitions are approximately 66,265 MWh or 7.6 aMW over the study period. The CPA base case shows annual conservation acquisitions of near 3,000 MWh or 0.4 aMW across all sectors including residential, commercial, industrial, distribution efficiency and agriculture. Exhibit 7 below shows the base case annual cost effective energy efficiency potential identified in the CPA by sector.
Under the current BPA power contract, GHPUD’s contract HWM (CHWM) is 133.2 aMW. GHPUD’s CHWM was established based on GHPUD’s historic loads and represent GHPUD’s maximum allocation of BPA Tier 1 system power. GHPUD’s rate period HWM (RHWM) for the current rate period (October 2015 through September 2017) is 129.9 aMW. RHWMs are established for each two-year rate period based on projected GHPUD loads and projected BPA Tier 1 system capability. GHPUD’s FY loads are projected to be near 113 MW, or 20 aMW less than its RHWM during the current rate period. Under the current BPA contract, load growth above a utility’s RHWM is served at market-based prices by either one of BPA’s Tier 2 products or by a non-federal (i.e. non-BPA) resource. GHPUD, and all other BPA customer utilities, had to inform BPA of their Tier 2 purchase elections for FY15-FY19 by September 30, 2011. The Tier 2 purchase elections were based on above-HWM load projections at the time of the deadline (September 2011). GHPUD committed to supplying any above-HWM load with the non-federal purchases detailed above.

Exhibit 8, below shows the load forecast provided by GHPUD compared to GHPUD’s contract HWM and its current rate period HWM. The RHWM reflects GHPUD’s projected loads for the current rate period (October 2015 through September 2017) as well as the projected output of BPA’s resources. RHWMs in future rate periods cannot exceed GHPUD’s CHWM. RHWMs vary from rate period to rate period based on the projected loads of all of BPA’s customer utilities and the projected output from BPA’s Tier 1 system resources. Exhibit 8 also shows projected GHPUD loads with and without projected conservation achievements.
Exhibit 8 shows that absent GHPUD’s projected conservation achievements, which are per the CPA base case, GHPUD’s loads would increase. Without conservation GHPUD’s projected loads would increase by 7 aMW between 2017 and 2036, at an average annual escalation rate of 0.3 percent.

As shown above GHPUD’s load is projected to be less than its rate period and contract HWMs through the end of the contract period (September 2028) and beyond. Exhibit 8 only shows GHPUD’s BPA power contract. When GHPUD’s non-federal resources are included in the load/resource balance equation, it is clear that GHPUD is long on resources through 2023 when the non-federal resource contracts expire. Exhibit 9 below shows GHPUD’s load/resource balance including non-federal resources.
Note: BPA Block purchases are set for the current rate period (through September 2017). Block quantities shown in subsequent rate periods assume BPA Block plus BPA Slice will be equal to projected load.

The “BPA Slice” quantities are based on GHPUD’s share of FBS generation under critical water conditions. The “Surplus Slice” quantities shown above are based on additional generation available to GHPUD under average water conditions.

The projected Frederickson generation shown above is per TEA’s Financial Model which assumes the projects runs during 80 percent of on-peak hours and 17 percent of off-peak hours each year. The project is dispatched only in periods when it is economic to do so (i.e. when project running costs are less than wholesale market prices). The project is assumed to be displaced during off-peak hours in most months because project running costs are greater than projected off-peak market prices during off-peak periods in most months. The project is also projected to be displaced during at least one spring month each year. Hydro generation typically peaks in the spring when the snow pack melts. High hydro generation and low loads often make dis-patchable units such as Frederickson uneconomic during spring months.

As shown above in Exhibit 9, GHPUD has large surpluses through 2022, prior to the expiration of the Frederickson contract at the end August 2022. The surpluses decrease beginning in 2023. However, under average water conditions GHPUD is still surplus energy on an annual basis.
On a shorter term basis, GHPUD may experience deficits during some periods after the expiration of the Frederickson contract. For example, GHPUD can expect hourly deficits during high load winter events, such as cold snaps. GHPUD’s projected peak winter load is projected to be 205 MW under normal weather. Peak loads have, historically, been known increase 25 percent above expected during cold snaps. A 25 percent increase in load would result in a peak demand of near 260 MW. After the expiration of the Frederickson contract a peak demand of 260 MW would very likely exceed the capability of GHPUD’s resources.

It is unknown whether the quantity of power and transmission currently provided by BPA under existing contracts will be available under new contracts that begin in October 2028. There is also uncertainty with respect to BPA’s future power rates. BPA’s rates continue to increase with each two-year rate period. Thanks to low natural gas prices and depressed loads BPA’s power rates are currently greater than wholesale market prices. Whether or not this trend will continue is unknown. Based on current projections of wholesale market and natural gas market prices it could be argued that BPA’s rates will be above market for an extended period of time.

Exhibit 10 below shows projected wholesale market prices compared to projected BPA rates. The rates and market prices shown in Exhibit 10 are based on projections provided by BPA in October 2015 as part of its “BPA Focus 2028” process. BPA provided low, base, and high projections of BPA rates. BPA did not provide a base case market price forecast but rather provided a range of market prices that fall between the low and high market price forecasts shown below.
BPA’s projections extend out through the year 2030, which is two years after the current power contracts expire in 2028. The average annual increase in the BPA base Priority Firm (PF) rates shown above is 1.9 percent. Through 2018 BPA’s PF rates are greater than the “high market” forecast. For the period 2021 through 2030, PF rates are in between the high and low market prices forecasts with base case PF rates trending toward the “low market” price forecast. It should be noted that projected market prices shown above are for flat power purchases (as opposed to a load following contract). As such, the comparison of projected BPA load following rates and wholesale flat market prices is not an apples-to-apples comparison.

BPA’s current short-term Tier 2 rate is shown in Exhibit 10 for comparison purposes.

The key takeaway from Exhibit 10, above, is that if wholesale market prices continue to be relatively low, BPA may not be the lowest cost resource option for GHPUD in the future. Given the uncertainty with respect to BPA’s future rates and the amount of power that will be made available to BPA’s customer utilities under the post-2028 contracts, it is prudent that GHPUD consider its future resource options.
Supply-Side Resources

This section provides background information on the current status of a wide range of supply-side resource options. This includes some history as well as the latest information on commercially operational projects and demonstration projects in place, as well as research currently underway. The research surveyed available sources in the Western Electrical Coordinating Council (WECC) to determine potential future options available to GHPUD. This section is followed by the “Local Resource Options” section which provides a qualitative discussion of potential distributed generation resource options in GHPUD’s service territory.

As noted above GHPUD currently purchases power from BPA as a Slice/Block customer under a 17-year contract that expires at the end of September 2028. Under the current BPA power contracts, total Tier 1 allocations are roughly equal to the capability of the FBS under critical water conditions. Power required to serve above-HWM load may be provided by owned resources or purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers.

BPA’s Tier 2 products are priced at Tier 2 rates. BPA’s Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that will be used to serve Tier 2 loads. BPA offers utilities several Tier 2 power products and associated pricing. Tier 2 product choices include:

Short-Term Tier 2: Utilities commit to purchase power for two-year rate period. Rates are determined each rate period and reflect the cost of market purchases to serve short-term Tier 2 purchases.

Vintage Tier 2: Utilities make a long-term commitment to purchase the output from a specific generating resource. Rates are based on the projected costs of the resources.

Load Growth Tier 2: Utilities must commit to purchase all load growth requirements for the entire contract period. Rates are determined every two years and are designed to recover the full costs of the required generating resources, or market purchases. This product is not available to GHPUD.

Exhibit 11 below shows BPA’s Tier 2 product rates over the first three rate periods under TRM (FY12-13, FY14-15 and FY16-17). Wholesale Mid-Columbia actual and projected prices are also shown.
Exhibit 11 shows that during the first four years under TRM (FY12-FY15) actual Mid-Columbia wholesale market prices have been significantly less than BPA’s short-term Tier 2 rates. Mid-Columbia actual prices were 42 percent less than BPA’s short-term Tier 2 rates during the four-year period.

Since BPA’s Tier 2 short-term rates are based on market purchases made at market prices, Tier 2 short-term rates should, on a planning basis, be considered to be equal to forecast market prices.

**Supply-Side Resource Development Overview**

There are several legislative mandates that will play key roles in the development of new resources in the Northwest. While a wide range of supply side resource options are considered by utilities in the screening of resources, many are quickly eliminated from consideration due to the legislative mandates.

Due to RPS requirements in Washington and elsewhere in the region (California, Oregon and Montana), there is currently a high demand for eligible renewable resources. Utilities in Washington State with 25,000 customers or more are obligated to purchase eligible renewable energy on an annual basis in order to comply with the Energy Independence Act (EIA). The EIA requires utilities to obtain increasing percentages of their total retail load from eligible renewable resources, such as solar and wind. The renewable energy purchase requirements increase from 3 percent in 2012-15 to 9 percent in 2016-19 and 15 percent beginning in 2020. GHPUD met its
EIA renewable energy purchase requirements primarily through Renewable Energy Credit purchases during the first four years of compliance (2012-15).

Oregon’s largest utilities currently must acquire 15 percent of their energy from renewables. The requirements increase to 20 percent in 2020, 25 percent in 2025 and 50 percent in 2040.

As shown below in Exhibit 12, during the twelve-year period 2003 through 2014 supply side resource development in the Northwest was primarily limited to wind projects required to meet renewable portfolio standards and natural gas plants. Exhibit 12 demonstrates that wind is the most readily available and cost-effective renewable resource while natural gas-fired generation is the most readily available and cost-effective non-renewable resource. According the NWGCC 8,334 MW of wind and 3,648 MW of natural gas-fired generation was developed between 2003 and 2014 compared to 285 MW of biomass, 175 MW of hydro and 26 MW of utility-scale solar.
Supply-side resources can be divided into two categories—controllable and uncontrollable. Most resources that are uncontrollable are also eligible renewable resources, such as wind and solar power. Some renewable resources are controllable such as landfill gas and biomass. Non-renewable resources typically are controllable or what in the industry is known as dispatchable. Exhibit 13 below shows a summary of supply-side resource characteristics.
Exhibit 13
Supply-Side Resource Characteristics

<table>
<thead>
<tr>
<th>Resource</th>
<th>Dispatchable</th>
<th>Energy</th>
<th>Capacity</th>
<th>Flexibility</th>
<th>New Builds</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Limited</td>
</tr>
<tr>
<td>Coal</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Natural Gas – Base Load</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Natural Gas – Peaker</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Nuclear</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Wind</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Solar - Photovoltaic</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Solar – Thermal</td>
<td>Limited</td>
<td>Yes</td>
<td>Limited</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Storage (e.g. Battery)</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Demand Response*</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

*Including dispatch-able load.

Source: Northwest Power and Conservation Council presentation 4/2/13

It should be noted that the supply-side resources developed in the Northwest over the past decade have primarily been wind projects and as such, have no dispatch-ability or contribution to meeting peak demands. According to the draft 7th Power Plan, while the region’s hydroelectric system is capable of providing adequate generation to meet energy load requirements and peaking capacity requirements under base case conditions, it is likely that the region will need additional winter peaking capacity to maintain system adequacy under low and extreme weather conditions. As such, dispatch-able supply-side resources that can provide capacity will be the most likely candidates for development over the next five to ten years.

Ownership versus Partnering

The costs associated with the various supply side resource alternatives included in this report are the same regardless of whether a utility chooses to purchase shares of the output of a generating resource via a power purchase agreement or to own the resource outright. There are advantages to both options. The advantages to purchasing a share of the output from a generating resource rather than developing and owning a resource include:

- Economies of scale typically show that resources need to be fairly large (minimum of 70 to 100 MW) to be cost effective.
- Resource development contains significant risk, such as capital expenditure overruns and delays in the commercial operation date.
- Resource operation also includes significant risk, such as the potential for major unplanned outages and fuel price uncertainties.
The most significant risks associated with resource development include capital expenditure overruns and delays in the commercial operation date ("COD"). Capital expenditure overruns can be caused by increased costs associated with plant equipment, fuel transportation infrastructure (i.e. gas pipeline interconnects) and transmission interconnections. Delays in the COD could require the utility to purchase market power to cover the months prior to the COD when the utility may be short resources due to the delay. This represents a significant risk because the utility would have no choice but to pay prevailing market prices. The complexity of arranging capital financing can also be very time consuming, complicated, and could lead to delays in the COD. The complexity and time required to set up financing is only exacerbated when multiple entities/utilities with different structures (municipalities, coops, public utilities, etc.) finance and build a resource together.

There are also significant risks associated with resource ownership after a project has achieved commercial operation. The most significant of these risks are fluctuating fuel prices and major plant outages. Both of these risks could leave a utility relying on fuel or power markets to provide power required to serve load. Historically, natural gas markets in particular have shown great volatility. This volatility requires utilities to closely manage the risks associated with their fuel purchases via risk management policies. Locking in fuel prices is the best way to hedge against a utility’s exposure to fluctuating market prices; however, utilities that own gas-fired resources can never fully insulate themselves from market uncertainty. Major plant outages could leave a utility with no other option but to purchase energy at prevailing electric market prices. This represents significant risk exposure for the utility during these periods.

There are also benefits to resource ownership including:

- Ability to economically dispatch the resource
- Fewer transmission constraints if the resource is sited within the utility’s service territory
- Greater ability to hedge market risks associated with fuel purchases
- Ability to manage fuel transportation costs
- Greater flexibility to use the resource as a load following resource, particularly with respect to meeting peak demands

There are opportunities for GHPUD to participate in the acquisition of above-HWM load serving resources with other utilities. Many of BPA’s customer utilities have formed strategic partnerships that enable shared resource developments and/or acquisitions. The potential benefits of acquiring resources within a pool of utilities includes reduced costs due to economies of scale, diversified pool of alternative resources technologies that may not otherwise be available to an individual utility and access to information regarding potential new resource opportunities that may not otherwise be available.

