INTEGRATED RESOURCE PLAN 2018

Resolution 8889 | August 14, 2018 | Exhibit A

Grant County
PUBLIC UTILITY DISTRICT

LETTER FROM THE WHOLESALE MARKETING AND SUPPLY

The next 10 years present a significant challenge for Grant PUD (District). Projected load growth that strains current resources, a changing wholesale energy market moving toward regionalization, and the push for reductions in carbon emissions presents a hazy planning horizon. The 2018 Integrated Resource Plan (IRP) is the District's road map for navigating this uncertain but exciting future.

Load Growth

The District, unlike most utilities in the Northwest, has seen a large amount of load growth over the past 10 years; an annual growth rate of 4% over this timeframe. The majority of this growth has been from an increase in a few large industrial customers. This load growth is forecasted to continue at a similar pace (3.4%) over the next 10 years, again with most of the growth projected to come from these few existing large industrial customers. This concentration of industrial load poses a significant amount of uncertainty in future resource needs as it could grow much faster or decrease almost overnight. In addition, the District has seen a significant amount of interest this past year from Evolving Industries such as crypto currency loads that compounds the uncertainty of future resource requirements.

Although the District has enough existing resources to meet expected load growth on an annual basis through the entire 10-year planning horizon, the District is forecasted to be seasonally capacity-deficit during late summer beginning in 2024 and winter capacity-deficit beginning in December 2028. The 2018 IRP address how the District plans to meet these needs.

New Wholesale Markets

Over the past two years, the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) has grown from two Northwest participants to seven, with an additional four utilities planning on joining within the next two years. This real-time energy imbalance market is in direct competition to the current real-time energy market (Mid-Columbia trading hub, Mid-C) the District relies on to meet its hourly energy needs. In addition, the CAISO this year presented plans for an Extended Day-Ahead Market (EDAM) to supplement the current real-time EIM. This proposed day-ahead market could further reduce liquidity at the Mid-C, making it more difficult for the District to meet its future energy needs with traditional tools. These developments, combined with the possible expansion of a Regional Transmission Organization (RTO) into the Northwest, make a regionalization of the Northwest wholesale markets more and more likely. We discuss these new markets and what impacts they may have on the District in the 2018 IRP.

Push for Carbon Free Energy

In the past few years, the District has seen a continued legislative effort to limit electricity generated by carbon-emitting sources in Washington State. This has been in primarily three forms; 1) an increased Renewable Portfolio Standard (RPS), 2) a tax on the emission of carbon, and 3) a cap on carbon emissions. Each one of these forms of carbon reduction changes the profile of the least-cost resource to meet District load and are discussed in detail in the 2018 IRP.

As you can see, the variability in loads, the regionalization of wholesale markets, and continuing efforts to limit carbon emissions in the region are creating complex uncertainties for Grant PUD. The role of Wholesale Marketing and Supply is to navigate all these uncertainties and provide the most value possible to our customers. This requires maximizing the resource assets of the District while finding the least-cost and lowest-risk options to meet customer load. The IRP is our roadmap to achieve these goals.

Rich Flanigan
Senior Manager of Wholesale
Marketing and Supply

RESOLUTION NO. 8889

A RESOLUTION AUTHORIZING AND APPROVING THE 2018 INTEGRATED RESOURCE PLAN (IRP)

Recitals

1. RCW Chapter 19.280.010 was enacted by the Washington State Legislature in 2006 to encourage the development of new safe, clean, and reliable energy resources to meet future demand in Washington for affordable and reliable electricity;

2. The State Legislature has found that it is essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources (conservation) they plan to use to meet their customers' electricity needs in both the short term and the long term;

3. RCW 19.28.030 requires that by September 1, 2018, Grant PUD adopt an Integrated Resources Plan which includes:

   (a) A range of forecasts, for at least the next ten years, of projected customer demand which takes into account econometric data and customer usage;

   (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

   (c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies;

   (d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

   (e) The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost and risk to the utility and its ratepayers; and

   (f) A short-term plan identifying the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

4. RCW 19.280.050 requires that Grant PUD's Commission encourage participation of its consumers in development of the Integrated Resources Plan and approve the plan after it has provided public notice and hearing which occurred on July 24, 2018;

5. Grant PUD's staff has prepared and submitted an Integrated Resources plan which meets the requirements of RCW Chapter 19.280.010 et seq., a copy of which is attached hereto as Exhibit A; and

6. Grant PUD's General Manager has reviewed the proposed Integrated Resources