Strategic partnerships often take the form or “power pools”. Power pools allow for greater efficiencies as member utilities share the administration and capital costs burdens associated with new resources. Going it alone allows for the greatest flexibility regarding resource type and location. However, going it alone does not allow utilities to take advantage of economies of scale.
and scope. In addition, scheduling and purchasing power in increments of at least 25 megawatts can result in savings via economies of scale. Buying and selling power on the open market in relatively small pieces can be administratively burdensome and result in paying premiums for purchases and related services.

Supply-Side Resource Costs and Characteristics

Estimated cost information for both fossil fuel-fired and eligible renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The NWPCC’s 7th Power Plan, annual data provided by the Energy Information Administration and IRPs developed by regional utilities in the Pacific Northwest in 2014-15 were surveyed to provide benchmarks for capital, fixed and variable operation and maintenance, and environmental mitigation costs.

Fossil fuel-fired resource cost estimates include environmental mitigation costs including costs associated with carbon dioxide (“CO₂”), mercury and nitrous oxide. These costs are estimated based on potential regulatory mandates that cause generators to either a) incur penalty charges or b) install equipment to reduce emissions to mandated levels.

There are three proposed carbon policies that require consideration for utilities located in Washington state. These include the Environmental Protection Agency’s (“EPA”) Clean Power Plan, the Washington State Department of Ecology’s Clean Air Rule and Initiative-732, which will be voted on this November and, if passed, would impose a tax on carbon emissions. Each of these is discussed below.

Clean Power Plan

The Executive Branch has, over the past decade, moved forward with regulatory actions to limit Greenhouse Gas (“GHG”) emissions. As a result of the 2007 Supreme Court finding in Massachusetts v. EPA, GHG emissions were determined to be subject to the Clean Air Act and, in a later ruling, determined to contribute to air pollution anticipated to endanger public health and welfare. In 2009, the EPA issued an “endangerment finding,” obligating the agency to regulate emissions of GHG from stationary sources such as power plants. The EPA released draft New Source Performance Standards (“NSPS”) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO₂ emissions from new fossil fuel-fired power plants to 1,000 to 1,100 pounds of CO₂ per megawatt hour, a level achievable by newer natural gas combined-cycle plants. The exact limit of CO₂ emissions within that range depends on the type of fuel source and the period over which the emission rate would be averaged.

Under Section 111(d) of the Clean Air Act, the EPA was required to propose standards for existing power plants which it did on June 2, 2014 via the Clean Power Plan. On August 3, 2015, the EPA finalized the rules, or standards, that will guide state’s toward reducing their CO₂ emissions. In its proposed Clean Power Plan to reduce CO₂ emissions in the power sector to 30 percent below 2005 levels by 2030, the EPA has set a unique target emissions rate for each state to hit by 2030.
When developing targets, the EPA first determined CO₂ emission baselines dividing each state’s 2012 CO₂ emissions from fossil fuel-fired power plants by its 2012 electricity generation (including fossil fuel-fired generation, renewable generation, and nuclear generation). Targets for 2030 were then established based on the capacity of each state to achieve reductions using the following three building blocks identified by the EPA:

1) reduce the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants
2) substitute increased electricity generation from lower-emitting existing natural gas plants for reduced generation from higher-emitting coal-fired power plants
3) substitute increased electricity generation from new zero-emitting renewable energy sources (like wind and solar) for reduced generation from existing coal-fired power plants

Each state can meet its established target however it sees fit, and does not need to leverage each building block to the extent that the EPA has projected for each state. States will be able to convert their targeted emissions rates provided by the EPA, in pounds of CO₂ emitted per megawatt-hour of electricity generated, into a mass-based standard (tons of CO₂ emitted per year) to facilitate participation in a cap-and-trade programs. States are also free to join together to work toward aggregated regional targets.

On February 10, 2016, the Supreme Court placed a hold on the Clean Power Plan, which will stay in place until a lower court rules on the merits and the Supreme Court either refuses to hear the case or rules on the merits. This hold is likely to last for approximately 18 months, depending upon how quickly the appellate process proceeds.

**Clean Air Rule**

In 2008, House Bill 2815 (“HB 2815”) was passed by the Washington legislature. HB 2815 adopted emission reduction targets that called for the state to limit its GHG emissions by returning to 1990 levels by 2020, cutting emissions 25 percent below the 1990 levels by 2035, and reaching 50 percent below 1990 levels by 2050. In July 2015, Governor Jay Inslee directed the Department of Ecology to develop a rule to cap and reduce greenhouse gases in Washington under our state’s Clean Air Act.

On June 1, 2016, the Washington State Department of Ecology rolled out an updated plan to cap GHG emissions from the state’s largest emitters. The plan is a modified version of the original plan that was proposed in late 2015 and withdrawn on February 26, 2016. The Clean Air Rule is scheduled to be finalized and adopted in September 2016 and will become effective in 2017.

Under the Clean Air Rule, natural gas distributors, petroleum fuel producers and importers, large manufacturers, electricity generating plants, waste facilities and other organizations that are responsible for more than 100,000 metric tons of GHG per year will be required to reduce their
emissions or sponsor projects to offset those emissions. Every three years, the threshold will be lowered by 5,000 metric tons and more emitters brought into the program until 2035 when the threshold will reach 70,000 metric tons per year. Organizations covered under the rule will be required to reduce their emissions by an average of 1.7 percent each year, beginning from a baseline determined by their average emissions between 2012 and 2016.

Organizations covered by the rule will have several options to meet their reduction requirements. Some facilities may find efficiencies that go beyond their reduction requirements. These businesses could trade or sell their excess reductions to other emitters in the program. Alternatively, an organization in the program could fund projects that reduce carbon pollution in the state, such as dairy digesters, renewable power, or commute trip reduction plans. They could also purchase allowances from other established multi-sector carbon markets as approved by the Department of Ecology. Initially the approved carbon markets will likely be limited to those run by California and Alberta.

Generating plant owners could comply by reducing generation so that GHG emissions are less than they otherwise would be in a given year. Plant owners could also comply by offsetting emissions with RECs or external allowances. Under the current proposal 2.25 RECs would be equivalent to one metric ton or 2,200 pounds of GHG.

The Clean Air Rule will fall short of the target established by HB 2815 for 2035. HB 2815 requires GHG emission levels to be 25 percent below 1990 GHG emission levels by 2035. The Clean Air Rule would result in GHG emission levels that are 15 percent below 1990 levels. As such, the state will need to take additional actions to meet the target as shown in Exhibit 14 below.

**Exhibit 14**

CO₂ Emissions under Clean Air Rule

![Graph showing CO₂ emissions over time under Clean Air Rule.]

Source: State of Washington Department of Ecology
Initiative-732

Initiative-732 ("I-732") would reduce the state’s sales tax by one percent, reduce the Business and Occupation ("B&O") tax on manufacturing and implement and enhance the existing working families’ sales tax exemption for qualifying low income persons. These reductions to the state’s revenue stream would be offset by a carbon tax on fossil fuels sold or used in the state and on the consumption or generation of electricity generated by fossil fuels in the state. This includes electricity that is generated in other states and imported into the state via transmission lines. The carbon tax would cover the carbon content of imported electricity through reports similar to the fuel mix disclosure reports utilities are currently required to file with the state, but otherwise it would focus only on fossil fuels consumed in the state of Washington.

The carbon tax rate would be $15/ton beginning upon implementation in July 2017 and increase to $25/ton in July 2018. In all subsequent years the tax rate would increase by 3.5 percent plus the rate of inflation. The tax rate is not to exceed $100 per ton in 2016 dollars.

The initiative’s proponents have stated that they expect CO₂ emissions to decrease by 2 percent per year and that the plan is revenue neutral. Revenue neutral means that any revenue generated by the carbon tax would be returned to state residents through various tax cuts. The proponents estimate that the carbon tax would generate $1.7 billion annually in carbon tax revenue to state which would be fully offset by decreases in sales and B&O tax revenue and enhancements to the working families’ sales tax exemption. A recent analysis by the state estimates that the carbon tax may reduce the state’s overall tax revenue by $675 million over the four-year period 2018 through 2021.

Over the next year, it is possible that more than one carbon-pricing law could be enacted in Washington, but a carbon tax may face political challenges if another plan becomes law first.

Natural Gas-Fired Combustion Turbines

Fuel costs typically represent 60 to 80 percent of combustion turbine ("CT") project costs. Natural gas prices are currently low by historic standards due to new technologies in hydraulic fracking that have significantly increased the supply of natural gas available in North America. Exhibit 15 below shows the range of U.S wellhead natural gas price forecasts proposed for the 7th Power Plan. As shown in the graph natural gas prices doubled between 2002 and 2008 and have declined significantly since 2008.
The high natural gas price forecast recognizes the possibility that demand may outstrip supply in the future due to limited supplies. The potential for limited supplies could be increased by rapid world economic growth and the possibility that gas-fired resources will be ‘bridge resources’ in carbon constrained world until new technologies address emissions. In several states (e.g. Oregon, Washington and California), legislative mandates will drive utilities away from coal in favor of natural gas-fired resources. An abundance of new natural gas-fired generating stations located on the west coast could drive up natural gas market prices. The low case assumes slow world economic growth which reduces the pressure on energy supplies.

Two primary CTs are considered in typical resource studies. The first is a simple-cycle combustion turbine (“SCCT”), and the second is a combined-cycle combustion turbine (“CCCT”). The primary difference between the two technologies is that the CCCT recovers the waste steam that is lost in a simple-cycle and uses this energy to turn an additional steam turbine. In base-load operations, a CCCT is preferred because of its greater thermal efficiency and lower cost on a per unit basis. A SCCT is more appropriate to ramp generation levels up and down to meet peak loads.

Coal

Coal combustion is one of the oldest and most well established methods of generating electricity. Due to environmental regulations of the air emissions and other environmental impacts
associated with coal-fired power plants, very large central station plants (1,000 megawatts or more) are no longer considered to be economically efficient.

In September 2007, Substitute Senate Bill 6001 (“SSB 6001”), enacted by Washington State established statewide Green House Gas (“GHG”) emissions reduction goals, and set an emissions performance standard on base load electric generation. The law imposes significant restrictions on the procurement of fossil-fuel-fired base load generation. Conventional coal-fired generation (i.e., pulverized coal) produces GHG emissions in excess of the new emissions standard of 1,100 pounds of carbon dioxide per megawatt hour. The law effectively bars utilities in Washington State from entering into long term financial commitments for coal-fired generation unless they use some form of carbon sequestration.

New coal combustion technologies, such as Integrated Gasification Combined Cycle (“IGCC”) technology with the ability to capture carbon for sequestration may be viable resource options in the future. IGCC technology is a coal-fired, combined cycle electric power generation technology with post-combustion emission controls. The four major processes in an IGCC facility are: 1) converting coal into a fuel gas, 2) cleaning the fuel gas, 3) using the clean fuel gas to fire a gas turbine generator and the hot turbine exhaust to make steam that drives a steam turbine generator, and 4) treating waste streams. Gasification of coal allows pollutant carriers to be removed from the fuel before combustion in the power plant. Emissions of sulfur and nitrogen oxides and particulates from IGCC facilities are projected to be significantly lower than for traditional coal technologies. However, a viable carbon sequestration plan must be formulated which, to date, has not yet been effectively demonstrated.

Plans to build new coal-fired plants have decreased significantly over the past decade. According to the Sierra Club, since 2002, there have been more than 183 cancellations of planned coal plants in the United States. The cancellations have been due to escalating project costs, permitting problems and most importantly uncertainties regarding state and federal legislation that may result in significant increases in the costs associated with coal-fired generation. In addition to cancellations, according to the Sierra Club, 200 coal plants, or nearly 40 percent of the 523 coal plants that were in operation five years ago, have been shut down since 2010. Coal plant shutdowns are likely to continue due to low natural gas prices and new EPA rules regulating air pollution.

Nuclear

Due to the long lead-time, development and permitting timeframe and issues related to the disposal of spent fuel, the potential for the development of a new large scale nuclear power plant is unlikely. In addition, three nuclear power accidents have influenced the discontinuation of nuclear power: the 1979 Three Mile Island partial nuclear meltdown in the United States, the 1986 Chernobyl disaster in Russia, and the 2011 Fukushima nuclear disaster in Japan. Following the March 2011 Fukushima nuclear disaster, Germany permanently shut down eight of its 17 reactors and pledged to close the rest by the end of 2022. Italy voted overwhelmingly to keep
their country non-nuclear. Switzerland and Spain have banned the construction of new reactors. Japan’s prime minister has called for a dramatic reduction in Japan’s reliance on nuclear power.

In the United States, two nuclear plants have shut down in the past two years because they could not compete with the lower running costs of natural gas projects. A third plant, the San Onofre Nuclear Generating Station ("SONGS"), shut down due to the failed replacement of steam generators. It should be noted that when nuclear plants shut down, carbon dioxide emissions increase in a region. During the year after the SONGS shutdown carbon dioxide emissions in California increased by 9 million tons or the equivalent of 2 million automobiles.

BPA’s Tier 1 resource pool includes the 1,190 megawatt Columbia Generating Station ("CGS"), a nuclear power plant that began operating in 1984. CGS is the only commercial nuclear energy facility in the region. All of its output is provided to BPA at the cost of production under a formal “net billing” agreement in which BPA pays the costs of maintaining and operating the facility.

**Small Scale Modular Reactors**

NuScale Power LLC will submit an application to the Nuclear Regulatory Commission in 2016 for a 50-megawatt nuclear power module. The application will begin a 39-month review process that, if successful, would result in project approval by 2020. The modules can be combined in 12-part units producing as much as 600 megawatts. The systems are built in a factory and are scalable such that utilities can add modules as loads increase. NuScale is backed by the U.S. Department of Energy, which has awarded more than $217 million to develop small scale nuclear modular reactor technology as a clean alternative to fossil fuels.

Utah Area Municipal Power System ("UAMPS") selected NuScale and partner Energy Northwest to construct a small scale nuclear modular plant in Idaho, near the Department of Energy’s Idaho National Energy Laboratory near Idaho Falls. The UAMPS project would be the first of its kind in the region.

Energy Northwest representatives have said that their experience with the plant in Idaho may lead the way toward siting a small modular reactor somewhere in the Tri-Cities. Small modular reactor advocates would also like to start a manufacturing plant in Richland, where the reactors would be able to be shipped around the world. Given the region’s historical experience with nuclear power and the presence of ENW, the Tri-Cities would likely be first on the list of potential locations to site a small nuclear reactor in Washington. GHPUD should closely track ENW’s activities. Modular reactors may provide a valuable carbon-free resource for serving future GHPUD’s above-HWM load.

**Renewable Energy Overview**

The benefits of renewable energy projects such as wind and solar lie in the expectation that the projects have environmentally appealing aspects. In addition, eligible renewable projects can provide protection against fuel price and carbon cost risks and provide diversification of fuel
consumption thereby limiting the risks associated with relying on one type of fuel and the volatile nature of fuel prices.

Due to Renewable Portfolio Standard (“RPS”) requirements in Washington state and elsewhere in the region (California, Oregon and Montana) there was competition for wind projects during the period 2006 through 2012. However, as shown in Exhibit 12 above, wind project development has slowed in recent years. Most utilities have addressed their short- and mid-term RPS requirements. There is a risk that, due to the increasing RPS targets large utilities must achieve, large utilities in the Northwest and in California may be purchasing much of the supply of the least cost/high capacity factor wind projects. With large utilities purchasing large amounts of renewable generation and competition from out of region utilities with increasing RPS requirements (such as Oregon and California), it may be difficult for small- and medium-sized utilities, such as GHPUD, to find enough megawatts to fulfill the requirements. There are a great number of uncertainties surrounding state renewable energy purchase requirements and the impact on eligible renewable generation available in the market.

Since 2005, various tax credits have been available to encourage the development of renewable generation. Each tax credit is discussed below. Until December 2013, tax credit deadlines had historically been extended by Congress. In December 2013 Congress did not extend the production tax credits for projects not under development. It is unclear if this Congress will act to reinstate the tax credits.

The Energy Policy Act of 2005 provided for the renewal of the Production Tax Credit (“PTC”) for wind resources placed in service by December 2007. Since then, the PTC has been extended several times such that the PTC currently provides a credit of 2.3 cents per kWh (2016 dollars) of actual energy generated applicable to the first 10 years of operation. In December 2015, the expiration date for the full tax credit was extended to apply to wind facilities that commence construction before December 31, 2016. The tax credit will be phased down beginning in 2017 but will, on a reduced basis, be available to wind facilities that begin construction between January 1, 2017 and December 31, 2019. The tax credit was extended for other eligible renewable energy technologies that commence construction before December 31, 2016.

Investment Tax Credits (“ITC”) are similar to the PTC except that a share of project expenditures is available as a tax credit up front (rather than over the course of 10 years like the PTC). The ITC applies to solar, fuel cells, small wind turbines, geothermal, micro-turbines, and combined heat and power. Depending on the technology and timing of investment, it may be more beneficial for developers to pursue the ITC rather than the PTC. Based on current regulations, the current 30 percent credit is available to eligible wind facilities placed in service on or before December 31, 2016, after which time the credits ramps down by 6 percent per year until it expires on December 31, 2019. The credit for equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat is 30 percent through 2019. The credit will gradually decrease from 30 percent to 10 percent in 2022 where it will stay. The 10 percent credit currently available for geothermal heat pumps, hybrid
solar lighting, small wind, fuel cells, micro-turbines, and combined heat and power systems will expire on December 31, 2016. The current credit amount for equipment which uses geothermal energy to produce electricity will remain at 10 percent (does not expire).

The federal Renewable Energy Production Incentive (“REPI”) provides incentive payments similar to the PTC for electricity produced and sold by new qualifying renewable energy facilities owned by not-for-profit electrical cooperatives, public utilities and state governments. Qualifying systems are eligible for annual incentive payments for the first 10-year period of their operation just like the PTC; however, REPI benefits are subject to the availability of annual appropriations in each federal fiscal year of operation. Unfortunately, the REPI program has been under-funded in recent years, with appropriations so low that utilities have not been able to utilize the program.

Wind

Wind turbines convert wind energy into electricity by collecting kinetic energy generated when the blades that are connected to a drive shaft (rotor) turn a turbine generator. Individual wind turbines typically have a capacity of near 2.5 megawatts. Wind generation facilities typically range in size from 50 to 300 megawatts.

Wind generation developed rapidly in the Pacific Northwest over the past decade as shown above in Exhibit 12. Currently there is near 9,000 megawatts of capacity from wind projects installed in the Pacific Northwest. According to the Northwest Power Planning and Conservation Council only 240 megawatts of wind is currently under construction. However, assuming that issues related to the availability of transmission service and the ability to manage the intermittency and unpredictability of the output can be resolved as more wind is developed, wind will be a viable and feasible renewable resource in the future.

The average capacity factor of a wind project located in the Northwest is near 30 percent. The average capacity factor of a wind project located in eastern Montana is near 38 percent. Due to transmission constraints, almost all of the wind projects developed over the past decade have a capacity factor of near 30 percent.

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. The fact that wind power generation is variable, and not wholly predictable, means that electricity system operators must provide additional reserves to counter the additional risk in balancing power supply and demand. In addition, wind power output may not be available when it is most needed such as during summer heat waves, or winter arctic outbreaks, when wind turbines are notorious for low generation levels due to reduced wind velocities.

Since wind output cannot be assumed to be available in all hours, other generating resources need to be on call to be ramped down when wind resources provide generation and ramped up when wind resources do not provide generation. Providing within-hour balancing services for variable wind power, including additional reserve capacity and shifting generation patterns is
known as wind integration. Typically, this requires larger utilities that operate control areas to use dispatch-able resources to balance total generation and total load. Currently, the capacity and flexibility for balancing intermittent wind in BPA’s Balancing Authority Area comes almost entirely from the Federal Base System.

According to the 7th Power Plan the projected 20-year (2016-35) levelized cost of wind energy in the Northwest ranges from $105 per megawatt-hour for a project with a 38 percent capacity factor to $124 for a project with a 32 percent capacity factor.

**Utility-Scale Solar**

Solar energy is the direct harnessing of the sun’s energy. The major issues to overcome with respect to solar energy are: 1) the intermittent and variable manner in which sun energy arrives at the earth’s surface and 2) the large area required to collect the sun’s energy at a useful rate. In the case of solar Photovoltaic (“PV”) systems, the process is direct, via silicon-based cells. In the case of solar concentrating thermal, the process involves heating a transfer fluid to produce steam to run a generator. Both of these technologies are discussed below.

PV systems use PV cells to convert sunlight into direct current electricity. PV cells are made from silicon and come wired together in 4 feet by 1 foot by 1.5-inch-deep panels. A group of panels mounted on a frame is called a PV array. There are numerous large-scale PV projects installed around the world. These installations include all sizes of commercial and public facilities (from a few to several hundred megawatts). A typical capacity factor for a PV system is near 20 percent.

Another kind of solar technology known as Concentrating Solar Power (“CSP”) has been in development phase for many years. CSP technologies use reflective materials such as mirrors to concentrate the sun’s energy and convert it to electricity. CSP technologies are more efficient (approximately 30 percent capacity factor) than PV and have the potential to be more cost-effective and practical than PV for centralized plants. The general types of CSP technologies are:

- **Dish Systems:** A dish system uses a mirrored dish (similar to a very large satellite dish) which collects and concentrates the sun’s heat onto a receiver, which absorbs the heat and transfers it to fluid within an engine. The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

- **Parabolic Troughs:** Parabolic-trough systems concentrate the sun’s energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity.

- **Power Towers:** A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits. This heats molten salt flowing through the receiver. Then, the salt’s heat is used to generate electricity through a conventional steam
generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.

- Concentrating Photovoltaic: Concentrating PVs use optics to concentrate sunlight onto a small area of solar cells. These photovoltaic cells convert the light into electricity. Most concentrators use tracking capability that allows concentrators to take advantage of as much daylight as possible from dawn until dusk.

CSP projects have higher costs than PV systems and take more time to construct. Due to these factors, CSP projects are most likely to be built in the Southwest. The relatively high costs and investment risk of long distance transmission needed for the output of the highly efficient plants to reach Northwest load centers have made them less attractive in the Northwest.

The national solar energy market is changing rapidly. Over 5,000 megawatts of solar capacity was added in the U.S. in 2014. The cost of both small and large scale solar projects has been steeply declining over the past decade. The current cost of utility-scale solar PV is near $3/watt. The U.S. Department of Energy’s SunShot Initiative was launched in 2011 in order to coordinate scientific efforts at reducing the cost structure of solar power. The goal of the initiative is to reduce solar PV costs to $1/watt by 2020 for utility scale, $1.25/watt for commercial rooftop, and $1.5/watt for residential rooftop.

The reference case forecast in the 7th Power Plan shows utility-scale costs declining to $2.2/watt, well short of the SunShot Initiative’s goal, but still a near 30 percent cost reduction in only 6 to 7 years. In addition to declining equipment costs there are several subsidies and incentives that decrease the cost of solar in the state of Washington.

The increased attention on carbon emissions from traditional power generation sources, and on U.S. energy independence, is also motivating retail customers and utilities to re-evaluate solar PV. Because of this growing convergence of interests and reduced cost, it is prudent to investigate the potential for utility involvement in utility-scale solar projects.

Due to relatively low solar generating capacity, the cost effectiveness of solar is, however, reduced in Washington state compared to locations like southern California or Arizona. Exhibit 16 below demonstrates that solar generation is not an ideal match for GHPUD’s residential loads.
Exhibit 16
Typical Monthly Residential Rooftop Solar Generation and Load (kWh)

The blue line in Exhibit 16 above shows the typical seasonal load of a residential customer in GHPUD’s service territory compared to the typical output expected from a 6 kW rooftop solar installation. As shown above loads exceed solar generation in all months except July and August during which solar generation and loads are a relatively good fit. However, generally speaking, the seasonal shape of GHPUD’s loads is the opposite of the seasonal shape of solar generation and due to low solar generating potential, in October through March the generating capability of a typical 6 kilowatt installation is less than half the load of a typical residential home. The same mismatch of load and generation shapes would apply to a utility scale solar (greater than 1 MW) located in Grays Harbor’s service territory.

According to the 7th Power Plan the 20-year (2016-35) levelized cost of utility scale solar PV projects in the Northwest is projected to be $112 per megawatt-hour.

**Battery Storage Systems**

Large-scale energy storage doesn’t exist today beyond massive pumped hydro projects (a discussion of pumped hydro is included below). Only California provides financial incentives for energy storage devices. In addition, California state law requires utilities to start buying batteries...
that can store renewable energy. The law requires the state’s three investor-owned utilities to add 1.3 gigawatts of energy storage to the grid by 2020. The law also includes a rule that utilities may own no more than half of the storage assets they procure. That opens the path for a massive growth of merchant storage, customer-owned energy assets and other arrangements. The law was designed to encourage the development of an unprecedented number of batteries, thermal energy storage and other forms of grid power and energy capture-and-release technologies, all while adhering to the mandate’s requirement that they be “cost-effective”. Due to the activity in California utilities should expect to see growth of merchant storage, customer-owned assets and other storage project arrangements.

Lithium-ion batteries have the greatest potential storage capability and efficiency (e.g. for solar and wind integration) as shown below in Exhibit 17.

Complementing solar systems with battery storage systems could have many advantages. Storage systems have the potential to help solve some of the larger-scale problems associated with connecting lots of intermittent, on-again, off-again solar power to the grid. For example,
energy storage could help mitigate the distribution grid voltage sags and surges that can occur when clouds pass over neighborhoods with lots of rooftop solar.

Storage systems could allow utilities to reduce wholesale market purchases when prices spike. If utilities were able to control the use of the storage systems, they could store energy during low market price periods and use the energy during high market price periods.

Storage systems could also provide short-term solutions to transmission system constraints. BPA includes “demand reduction initiatives” in its non-wires solutions to building new transmission lines. Storage systems have the potential to reduce demand to the financial benefit of BPA and its customer utilities. Distribution and/or transmission system upgrades could be delayed if storage systems allowed utilities to reduce their peak loads. Exhibit 18 below illustrates how a 50 megawatt utility-scale solar system and a 10 megawatt lithium ion battery system with a discharge capability of megawatts could work together to reduce system peak load.

**Exhibit 18**

Example of Utility Scale Solar PV and Battery Storage System

![Graph of utility scale solar PV and battery storage system](source: Northwest Power and Conservation Council’s Draft 7th Power Plan)

Despite the apparent momentum battery systems have in the utility industry, to date the cost of battery systems has been too expensive to justify. Simply put, batteries are too expensive, and the price of power is too low to justify the expense. As such, storage systems are currently not
cost effective (utility-scale and smaller). Below is a comparison of how the costs of pumped storage and flow batteries compare to BPA’s demand rate (paid by BPA customers that are served under a load following contract):

- BPA demand rate ≈ $10/kW-mo
- Lifecycle costs of pumped storage ≈ $30/kW-mo
- Lifecycle cost of flow battery ≈ $50/kW-mo

Battery system costs are expected to decrease over next 5 to 10 years much in the same way that solar PV system costs are expected to continue to decrease. As shown below, the estimated cost of storage systems is expected to decline significantly by 2020:

- Pumped hydro and gas peakers = $100 - $300/MWh
- 1 MW lithium ion = $550/MWh (projected 2020 = $200/kWh)
- 1 MW vanadium redox flow batteries = $680/MWh (projected 2020 = $350/MWh)

Smaller battery systems that could be combined with rooftop solar systems have higher costs.

At this time the only way to make a battery storage system cost-effective is to secure grant money. The Washington State Legislature has approved funding to create a Clean Energy Fund to advance clean energy projects and technologies throughout the state. These “smart grid” grants are awarded to competitively chosen applicants and selection is based on the likelihood of a project’s ability to demonstrate improvement in the reliability and/or lowered cost of distributed or intermittent renewable energy. Clean Energy Fund 1 (2013-15) set aside $15 million and awarded funds to three utilities to develop lithium ion/phosphate and vanadium flow batteries as well as two demonstration projects for energy storage control and optimization projects known as Modular Energy Storage Architecture or MESA. The State appropriated $13 million for new smart grid technologies for Clean Energy Fund 2. The State has not yet awarded funds for all Clean Energy Fund 2 programs.

**Geothermal**

Geothermal projects, like wind and solar, have little or no carbon dioxide emissions. Unlike solar and wind projects geothermal projects have relatively high capacity factors and can be used as base-load resources.

In conventional geothermal plants, geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir.
Enhanced geothermal systems stimulate or fracture rock in order to allow fluid flow and heat transfer. Water is then pumped down and run through the fractures to collect heat. A production well connects to the created reservoir and completes the loop by bringing the heated fluid to surface in order to drive a steam turbine that generates electricity. Enhanced geothermal systems are considered an emerging technology as there are no commercially proven projects in operation.

Current U.S. geothermal electric power production totals approximately 3,400 megawatts of installed capacity. The largest group of geothermal plants in the world is located in The Geysers, a geothermal field in California. The Geysers includes 22 geothermal power plants with a total capacity of 1,517 megawatts of installed capacity. The 13 megawatt Raft River project in southern Idaho became the first commercially operational geothermal project in the Northwest when it began operations in January 2008. The 28.5 megawatt Neal Hot Springs project in southeastern Oregon is the largest geothermal plant operating in the Northwest.

A U.S. Geological Survey assessment identified roughly 950 average megawatts of potential resource in the Northwest. Geothermal generation in the Northwest is, however, still in the initial stages of commercial exploration and development. High development and exploration costs are substantial barriers to the future development of geothermal sources for power production. The location of potential geothermal sources in environmentally sensitive areas has been a barrier to siting geothermal power facilities in the Northwest.

Potential geothermal resources in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with the volcanoes of the Cascade mountain range. Geothermal development in the Northwest has historically been constrained by high-risk, low-success exploration and well field confirmation. In addition, most of these locations are remote and would require significant transmission investments to facilitate transmitting the power to load centers.

According to the 7th Power Plan the projected 20-year (2016-35) levelized cost of geothermal energy in the Northwest ranges from $175 to $240 per megawatt-hour.

Wave Power

Wave energy is the result of the capacity of waves to do work. Ocean waves are generated by the influence of the wind on the ocean surface first causing ripples. As the wind continues to blow, the ripples become chop, then fully developed seas, and finally swells. In deep water, the energy in waves can travel for thousands of miles until that energy is finally dissipated on distant shores.

There are three main types of wave energy technologies. One type uses floats, buoys, or pitching devices to generate electricity using the rise and fall of ocean swells to drive hydraulic pumps. A second type uses oscillating water column devices to generate electricity at the shore using the
rise and fall of water within a cylindrical shaft. The rising water drives air out of the top of the shaft, powering an air-driven turbine. Third, a tapered channel, or overtopping device can be located either on or offshore. These devices concentrate waves and drive them into an elevated reservoir, where power is then generated using hydropower turbines as the water is released.

The vast majority of recently proposed wave energy projects would use offshore floats, buoys or pitching devices.

According to a recent study by researchers from the University of Victoria, Oregon State University and private industry large-scale and geographically diverse wave-energy systems off the Northwest coast would have modest grid-integration costs, and would generate power fairly predictably. By producing wave energy from a range of different sites, possibly with different types of technology, and taking advantage of the comparative consistency of the wave resource itself, it appears that wave energy integration should be easier than that of wind energy. According to the study the reserve, or backup generation, necessary for wave energy integration should be minimal. The modeling assumed capacity factors of 30 to 35 percent.

According to the 7th Power Plan the projected 20-year (2016-35) levelized cost of wave energy in the Northwest is $313 per megawatt-hour.

**Tidal**

Tidal in-stream energy is created by harnessing the power of the moving mass of water caused by the gravitational forces of the sun and the moon, and the centrifugal and inertial forces on the earth’s waters. The gravitational forces of the sun and moon and the centrifugal/inertial forces caused by the rotation of the earth around the center of mass of the earth-moon system create two “bulges” in the earth’s oceans: one closest to the moon, and the other on the opposite side of the globe.

Built in 1966, the Rance tidal power plant in northern France was the first tidal power station in the world. Total turbine capacity of the project is approximately 240 megawatts. This type of tidal power generation requires construction of a huge dam called a “barrage” which is built across an estuary. When the tide goes in and out, the water flows through tunnels in the dam. The ebb and flow of the tides is used to turn a turbine, or it can be used to push air through a pipe, which then turns a turbine. Large lock gates, like the ones used on canals, allow ships to pass. The largest tidal power plant in the world, the 254 megawatt Sihwa Lake tidal power plant in South Korea, began operating in 2011.

More recent technology, known as tidal in-stream energy conversion (“TISEC”) devices, use tidal current to drive turbines coupled to electrical generators. A typical tidal power plant involves a farm of multiple, underwater TISECs. Depending on the TISEC technology, the TISEC unit can be either rigidly fixed in place under the water surface or it may float inside the water column, tethered to a cable attached to the sea floor. This technology is evolving through a pre-commercial research phase but is expected to be commercially available within the next decade.
There are several locations in the Puget Sound area that have potential for tidal energy. However, due to funding challenges and the lengthy permitting and licensing process, to date, no pilot tidal energy projects have been deployed in the Puget Sound area.

**Pumped Storage**

Pumped storage is a type of hydroelectric power generation that stores energy in the form of water in a reservoir pumped from a second reservoir at a lower elevation. Water is pumped from the lower reservoir during periods of excess supply and the stored water is released during periods of high electricity demand. Traditionally, pumped storage plants were used to balance load on a system and allow large thermal generating sources to operate at optimal conditions. Pumped storage is the largest capacity and most cost-effective form of energy storage currently available. Pumped storage is being evaluated in several areas as a possible solution to providing balancing services to wind projects.

Seventeen pumped storage projects with more than 4,700 megawatts of capacity in aggregate are installed on the west coast. The only pumped storage project located in the Northwest is the 314 megawatt John W. Keys III Pump-Generating Plant that pumps water from the Franklin D. Roosevelt Lake behind Grand Coulee dam 280 feet uphill to Banks Lake. Water in Banks Lake is used for agricultural irrigation and power generation.

During spring months in the Northwest, hydroelectric resources produce significant amounts of energy from spring run-off. At the same time, windy spring conditions results in large quantities of wind energy available at the same time when demands for electricity are low. This oversupply of energy has been resolved in the past by generation curtailment, which can be highly contentious and disruptive. Pumped storage may become the energy storage solution of choice as more wind is added to the balancing area and curtailments increase. During periods of high wind and high water, water is pumped to a storage reservoir using wind energy to power the pumps. The water is then released through the hydroelectric facility once demand increases or there is less generation from wind resources. The cost-effectiveness of pumped storage is determined by the price differential between heavy load hours (high demand) and low load hours (low demand). The efficiency of the pumps and hydroelectric generators are also an important factor. As facilities become more efficient and require less energy, the cost-effectiveness increases. Generally, however, pumped storage is a net consumer of energy in that it takes more energy to pump the water uphill than is recouped in the generation process when the water is released through the generator. Exhibit 19 below shows a depiction of a pumped storage power plant.
According to the 7th Power Plan, there are 17 projects with existing FERC permits located in the Northwest. However, only two of the 17, EDF Renewable Energy’s Swan Lake North Pumped Storage Project and the Banks Lake North Dam Pump/Generation Project, are in active development. Swan Lake North is a proposed 400 MW pumped storage project located in Klamath County, Oregon. The project could begin construction as soon as January 2019 and be commercially operational by January 2023. Banks Lake North is a proposed 1,000 MW pumped storage project located near Grand Coulee Dam on the Columbia River in Washington state. The target date for project completion is 2025.

One of the issues with pumped storage projects is that the projects are usually larger in size than the needs of a single entity. Finding multiple parties that are willing to commit to long-term financing can be difficult.

Costs for pumped storage facilities vary by site. According to the draft 7th Power Plan the estimated cost for new pumped storage projects ranges from $1,800 to $3,500 per kilowatt of installed capacity. The range in cost is driven by the length of the tunnel needed for the project, the amount of overall head (the lower the head, the higher the costs), the amount of above ground infrastructure required, and the variable speed technology selected for the pump/turbines.

### 20-Year (2017-36) Levelized Costs

Exhibit 20 below summarizes the nominal levelized costs of the supply-side resources discussed above. The 20-year levelized cost of energy efficiency is per GHPUD’s 2015 CPA. Forecast BPA Tier 1 rates are included for comparison purposes. Forecast BPA Tier 1 rates are from BPA’s reference case in its on-going Focus 2028 forum. The costs of all other resources are based on the operation and maintenance and capital costs included in the 7th Power Plan. Since BPA’s Tier
2 load growth rates are based on market purchases made at market prices, Tier 2 rates should be considered to be equal to the “market” price shown below. The reference case “biomass” project in the 7th Power Plan is woody-residue.

Not surprisingly, Exhibit 20 shows that the wholesale market and energy efficiency are the lowest cost resources followed by BPA Tier 1 rates. The wholesale market price forecast is simply a forecast of market prices at a point in time. Market prices are highly dependent on natural gas prices, the capability of the hydro system in a given year and many other factors. In addition to price volatility, relying on market purchases to serve load would expose GHPUD to uncertainty with respect to the availability of power that can be shaped to serve GHPUD loads and has a contract term that meets GHPUD’s requirements. The availability of market power is not guaranteed as most of the region’s current firm surplus is held by marketers who are free to sell the power to highest bidder, including the California market (assuming there are no transmission constraints).

The Tier 1 rate shown above includes costs associated with load shaping and demand purchases and, as such, represents a power purchase that follows a load following BPA customer’s daily, monthly and seasonal loads. Market prices are representative of the cost of a flat block of power that could not be used to serve load. As such, a comparison of Tier 1 rates to market prices is not an apples-to-apples comparison.
Local Resources

Potential distributed generation projects in GHPUD’s unique service territory will be considered in this section. The resources included in this discussion are listed below:

- Rooftop Solar
- Community Solar
- Batteries
- Demand Response Units
- Landfill Gas
- Anaerobic Digesters
- Biogas - Wastewater Treatment Plants
- Biomass Woody Debris
- Micro-Hydro

The environmental impact and potential risks and rewards of each resource option must be considered as well as the constraints or limitations of each technology. For example, recent data on the impact of rooftop solar on voltage stability within distribution systems will be discussed.

Distributed Generation Overview

This section of the report addresses the potential for local, distributed generating resources that would decrease GHPUD’s dependence on the wholesale transmission system for delivering power to serve GHPUD’s load.

Washington State Net Metering Law

Washington's net-metering law applies to systems up to 100 kilowatts of capacity that generate electricity using solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). All customer classes are eligible, and all utilities -- including municipal utilities and electric cooperatives must offer net metering.

Utilities may not charge customers any additional standby, capacity, interconnection, or other fee or charge without approval from the Washington Utilities and Transportation Commission. As a public utility, GHPUD’s governing board could hold a hearing to determine there is a need for additional charge(s) and implement such charges as needed.

Taking advantage of Washington's Renewable Energy Production Incentives (discussed below) does not reduce or impact the kilowatt-hour savings achieved through net metering. However, utilities may require separate metering to track production, and customers must pay all costs associated with the installation of production meters. While the ownership of renewable energy
credits ("RECs") associated with generation is not specified in the state's net-metering law, the production incentive law states that customer-generators retain ownership of RECs.

**Incentives Available to Renewable Resources**

Below is a discussion of the incentives available to renewable resources in GHPUD’s service territory. It should be noted that the incentives discussed below are representative of those currently available. Changes to the incentives will likely be proposed during the next legislative session.

**Washington Renewable Energy Production Incentive**

In May 2005, Washington enacted Senate Bill ("SB") 5101, establishing production incentives for individuals, businesses, and local governments that generate electricity from solar power, wind power or anaerobic digesters. The amount of the incentive paid to the producer starts at a base rate of $0.15 per kilowatt-hour (kWh) and is adjusted by multiplying the base rate incentive by the following multipliers:

- For electricity produced using solar modules manufactured in Washington state: 2.4
- For electricity produced using a solar or wind generator equipped with an inverter manufactured in Washington state: 1.2
- For electricity produced using an anaerobic digester, by other solar equipment, or using a wind generator equipped with blades manufactured in Washington state: 1.0
- For all other electricity produced by wind: 0.8

These multipliers result in production incentives ranging from $0.12 to $0.54/kWh, capped at $5,000 per year. Ownership of the RECs associated with generation remains with the customer-generator and does not transfer to the state or utility.

In May 2009 Washington’s legislature passed SB 6170. With the passage of this legislation, community solar projects became eligible to receive the production incentive. Community solar projects are defined as solar energy systems up to 75 kilowatts that are owned by local entities and placed on local government property or owned by utilities and funded voluntarily by utility ratepayers.

Per the legislation utility-owned projects are excluded from receiving the production incentives if the utility has annual sales greater than 1,000 megawatt-hours. In June 2009, the Department of Revenue clarified this exclusion, stating that utility-owned community solar projects that are voluntarily funded by rate-payers are eligible for this production incentive. This ruling was formalized with the passage of SB 6658 in March 2010. This legislation also allows projects on local government property that are owned by limited liability companies, cooperatives, or mutual corporations or associations to receive the incentive. The company itself is not eligible, but owners may take advantage of the incentive.
The base rate for community solar projects is $0.30/kWh and the multipliers are the same as those used for other renewable energy technologies. The actual production incentives range from $0.30/kWh to $1.08/kWh, with greater incentive rates for systems with modules and inverters manufactured in Washington. The incentive is capped at $5,000 per year. Each participant in a community solar project, or each owner of a project, can apply to receive this incentive and may receive up to $5,000 per year.

The state's utilities pay the incentives and earn a tax credit equal to the cost of those payments. SB 6170 also increased the tax credit that utilities may claim for awarding production incentives. Previously, the credit could not exceed the greater of $25,000 or 0.25 percent of a utility's taxable power sales. Now, the credit cannot exceed the greater of $100,000 or 0.5 percent of a utility's taxable power sales. Incentive payments to community solar projects cannot exceed 25 percent of the total allowable credit. The incentive amount may be uniformly reduced if requests for the incentive exceed the available funds.

The incentives apply to power generated as of July 1, 2005, and remain in effect through June 30, 2020.

**Washington Sales Tax Exemption**

A 100 percent Washington sales tax exemption for solar photovoltaic systems 10 kilowatts or less and greater than 1 kilowatt expires June 30, 2018 or January 1, 2020, depending on equipment type and size. There is a 75 percent exemption from tax for the sales of equipment used to generate electricity using fuel cells, wind, biomass energy, tidal or wave energy, geothermal, anaerobic digestion or landfill gas. The tax exemption applies to labor and services related to the installation of the equipment, as well as to the sale of equipment and machinery.

**Federal Tax Credit**

Established by the Energy Policy Act of 2005, the federal tax credit for residential energy property initially applied to solar-electric systems, solar water heating systems and fuel cells. The Energy Improvement and Extension Act of 2008 extended the tax credit to small wind-energy systems and geothermal heat pumps, effective January 1, 2008. Other key revisions included an eight-year extension of the credit to December 31, 2016; the ability to take the credit against the alternative minimum tax; and the removal of the $2,000 credit limit for solar-electric systems beginning in 2009. The credit was further enhanced in February 2009 by the American Recovery and Reinvestment Act of 2009, which removed the maximum credit amount for all eligible technologies (except fuel cells) placed in service after 2008.

A taxpayer may claim a credit of 30 percent of qualified expenditures for a system that serves a dwelling unit that is owned and used as a residence by the taxpayer. Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is at a new home, the "placed in service" date is the date of occupancy by the homeowner. Expenditures include labor costs for on-site preparation, assembly or original system installation,
and for piping or wiring to interconnect a system to the home. If the federal tax credit exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year. The excess credit may be carried forward until 2016, but it is unclear whether the unused tax credit can be carried forward after then. The maximum allowable credit, equipment requirements and other details vary by technology, as outlined below.

Taxpayers claim the credit by filling out Residential Energy Credit Form 5695 when completing their Federal income tax returns. There is no other application material, though documentation of project costs and proof of payment should be retained. Systems must be placed in service before December 31, 2016 in order to qualify for the 30 percent federal tax credit.

**Rooftop Solar**

The cost of rooftop solar has decreased dramatically over the past decade. In addition to the decreasing payback periods associated with rooftop solar, utility customers are interested in solar due to the following perceived environmental and societal benefits: reductions in carbon dioxide, oxides of nitrogen, sulfur dioxide and particulate matter, peak shaving, avoided distribution and transmission upgrades and a more diversified grid.

The industry is currently focused on attempting to decrease the non-hardware costs known as "soft costs" associated with rooftop solar that can make up as much as 60 percent of total installed costs. Soft costs include costs associated with permitting, installation, and interconnection. Exhibit 21 below shows a breakdown of historic and projected rooftop solar costs. SunShot’s target of $1.50/watt for rooftop solar is included in the exhibit.
The average rooftop solar installation in GHPUD’s service territory is approximately 5.9 kilowatts. Assuming a cost of $5 per watt, the total cost, before incentives, of the average rooftop solar system in GHPUD’s service territory is approximately $29,500. A federal tax credit of 30 percent reduces the total cost to near $20,500. Based on the time of installation, which impacts the number of years in which the customer qualifies for the Washington state Renewable Energy Production Incentive (discussed below), the payback period for a rooftop solar system is between 7 to 10 years.

**Residential Battery Systems**

SolarCity is currently offering battery storage systems to complement rooftop solar generation. However, including the batteries in a rooftop generating system nearly doubles the capital costs of the system. SolarCity is currently marketing battery storage in California. Their marketing suggests the primary benefits of a storage system are:

1) Backup generation in the case of a power outage
2) Reduce electric bills by shifting energy consumption from high priced periods to low-priced periods (assume the customer is served via time-of-use rates)
Given the current high cost of battery systems, it is likely that residential customers would only be interested in investing in battery systems in service territories in which power outages are frequent and costly and/or time-of-use rates allow customers to shift consumption from high to low priced periods.

**Smart Inverters**

An inverter converts the direct current electric output of a PV solar panel into a utility frequency alternating current that can be fed onto the electric grid or used by the electrical outlets in a home. Current inverter performance standards force inverters to disconnect at the first sign of a grid disturbance. In order to take advantage of the full capabilities of rooftop solar, especially when combined with battery storage system, so called “smart inverters” are needed.

Inverter standards need to be modified to allow inverters to a) stay connected to the grid during minor grid disturbances, b) change their output to assist the grid remain stable and c) assist the grid in maintaining the correct voltage and frequency. If a smart inverter detects voltage deviations exceeding 1 percent of normal, it will absorb additional reactive power. If line voltage drops below normal, as can occur when passing clouds suddenly reduce or eliminate rooftop solar generation, smart inverters can bolster line voltage by injecting reactive power. At night, when rooftop solar panels are not generating electricity, smart inverters can keep running on grid power which allows them to continue providing voltage regulating services to the grid.

In order for smart inverters to begin providing what are essentially distribution grid services inverter standards (mainly IEEE 1547) must be updated to allow smart inverters to enter the marketplace. The process of updating the standards has already started, but standards development is notoriously slow.

The added cost of smart inverters is low. Incorporating all the features of a smart inverter adds only $150 to the cost of a residential size inverter. Thanks to large subsidies Germany is the world leader in solar generation. However, most of the inverters included in the rooftop solar systems are not “smart inverters”. Germany, like other places such as Maui, has experienced grid instability due the large amount of solar generation on their system. They need a means of mitigating distribution grid voltage sags and surges that can occur when clouds pass over neighborhoods. Smart inverters can provide the mechanism to mitigate grid disturbances. In Germany they are currently retrofitting existing inverters with smart inverters. Retrofitting older technology inverters with smart inverters is costly. There is a push in the U.S. to avoid this unnecessary cost by installing smart inverters now in anticipation of future need.

California utilities are already pushing for all new rooftop solar sites to use smart inverters. The development of new inverter standards in California is the result of a state-specific standard, approved by the California Public Utilities Commission (“CPUC”) in December 2014. Revised standards will be mandatory in mid-2016. Smart inverters could be a fully integrated component of utilities’ distribution control systems within five years. Before that time the CPUC hopes to address whether inverter owners should be compensated for providing grid-regulation services.
**Smart Devices**

Solar production could be tied in more closely with the energy demands of each individual home. The Nest Learning Thermostat is an electronic, programmable, and self-learning Wi-Fi-enabled thermostat that optimizes the heating and cooling of homes and businesses to conserve energy. Nest’s thermostat gathers information about temperature and occupancy and could use that information to manage solar production. Through the “Works with Nest” program, some solar installers such as SolarCity are looking to coordinate energy production with all of the other devices that work with Nest’s smart thermostat. Nest claims that around 7,000 developers are working on products that can be integrated with its “Works with Nest” program, but has only announced a few dozen official integrations, including with energy-hungry appliances like Whirlpool washing machines.

If a cloud passes overhead, for instance, the SolarCity-Nest integration could automatically reduce energy use in a house, so the customer would have to rely less on energy from the grid. A home’s air conditioner or dish washer could automatically choose to run on solar power when solar production is at its peak during the middle of the day and hold off when the sun goes down.

**Community Solar**

Community solar projects are solar generating projects that accept capital from and provide credit for the output and tax benefits to individuals and groups of investors. Project technology, size, and financial structure can vary widely. The advantages of community solar include faster paybacks for consumers due to:

- up to double the state renewable energy production incentive ($1.08/kWh through June 2020 compared to $0.54/kWh for residential rooftop solar)
- home ownership is not required
- reduced installation costs due to economies of scale
- customers with poor solar potential at their residences can participate in a community project with greater solar potential

Community solar projects have been installed in many public utility service territories over the past two years including the city of Ellensburg, Seattle City Light, Clark Public Utilities, Mason PUD #3, Benton PUD and Inland Power & Light. Projects typically range in size from 10 kilowatts up to 75 kilowatts.

Contributors to projects typically receive direct credits on their electricity bills for the power produced by the systems. This “virtual net metering” arrangement produces a variety of efficiencies. The scale benefits that result from this financial model significantly reduce the cost of solar electricity. Just as importantly, because the utilities can organize the financial and technical details of projects as well as the installation and maintenance, participation does not
place an undue burden on the local citizens and businesses. In addition, businesses are able to leverage their participation in marketing and sustainability planning.

**Utility-Scale Battery Systems**

Utility-scale battery systems were discussed above. However, it is worth reiterating that battery systems could provide a feasible local resource option for GHPUD that could provide peak shaving that could reduce GHPUD’s risk exposure to the wholesale market. Batteries are one resource that would enable GHPUD to reduce its monthly system peak demands. Batteries could enable GHPUD to both reduce its monthly wholesale market power purchase costs and protect itself from significant increases in market prices during cold snaps and other high-priced market events.

Battery systems could also reduce congestion on the transmission and provide emergency power in the event of a transmission system event. GHPUD should consider whether or not there are particular feeders in its service territory that would be best suited to locate a battery system. Likely candidates include feeders that serve hospitals, feeders that are more likely to experience outages during severe weather events such as ice storms and feeders that serve isolated areas that are served by a single feeder.

**Neighborhood Batteries**

One approach to utilizing batteries to help GHPUD achieve the ideal load shape above would be to install medium sized batteries in neighborhoods in a manner similar to the way distribution transformers are installed in neighborhoods. For example, 25 kilovolt-amp distribution transformers are installed in neighborhoods and used to transform power to serve five or six homes. In this model multiple homes share one distribution transformer and benefit from load diversity (e.g. not all homes are running their hot water heaters, dishwashers, washing machines, clothes dryers, air conditioners, heat pumps and electric furnaces at the same time).

The same concept could be applied to batteries installed in neighborhoods to provide backup power to multiple homes with rooftop solar. Instead of each homeowner installing a battery to complement individual rooftop solar installations, a single, larger battery could be installed to complement rooftop solar generation at several homes. The cost of batteries increases as the size of the batteries decreases. Installing larger batteries to complement solar power generated at several homes would allow cost savings through economies of scale. As noted above, not all homes, even those in close proximity, have the same load profiles. Installing a single battery that charges and discharges based on the loads at several homes would result in more efficient operation of the battery by taking advantage of the diversity of loads at individual homes.

As discussed above, at this time the only way to make a battery storage system cost-effective is to secure grant money. The state’s Clean Energy Funds were set up to advance clean energy projects and technologies. Small scale battery projects located in neighborhoods would seem to be the type of projects that the Clean Energy Funds were meant to help facilitate.
Demand Response Units

In general, the flatter a utility’s load shape (i.e. the higher it’s load factor), the lower its power supply costs. GHPUD should consider investments, particularly in the residential and commercial sectors, that will result in higher load factors on a daily, monthly and seasonal basis. There are several tools that can be used to move GHPUD toward a flatter load profile including batteries, electric vehicle loads, demand response units and the efficient use of heat pumps.

Demand Response Units (DRU) are one of the tools that GHPUD could use to flatten its loads (i.e. increase its load factor). Several BPA customer utilities have participated in pilot programs with BPA in which DRUs were placed on hot water heaters.

GHPUD should consider gauging its customers’ interest in participating in DRU programs. If enough customers are interested, GHPUD should pursue the installation of DRUs to help GHPUD shape its loads and reduce power supply costs. A reduction in GHPUD’s monthly system peak loads can result in significant wholesale market purchase cost savings. GHPUD should consider providing incentives to customers that mirror the incentives the wholesale market is currently providing to GHPUD. High market prices during due to severe weather or other disruptions in the supply/demand curve that result in market price spikes inform utilities that there are savings to be had if utilities can decrease their peak loads (aka “peak shaving”). GHPUD could provide an incentive to its customers through a dollars-per kilowatt-hour credit or a fixed monthly or annual rebate in exchange for participation.

Potential candidates for inclusion in a demand response program in which DRUs are placed on appliances include space heating, water heating, commercial lighting and refrigerated warehouses. Exhibit 22 below shows the projected demand response program costs included in the 7th Power Plan.

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Customer Classes</td>
<td>$8.4 to $9.3</td>
<td>$5.7 to $6.3</td>
<td>$5.6 to $6.2</td>
</tr>
<tr>
<td>Residential Only</td>
<td>$9.1 to $13.5</td>
<td>$3.0 to $4.4</td>
<td>$2.9 to $4.3</td>
</tr>
</tbody>
</table>

Source: Northwest Power and Conservation Council’s Draft 7th Plan

There isn’t a liquid capacity market in the Northwest to measure demand response program costs against. Bilateral transactions for capacity products (call options) have been transacted in the northwest. The premium costs associated with call options is typically in the $2 to $3/kW-month range. The capacity market is more liquid in California because utilities are required to purchase capacity in order to meet resource adequacy requirements. Capacity contracts in California typically include capacity prices in the $2.5 to $4/kW-month range.
The capacity deemed to be available from wind and solar projects varies by month but is significantly less than the nameplate capacity of the projects in all months. For example, a 3 MW solar project may, on a planning basis, contribute no capacity during winter months but may contribute up to 2.5 MW in summer months. Market capacity prices in California are expected to increase in future years as more renewables come on-line, in order to meet the state’s renewable energy targets, and the system becomes more capacity constrained.

The northwest is also forecast to be capacity constrained during peak load periods. The system will become more constrained as more renewables (solar and wind) come on-line. If a capacity market develops in the northwest capacity prices will likely mirror those in California. As such, capacity prices in the $3.5 to $5/kW-month could be expected. By 2025 and beyond, demand response program costs may be equal to or below market capacity prices, in which case demand response programs would be cost-effective.

Programmable thermostats with two-way communications offer utilities an opportunity to reduce the consumption of residential customers that choose to participate during peak load or peak pricing events. In the winter utilities can send a signal to programmable thermostats to ramp down electric heat pump and electric forced air heating loads. In the summer a signal can be sent to reduced air conditioning load. Events could be called based on day-ahead load forecasts and day-ahead market price forecasts. A successful pilot program would likely want to limit the number of events that can be during each season and limit the duration of each load curtailment to two to four hours. Programmable thermostats can arrange to pre-heat or pre-cool a home prior to an event. For example, a programmable thermostat may pre-cool a home at 6 am and then turn the heat down over subsequent hours. Ideally, the home would retain the heat so that the customer would not notice the event. The cost of programmable thermostats varies from $250 to $300. Customers typically receive incentive payments or credits against their electric bills for participating.

**Biomass Energy Overview**

Biomass is made up mainly of the elements carbon and hydrogen. Several technologies can be employed to free the energy bound up in these chemical compounds. Biomass fuels include the following:

- Forest residue: log slash and forest thinning
- Paper mill residue: wood chips, shavings, sander dust and other wood waste
- Pulp chemical recovery: spent pulping liquor used in chemical pulping of wood
- Agricultural crop residues: obtained after harvesting cycle of commodity crops
- Energy crops: grown specifically for use as feedstocks in energy generation processes including hybrid poplar, hybrid willow and switchgrass
- Animal waste: combustible gas obtained by anaerobic decomposition of animal manure
- Municipal solid waste: organic component of municipal solid waste
Landfill gas/wastewater treatment: combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Four biomass energy technologies are discussed in detail below.

**Landfill Gas Projects**

Landfill gas consists mainly of methane and carbon dioxide and is produced when organic wastes in landfill sites decay. Landfill gas must be burned or flared in order to reduce the hazards associated with a large buildup of gas. Instead of being released directly into the atmosphere where it is a potent GHG, the methane can be used as fuel to power a turbine. For this reason, landfill gas generation is hailed for its potential reductions to GHG. It is estimated that methane has 21 times the greenhouse warming potential of carbon dioxide. Aside from global warming, landfill gas generation is also popular for reducing regional and local pollution. In addition, the PTC was expanded in the 2005 Energy Policy Act to include landfill gas generation. GHPUD should consider whether there is any potential for locating a landfill gas project at the Stafford Creek landfill.

**Anaerobic Digesters (Farm Manure)**

Animal waste management is a critical factor in protecting water quality. Anaerobic digestion is one method of handling manure that is likely to become more prevalent due to standards that require large (700 cows or more) dairy operations to obtain discharge permits. The permits require that an approved method of managing manure be included in dairies’ practices. The Environmental Protection Agency favors anaerobic digestion for managing manure. Manure is fed into a tank in which methanogen bacteria breakdown volatile solids into methane gas and carbon dioxide. The gas can be used by reciprocating engines to produce electricity. This method of generating power falls under the “biomass” categorization and qualifies as an eligible renewable resource under Washington’s RPS rules.

Animal wastes contain large quantities of nitrogen, phosphorous, potassium, and bacteria. If not properly managed, these wastes can enter surface water and cause eutrophication (excessive richness of nutrients in a lake or other body of water, frequently due to runoff from the land, which causes a dense growth of plant life and death of animal life from lack of oxygen).

The Department of Ecology assumes the primary enforcement role to ensure that agricultural operations do not degrade water quality. Farm owners are encouraged to work with the Natural Resources Conservation Service and the local Conservation District to develop and implement farm plans and Best Management Practices (“BMPs”) to protect water quality. Collecting and transporting manure to a generating facility would help farmers adhere to BMPs and reduce their risk of being fined by the Department of Ecology. This could ultimately reduce farmers’ overall compliance costs. A project would also protect water quality and provide local renewable generation.
Capital costs are estimated to be in the range of $3,200 to $3,700 per kilowatt installed for systems of 500 kilowatts and larger assuming generation would use reciprocating engines (per PacifiCorp’s 2015 Integrated Resource Plan page 118).

**Wastewater Treatment Plants**

Water resource recovery facilities, traditionally known as wastewater treatment plants, are uniquely positioned to be leaders in on-site renewable energy generation and energy conservation. Treatment facilities are very energy intensive. On-site cogeneration engines can be fueled by two fuels: biogas produced from the anaerobic digestion of wastewater sludge and biogas produced from the co-digestion of fats, oils and grease (“FOG”). The cogeneration also provides heat to the treatment plant. This method of generating power falls under the “biomass” categorization.

An initial investment in a FOG receiving and processing facility must be made in order to access a second source of biogas. However, a FOG station can also have profound operation and maintenance benefits. Diverting fats, oils and grease at their source (e.g. restaurants and food processors) before they get flushed into the wastewater collection system avoids significant collection system cleanout costs. The tipping fees FOG haulers pay to the county could result in a new revenue stream.

When combined with energy efficiency investments and on-site solar generation, the facilities can be managed to achieve net-zero energy demand. Net-zero energy consumption is the goal of a wastewater treatment plant in Gresham, Oregon. The Gresham facility is generating power using two 395-kilowatt co-generation engines fueled by biogas, including biogas from a FOG facility, and a 420-kilowatt solar system. The generation systems combined with energy efficiency investments will result in net-zero energy consumption for the facility. The facility is also generating RECs that will be sold to the local utility which will use them to comply with state RPS requirements. The Energy Trust of Oregon provided assistance and funds to lower the facility’s energy efficiency and reduce generation costs.

The potential for installing biogas-fueled generation at any of the waste water treatment facilities located in GHPUD’s service territory.

**Biomass-Woody Debris**

Direct combustion (the burning of material by direct heat) is the simplest method of capturing the stored chemical energy in biomass. Biomass generating projects fueled by woody debris typically burn forest waste. Cogeneration, sometimes referred to as combined heat and power, is the joint production of electricity and useful thermal or mechanical energy. The heat generated by burning woody debris is typically sold to a manufacturing process, a greenhouse or another industrial application that has a use for thermal energy. The electricity generated by a biomass-woody debris project is typically sold to the local utility.
Generating projects can be relatively small (e.g. 1 to 2 megawatts). GHPUD’s current BPA power contract allows “behind the meter” resources of up to 1 megawatt. “Behind-the-meter” resources essentially reduce utilities’ net loads on BPA.

Biomass generation fueled by woody-debris is dispatch-able and can be ramped up and down to follow daily load fluctuations. The ability to dispatch generation could allow GHPUD to reduce its peak loads and its wholesale power costs.

There are some concerns that woody biomass generation can result in increased greenhouse gas emissions. However, the EPA has stated that the impact is likely that there are minimal to no net atmospheric contributions of biogenic CO₂ emissions. Biomass generation could even reduce impacts compared to an alternate fate of disposal.

According to the 7th Power Plan the projected 20-year (2016-35) levelized cost of a biomass woody-debris project in the Northwest is $313 per megawatt-hour.

**Micro-Hydro**

Micro hydro is a type of hydroelectric power that typically produces from 5 to 100 kilowatts of electricity using the natural flow of water. The amount of generation at a particular project depends on the projected hydraulic head and flow of the project. The higher each of these are, the greater the potential capacity. Hydraulic head is the pressure measurement of water falling in a pipe expressed as a function of the vertical distance the water falls. A drop in elevation of at least two feet is typically required. Flow is the projected amount of water that falls in the project and is usually measured in gallons per minute, cubic feet per second, or liters per second.

The majority of micro-hydro projects are simply smaller versions of hydro projects that include intake structures, penstocks and powerhouses. Small generators that use the attraction water from fish ladders to turn small turbines are another example of micro-hydro projects.

A relatively new technology harnesses the energy in gravity-fed drinking water pipes. Lucid Energy has designed a hydroelectric system in which energy is generated as water flows through turbines integrated into water pipes. The two biggest benefits of utilizing existing drinking water systems are that there is no environmental impact and the projects would have high capacity factors since they will be generating energy 24 hours a day. Permitting a micro-hydro project could be a lengthy process due to the potential environmental impacts. Utilizing the existing infrastructure of the fish ladders of an existing dam or pipe-fed water systems would allow utilities to significantly simplify the permitting process and, in many cases, increase the capacity factor of the generation.
Resource Strategy

Resource plans evaluate potential future resources in areas of reliability, cost, risk and environmental impact. The preferred resource strategy is one that provides the best combination of cost and risk while meeting reliability and environmental needs. Resource planning considers demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs.

As discussed above utilities in Washington State with 25,000 customers or more are obligated to purchase eligible renewable energy on an annual basis in order to comply with the EIA. The EIA requires utilities to obtain increasing percentages of their total retail load from eligible renewable resources, such as solar and wind. Utilities can also purchase RECs in order to comply with the EIA. The renewable energy purchase requirements increased from 3 percent in 2012-15 to 9 percent in 2016-19 and will increase to 15 percent beginning in 2020.

Exhibit 23 below shows GHPUD’s projected renewable energy purchases compared to the EIA’s annual renewable energy purchase requirements. The eligible renewable resources shown below include GHPUD’s contract purchases with Sierra Pacific, CCAP and Nine Canyon. In addition, GHPUD’s eligible renewable energy purchases include an estimated amount of BPA Tier 1 RECs available to GHPUD to meet EIA requirements. The eligible BPA Tier 1 resources include power purchase agreements BPA entered into for a portion of the output of the Condon, Klondike and Stateline wind projects.
The “RPS Target” shown above is equal to 9 percent of GHPUD’s projected retail load in 2017-19 and 15 percent of projected retail load in 2020-2036. As shown above, GHPUD needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2022.

The steep decrease in GHPUD’s REC portfolio in 2022 is due to the expiration of GHPUD’s contract with Sierra Pacific in June 2022. GHPUD’s portfolio of RECs decreases sharply in 2031 as well due to the expiration of the CCAP contract in June 2030 and the expiration of the contract for Nine Canyon phase III output in July 2030.

In addition to the EIA, GHPUD may be required to comply with federal and/or state carbon policies in the near future. The result of whichever proposed carbon policy currently under consideration becomes law will be higher costs for fossil fuel-fired generating plants. Natural gas-fired plants and the wholesale market could be impacted depending on the carbon policy adopted by the state or federal government. As such, this section of the report will include the impact of a range of carbon costs on natural gas plant costs and wholesale market prices.

GHPUD wants to continue to encourage the use of energy efficiency/conservation in its service territory. In addition, GHPUD will continue to provide good customer service by assisting customers that are interested in producing renewable energy through net metered projects. Both energy efficiency and net metering reduce GHPUD’s future loads. As such, energy efficiency and net metering are the first resources deployed in that they reduce the need for other resources. In developing resource strategies, it is also important to consider the following:
- GHPUD purchases the majority of its power from BPA’s resources which are relatively low cost and low carbon emitting
- GHPUD does not want to decrease its reliability
- GHPUD wants stable power supply costs
- GHPUD must meet the EIA’s conservation and renewable energy requirements

This section focuses on the resource options that, based on current availability and projected costs, are the most likely candidates to serve GHPUD’s future loads and ensure EIA compliance. The resources examined include energy efficiency, wholesale market purchases, BPA Tier 1 power, natural gas-fired turbines, utility-scale solar, wind and small scale solar. Base case 20-year levelized costs of these resources were discussed above. However, the costs of all of the resources are based on assumptions regarding operating characteristics and cost components that, if altered, could result in higher or lower resource costs. As such, sensitivity analysis will be performed with respect to resource costs.

**BPA Power**

As discussed in the previous section, GHPUD currently purchases power from BPA as a “Slice/Block” customer under a 17-year contract that expires at the end of September 2028. Under the existing contract, power required to serve above-HWM load may be purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers.

Projected GHPUD loads include no load growth. Exhibit 24, below shows forecast annual loads compared to GHPUD’s contract and current rate period HWMs.
As shown above, based on projected GHPUD loads, GHPUD’s forecast loads are less than its current RHWM and contract HWM through 2028 (the end of the BPA contract period) and 2036 (the end of the IRP study period). With no projected above-HWM load, future resource acquisitions are not needed to serve load but are needed to comply with the EIA’s renewable energy purchase requirements. As such, three resource portfolios are considered in this section, all of which would achieve the goal of meeting the EIA’s renewable energy purchase requirements.

It is unknown whether the quantity of power and transmission currently provided by BPA under existing contracts will be available under new contracts that begin in October 2028. There is also uncertainty with respect to the price of BPA power in the future. BPA’s rates continue to increase with each two-year rate period. Thanks to low natural gas prices and depressed loads in the region BPA’s power rates are currently less than wholesale market prices. Whether or not this trend will continue is unknown. Based on current projections of wholesale market and natural gas market prices it could be argued that BPA’s rates will be above market for an extended period of time.

BPA currently pays over $200 million each year in residential exchange programs (REP) costs. These costs are based on a settlement of the REP benefits owed to Investor-Owned Utilities (IOUs). The settlement expires at the end of the current contract period. BPA has stated that the annual REP costs in future years could be as low as $0 or as high as $600 million. As such, there is much uncertainty regarding post-2028 BPA Tier 1 rates. Exhibit 25 below shows BPA’s
historic and base case projected rate increases. The projected BPA rates were provided by BPA in October 2015 as part of its “BPA Focus 2028” process.

Exhibit 25
Historic and Projected PF Tier 1 Rates and Rate Increases

As shown above in Exhibit 25 BPA’s rate increases have been 7.4 percent, 9.0 percent and 7.1 percent over the last 3 rate periods or six years. BPA is projecting smaller rate increases for the most part through 2030. However, the projected rate increases are still well above inflation and, based on base case forward wholesale market prices, will keep BPA rates above the market for many years to come.

Exhibit 26 below shows projected wholesale market prices compared to projected BPA rates. The projected BPA rates and low and high market prices shown in Exhibit 26 are based on projections provided by BPA as part of its “BPA Focus 2028” process. BPA provided low, base and high projections of BPA rates. BPA did not provide a base case market price forecast but rather provided a range of market prices that fall between the low and high market price forecasts shown below. The “base market” forecast prices shown below represents the base case market price forecast included in this study and matches up with the 20-year levelized wholesale market price shown above in Exhibit 20.
BPA’s projections extend out through the year 2030 or two years after the current power contracts expire in 2028. The average annual increase in the BPA base PF rates shown above is 1.9 percent. BPA’s PF rates are greater than the “base market” forecast through 2029. Projected market prices shown above are for flat power purchases while the BPA PF rates shown above are for load following and Slice/block contract purchases. As such, the comparison of projected BPA rates and wholesale market prices is not an apples-to-apples comparison.

The base case average BPA rate increase through 2030 is 4.3 percent. The average rate increase over the final ten years of the projections provided by BPA is 3.5 percent. The base case in this analysis assumes 3.5 percent rate increases every two years during the period 2031 through 2036. Given these assumptions, the base case 20-year levelized cost of BPA Tier 1 power is $47.2/MWh (delivered).

The low case rates were provided through 2030 and assumed low IOU REP benefit costs. Rate increases of 3 percent every rate period (every two years) were assumed in 2031 through 2036. Given these assumptions, the 20-year levelized cost of BPA Tier 1 power in the low case is $37.1/MWh (delivered).

The high case Tier 1 rates were provided through 2030 and assume high IOU REP benefit costs. Rate increases of 7 percent (every two years) were assumed in 2031 through 2036. Given these assumptions, the 20-year levelized cost of BPA Tier 1 power in the high case is $54.3/MWh (delivered).
Exhibit 26 illustrates that if BPA continues to increase rates as projected and if wholesale market prices continue to be relatively low, BPA may not be the lowest cost resource option for GHPUD in the future. Given the uncertainty with respect to BPA’s future rates and the amount of power that will be made available to BPA’s customer utilities under the post-2028 contracts, it is prudent that GHPUD consider its future non-federal resource options, particularly after September 2028.

**Non-Federal Resources**

As discussed in the Supply-Side Resources section, low and high wholesale market price forecasts were developed for this analysis based on current market trends. In the low market case, it was assumed that market prices escalate annually at an average rate of 2.5 percent, instead of the 4.9 percent average escalation rate included in the base case. In the high market case, it was assumed that market prices escalate annually at an average rate of 8.4 percent. The 20-year levelized cost of market purchases is $34/MWh in the low case and $60/MWh in the high case (delivered). The base case delivered market price forecast is $43/MWh (as shown in the Supply-Side Resources section of this report).

Exhibit 27 below summarizes the assumptions that were used to calculate low, base and high 20-year levelized costs for the other resources considered in this section. Small scale solar refers to solar up to 200 kW that is built in GHPUD’s service territory. The capacity factors are significantly less than those assumed for utility-scale solar projects which are assumed to be located in more geographically advantageous areas for solar generation. The capital costs are also significantly less due to economies of scale.

<table>
<thead>
<tr>
<th>Resource Operating Characteristics and Cost Assumptions</th>
<th>Natural Gas Turbine</th>
<th>Utility-Scale Solar</th>
<th>Wind</th>
<th>Small-Scale Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs (/kW)</td>
<td>$1,200 to $1,800</td>
<td>$2,600 to $3,400</td>
<td>$3,200 to $3,900</td>
<td>$2,200 to $2,800</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>95%</td>
<td>24% to 32%</td>
<td>29% to 35%</td>
<td>10.5% to 15%</td>
</tr>
<tr>
<td>Borrowing Rate</td>
<td>2% to 4%</td>
<td>2% to 4%</td>
<td>2% to 4%</td>
<td>2% to 4%</td>
</tr>
<tr>
<td>Year 1 O&amp;M Costs</td>
<td>$8 to $13/MWh</td>
<td>$16 to $32/MWh</td>
<td>$26 to $40/MWh</td>
<td>$55 to $75/MWh</td>
</tr>
<tr>
<td>Heat Rate (Btu/kWh)</td>
<td>8,000 to 9,200</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Gas Price Escalation</td>
<td>2.1% to 6.3%</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Year 1 Carbon Costs</td>
<td>$0 to $8/MWh</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>20-Year Levelized Cost</td>
<td>$35 to $75/MWh</td>
<td>$94 to $126/MWh</td>
<td>$110 to $139/MWh</td>
<td>$159 to 203/MWh</td>
</tr>
</tbody>
</table>

*Note: Year 1 O&M costs escalate by 1.5 percent annually. Year 1 carbon costs escalate by an average rate of 6 percent annually.*

The low case for the carbon costs shown above is based on no new carbon policies becoming law. The high case is based on an assumption that I-732 becomes law in Washington state. Projected
carbon costs are based on a base load natural gas fired CCCT with an emissions rate of 920 lbs/MWh running at a capacity factor of 95 percent.

Exhibit 27 above notes that the assumed annual natural gas price escalation rates vary from 2.1 percent in the low case to 6.3 percent in the high case. The resulting projected annual natural gas prices are shown below in Exhibit 28.

Exhibit 28
Range of Projected Natural Gas Prices ($/MMBtu)

As shown above, the average 2036 natural gas price approaches $8/MMBtu in the high case and is well below $4/MMBtu in the low case. The base case 2036 natural gas price is $5.3/MMBtu.

Exhibit 29 below shows the range of 20-year levelized costs for each resource option. The base case costs, which are discussed in the previous section of this report, are depicted by the red diamonds in Exhibit 29.
As shown above, while the market has a lower 20-year levelized cost than BPA Tier 1 power in the base case, the range of potential outcomes for market prices is greater than the range of potential outcomes for BPA Tier 1 power. The upper range of market prices includes carbon costs of $2.5/MWh in 2018, increasing to $7.5/MWh by 2036. Natural gas-fired turbine costs also have a fairly wide range of outcomes due to the exposure to carbon costs and natural gas price volatility.

**Displacing BPA Tier 1 Power**

As shown above in Exhibit 29, base case projected BPA Tier 1 rates are greater than base case projected wholesale market prices. Given this, it is prudent to consider the financial impacts of displacing a small amount of BPA Tier 1 power.

The retail rate impacts of displacing 1 aMW of BPA Tier 1 purchases with 1 aMW of the alternative resources were calculated. The risk of displacing BPA Tier 1 purchases with an alternative resource is that GHPUD’s rights to BPA Tier 1 power may be decremented in perpetuity. For example, the contract high water mark, or like allocation tool, in the next contract period may be decremented by the amount of non-federal resources used to meet load during the current contract period. While BPA Tier 1 rates are currently greater than market prices and are, under base case conditions, projected to be greater than future market prices, there are many factors that could cause future market prices to increase and, as shown above in Exhibit 29, projected market prices have greater variability than projected BPA Tier 1 rates.
Factors that could put upward pressure on future wholesale market prices include carbon costs and natural gas price spikes due to shifts in the current supply and demand paradigm for the natural gas industry. BPA Tier 1 rates are immune to potential cost adders associated with carbon emission restrictions. In addition, the impact of fluctuations in natural gas prices on BPA Tier 1 rates is muted by BPA’s ability to draw down reserves during periods of low surplus energy sales revenue. If a cap and trade program or carbon tax is implemented on a state or federal level the value of BPA Tier 1 power will increase due to the fact that it has no carbon emissions. Displacing Tier 1 power purchases with alternative resources due to current market conditions is not advised as it could have a long term effect on GHPUD’s ability to obtain its maximum allocation of Tier 1 power in the next contract period.

As shown below in Exhibit 30, under base case conditions, displacing 1 aMW of BPA Tier 1 power with 1 aMW of wholesale market power would result in no rate change over the 20-year study period. However, due to the variability of projected market prices the potential retail rate impacts of displacing 1 aMW of BPA Tier 1 power with market purchases varies from a 0.2 percent rate decrease to a 0.3 percent rate increase.

As noted above, displacing BPA Tier 1 power is not advised at this time due to the potential long-term impacts on GHPUD’s ability to purchase Tier 1 power in the long-term.

**Alternatives to Market Purchases**

The default resource for serving above-HWM load is market purchases. Exhibit 31 below shows the potential retail rate impacts of electing to serve 1 aMW of above-HWM load with a resource other than wholesale market purchases. As noted above GHPUD is not projected to have any
above-HWM load over the next 20 years. However, actual loads will differ from projections and as a Slice/Block customer GHPUD purchases power in the market when hourly load/resource imbalances require it to do so.

Exhibit 31
Retail Rate Impact of Purchasing 1 aMW of Alternative Resource instead of Market Power

As shown above, purchasing 1 aMW of output from a natural gas-fired turbine has lower potential retail rate impacts than purchasing 1 aMW of solar or wind power. The potential rate impacts of purchasing 1 aMW of output from a gas turbine vary from 0.2 to 0.5 percent.

While all of the resources shown above in Exhibit 31 would, based on the assumptions detailed above, result in greater power costs than relying on the market, there is value in having a more diversified resource portfolio. From a cost perspective different resources are exposed to different risks. Diversifying GHPUD’s resource portfolio would result in diversifying GHPUD’s risk exposure. There are many uncertainties with respect to future resource costs. For example, future resource costs are dependent on potential renewable portfolio standard legislation, natural gas market prices, the generating capability of the region’s hydro system, carbon taxes and/or a carbon cap and trade program. GHPUD should consider the value of a diverse resource portfolio.

Renewable Energy Compliance Portfolios

The cost of meeting the renewable energy requirements in the EIA were calculated for three scenarios or portfolios for the period 2022-2036. The 5-year period 2017-21 was excluded from the analysis because GHPUD has already committed to resources sufficient to meet the EIA’s renewable energy purchase requirements in 2017-21 (as shown in Exhibit 22 above).
Beginning in 2022 GHPUD has the following options for meeting EIA requirements:

- purchase the output of eligible renewable resources
- purchase a combination of eligible renewable resources and RECs
- purchase RECs only

Since GHPUD is in load/resource balance on an annual basis with just its BPA purchases (as shown in Exhibit 23 above), GHPUD would have surplus energy sales if additional resources were added to the portfolio. As such, GHPUD would end up purchasing renewable energy and re-selling it at lower market prices. In this case the cost of the renewable attributes used to comply with the EIA is the difference between the cost of the renewable energy purchases and market prices. The advantage of procuring the output from a renewable resource is that GHPUD would receive a steady supply of renewable energy at a known price and reduce its exposure to the REC market.

Three portfolios were developed for meeting the EIA’s renewable energy requirements. A sensitivity analysis is included to determine a range of costs associated with each portfolio. The three portfolios included in the analysis are discussed below.

**Portfolios for Complying with Renewable Energy Requirements**

**Portfolio #1: Purchase the Output of Wind and Utility Scale Solar Projects**

In Portfolio #1 a combination of wind and utility scale solar projects were selected. Utility scale solar has the lowest base case cost (as shown above in Exhibit 28) and the lowest potential retail rate impacts (as shown in Exhibits 29 and 30 above). However, given the amount of RECs required to comply with the EIA, a 54 MW solar project would be required (assuming a base case capacity factor of 28 percent). To date, no solar projects of that size have been proposed in the Northwest. Due to the lack of availability of solar projects with sufficient capacity, a wind project purchase was included in the portfolio.

Including two different renewable technologies also diversifies the portfolio’s risk exposure. For example, a year with poor wind generation may be offset to some extent by a better than average solar generation in the same year. The solar project was assumed to be a 5 MW project. Distributed generation, which is defined as an eligible renewable generation facility with a capacity of 5 MW or less, may be counted as double the facility’s generation. As such, the RECs associated with the 5 MW solar project included in portfolio #1 are assumed to be equal to twice the project’s projected generation. The remaining REC requirements are assumed to be provided by a wind project purchase. A wind project purchase of 23 MW with an assumed capacity factor of 32 percent is required to meet EIA requirements in 2024 through 2030. Both the Nine Canyon and CCAP Wind purchases expire in the summer of 2030. As such, the required wind project purchase is assumed to increase from 23 to 39 MW in 2031.

Exhibit 32 below shows how GHPUD would comply with the EIA’s renewable energy purchase requirements under portfolio #1. The EIA requirement is 15 percent beginning in 2020. Since no
load growth is projected, approximately 143,300 RECs would be required each year. It is assumed that GHPUD will receive 11,000 RECs each year from the renewable resources included in BPA’s Tier 1 resource stack. As such, 132,300 RECs are needed from existing and new renewable project purchases. Exhibit 32 also shows that RECs from previous years can be used to help meet compliance in 2022, 2023 and 2030. GHPUD has REC surpluses in 2017-2021. These surpluses are used in subsequent years and shown as “carry-over” in Exhibit 32. Due to the carry-over amounts new renewable resources are not needed until 2024.

Exhibit 32
Portfolio #1

Eligible Renewable Resources and EIA Renewable Energy Purchase Requirements (RECs)

Exhibit 33 shows GHPUD’s load/resource balance through 2036 with the new solar and wind projects added to the resource portfolio.
As shown above in Exhibit 33, the new solar and wind contracts are not needed to serve load and would result in surplus energy sales in addition to any surplus energy sales associated with surplus slice. As noted above GHPUD is short resources during some hours, particularly during cold winter mornings when hourly demand exceeds GHPUD’s resource stack. Adding wind and solar to GHPUD’s resource portfolio will not decrease GHPUD’s short positions during cold winter mornings. Wind and solar are not dispatchable and cannot be counted on to generate energy when it is most needed. Wind and solar projects in the region are usually generating no electricity during cold snaps. Due to the mild climate, GHPUD does not have a need for additional generation during summer peak load events.

**Portfolio #2: Purchase the Output of Wind and Utility Scale Solar Projects and RECs**

In portfolio #2 a combination of wind and utility scale solar projects are used to meet half of the renewable energy requirements beginning in 2024. REC purchases are used to meet the other half of the EIA’s renewable energy requirements.

The same 5 MW solar project that was included in portfolio #1 is included in portfolio #2. The RECs associated with the 5 MW solar project are again assumed to be equal to double the project’s projected generation. A wind project purchase of 9 MW with an assumed capacity factor of 32 percent is included in portfolio #2 in 2024 through 2030. Due to the expiration of both the Nine Canyon and CCAP Wind purchases in the summer of 2030 the wind project
purchase is increased from 9 to 17 MW in 2031. The remaining renewable energy requirements are provided by REC purchases.

Exhibit 34 below shows how GHPUD would comply with the EIA’s renewable energy purchase requirements under Portfolio #2. It is again assumed that GHPUD will receive 11,000 RECs each year from the renewable resources included in BPA’s Tier 1 resource stack. As such, 132,300 RECs are needed from existing and new renewable projects as well as REC purchases. REC carry over amounts (from surpluses in previous years) are used to help meet compliance in 2022 through 2024.

Exhibit 35 shows GHPUD’s load/resource balance through 2036 with the new solar and wind projects added to the resource portfolio.
As shown above in Exhibit 35, the new solar and wind contracts are not needed to serve load and would result in additional surplus energy sales.

**Portfolio #3: Purchase RECs Only**

In Portfolio #3 REC purchases are used to satisfy future EIA renewable energy requirements above the existing renewable purchases. Exhibit 36 below shows how GHPUD would comply with the EIA’s renewable energy purchase requirements under portfolio #3. As in portfolios #1 and #2 it is assumed that GHPUD will receive 11,000 RECs each year from the renewable resources included in BPA’s Tier 1 resource stack. As such, 132,300 RECs are needed from existing renewable project purchases and REC purchases. REC carry over amounts are used to help meet compliance in 2022 through 2024.
As shown above, no new resources are added in portfolio #3 as REC purchases are used to meet the EIA renewable energy targets in excess of existing renewable resources. In this portfolio, GHPUD has more exposure to REC price volatility.

Cost Comparisons

A range of costs were calculated for the three portfolios discussed above. The cost sensitivities are based on the following assumptions:

- **Resource Costs:** The range of resource costs shown above in Exhibit 29 were used in the cost calculations for each portfolio.

- **REC Prices:** REC prices are currently relatively low. However, the trend of low REC prices could change in the future as RPS requirements in Washington, Oregon, California and elsewhere ramp up. A base case 2017 REC price of $2/REC was assumed based on the current market prices for RECs. The base case assumes that REC prices escalate by 13 percent annually between 2017 and 2036. This results in a 2036 REC price of $20/REC. In the low case REC prices are assumed to escalate by 5 percent annually, resulting in a 2036 REC price of $7/REC. In the high case REC prices are assumed to start at $3/REC in 2017 and escalate by 18 percent annually, resulting in a 2036 REC price of $75/REC.
For each portfolio, Exhibit 37 shows the range of potential costs associated with acquiring new renewable resources and/or REC purchases required to meet the EIA’s renewable energy requirements. As discussed above, existing renewable resource contracts will allow GHPUD to meet EIA requirements through 2023 and new resource and/or REC purchase costs are not required until 2024. Since GHPUD either has surplus energy or is in load/resource balance without the new resources, the new resources acquired in portfolios #1 and #2 are not needed to serve load and are assumed to be re-sold at market prices. The net costs shown below include the revenue associated with re-selling the new renewable energy purchases in portfolios #1 and #2.

Net costs under base case pricing assumptions are depicted by the red diamonds in the above exhibit. The bottom of the blue box shows costs under the low sensitivity pricing assumptions while the top of the blue box shows costs under the high sensitivity pricing assumptions. As shown above portfolio #3, the “only purchase RECs” portfolio, is, by far, the lowest cost portfolio.

The low net cost cases in portfolios #1 and #2 include low solar and wind resource costs, high capacity factors and high market re-sale values. Likewise, the high cases in Portfolios #1 and #2 include high solar and wind resource costs, low capacity factors and low market re-sale value. In the most optimistic/low cases portfolio #2 has net costs of near $0. In these cases, the surplus energy from the new renewable contracts is re-sold based on the high market price assumptions, including the impact of carbon costs on market prices. In these cases, the market price for power is near $100/MWh in 2035-36 which is greater than the low case costs for solar projects (near $80/MWh). As such, portfolio #2 has the lowest potential cost of any of the scenarios. However, portfolio #2 has a much larger range of potential outcomes than portfolio #3 and a greater base case net cost.
Exhibit 38 below compares the portfolio costs on a levelized unit cost ($/REC) basis. Costs are incurred beginning in 2024. As such, the levelized costs are shown for the period 2024 through 2036.

GHPUD does not need more load-serving resources on a monthly and annual basis. There are peak periods, particularly in winter months, in which GHPUD is deficit and must rely on market purchases to meet hourly loads. From a planning perspective, the wind and solar resources included in Portfolios #1 and #2 would not reduce GHPUD’s need for market purchases during peak load events because the resources are not dispatchable and cannot be counted on to be generating electricity during peak load events. As such, portfolios #1 and #2 offer no advantages from a load/resource balance perspective and, as shown above, have greater base case net costs and much greater cost uncertainties. Relying on market purchases to meet short-term peak demand events comes with risk. However, GHPUD can evaluate the risks associated with short-term deficits and manage them without carrying the costs associated with the new renewable resources included in portfolios #1 and #2.

GHPUD’s peak hour deficits increase in 2023 after the expiration of the Frederickson PPA. GHPUD should closely monitor its capacity short positions going into each winter and work with its scheduling agent, The Energy Authority, to hedge risk as deemed appropriate by GHPUD’s risk oversight committee. In addition, GHPUD should monitor resource adequacy discussions in the region. If resource adequacy standards are required in the region the portfolios in subsequent IRPs will need to address those requirements.
Recommendations

The Northwest Power and Conservation Council’s 7th Power Plan concludes that conservation and demand response programs are the most cost effective future resources and can be relied on to meet future load growth and energy and capacity requirements. This is consistent with the recommendations of this study.

Many of the resources discussed in the “Supply-Side Resources” section of this report, such as pumped hydro, micro-hydro, batteries, grid management and tidal power, are many years away from implementation due to significant technological, permitting and cost hurdles. Some of the resources discussed above, such as solar, electric vehicles, conservation and demand-side management can be addressed in the near term.

Below are some basic observations that have been made throughout this report and should be used to help guide GHPUD’s future activities.

1) GHPUD’s lowest cost and lowest risk resources continue to be conservation/energy efficiency and BPA Tier 1 power purchases.

2) The expiration of the BPA power in September 2028 represents the biggest risk factor in GHPUD’s resource portfolio.

3) GHPUD’s current resource portfolio is low risk in the short- and mid-term. No load growth is anticipated and projected loads are expected to remain at current levels. Projected loads are less than GHPUD’s BPA contract HWM and current rate period HWM. No above-HWM load is projected over the study period. Since new resources are not needed to serve load, GHPUD should limit its consideration of future resource acquisitions to resources that will allow it to meet the EIA’s renewable energy purchase requirements.

4) In order to diversify its resource portfolio, increase its self-sustainability, decrease its dependence on BPA transmission to serve load and, potentially, decrease transmission costs, GHPUD should promote and incentivize local resource development.

Below are specific recommendations based on observations made throughout this report.

BPA Tier 1 Power

GHPUD should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently lower than BPA Tier 1 rates, and based on base case assumptions, are projected to be lower than future BPA Tier 1 rates, GHPUD should endeavor to retain its current allocation of BPA Tier 1 power as future wholesale market prices are exposed to price risks to which non-carbon emitting resources, such as BPA Tier 1 power, are not exposed.
Energy Efficiency

Energy Efficiency and, more specifically, the cost effective measures identified in the 2015 CPA, is the least expensive resource available to GHPUD. The CPA identified 7.62 aMW of cost effective conservation over the 20-year study period or, on average, 0.4 aMW per year. Implementing these measures will assure that GHPUD’s loads will remain flat (no load growth) which will, as a Slice/Block customer, reduce GHPUD’s market price risk exposure.

EIA Renewable Energy Purchase Requirements

Due to the expiration of existing contracts GHPUD is short renewable energy beginning in 2024. As such, any new resource acquisitions would need to be renewable. GHPUD’s BPA power contract expires in September 2028. Assuming GHPUD receives an allocation of BPA’s Tier 1 power that is similar in magnitude to its current allocation, GHPUD does not need new resources to serve load. If new resources were obtained GHPUD would, based on projected loads, have surplus energy which would be sold at market prices. This would expose GHPUD to market price risk on top of the resource output risk that comes with intermittent, non-dispatchable renewable resources. Intermittent resources would not reduce GHPUD’s exposure to market price and availability risk during peak demand events. The least cost and lowest risk strategy to complying with the EIA’s renewable energy purchase requirements is to purchase RECs in amounts sufficient to eliminate the projected renewable energy short positions.

Local Resources

In order to diversify its resource portfolio, increase its self-sustainability, decrease its dependence on BPA transmission to serve load and decrease transmission costs, GHPUD should promote local resource development and pursue state and federal grant money that would allow GHPUD to accelerate local resource development. Potential local resources include small scale solar, cogeneration at wastewater treatment plants, and battery storage systems that complement small scale solar systems and provide backup in the event of a transmission contingency. Purchasing the output of small scale local resources would most likely result in greater power costs and result in relatively small retail rate increases (less than 0.5 percent) for every 1 MW of installed capacity.

Demand Response Units

GHPUD should gauge its customers’ interest in participating in DRU programs. If enough customers are interested, GHPUD should pursue the installation of DRUs to help GHPUD reduce its peak demands and power supply costs. Reducing GHPUD’s monthly system peak loads would reduce GHPUD’s risk by reducing its exposure to market price and availability risk. GHPUD should consider providing incentives to customers that mirror the incentives the wholesale market is currently providing to GHPUD. The most likely candidates for demand response programs include space heating, water heating, commercial lighting and refrigerated warehouses.
Rooftop Solar

GHPUD should be ready to transition to installing smart inverters (after codes are updated) with rooftop solar installations so that GHPUD can be in a better position to operate a truly “smart” and efficient grid that seeks to flatten GHPUD’s load shape. This would ultimately result in lower distribution system and power supply costs. GHPUD currently has few (near 20) customers with rooftop solar installations. However, as discussed above, the cost of solar power is projected to decrease significantly over the next 10 years which, despite the relatively low capacity factor of rooftop solar in GHPUD’s service territory, will make rooftop solar more attractive to GHPUD’s customers. GHPUD should consider taking steps to prepare itself for growth in rooftop solar installations. Increased rooftop solar installations would have the benefit of reducing GHPUD’s load growth and reduce risk by reducing the utility’s exposure to wholesale market prices.

Pre-Pay Program

GHPUD should consider providing residential customers with a pre-pay option. Pre-pay programs increase customers’ awareness of how much energy they consume and allow customers to control their usage and costs. Pre-pay programs implemented at other electric utilities have been proven to result in energy savings.

Time-of-Use Rates

GHPUD should consider providing customers with optional time-of-use retail rates. TOU rates should encourage customers to shift loads to periods in which wholesale market prices are lowest (toward off-peak hours and away from peak demand hours). As a Slice/Block customer, TOU rates could provide another tool to reduce risk by reducing the utility’s exposure to wholesale market prices. GHPUD should further study the number of time periods and the definition of the time periods that could be included in future TOU rates.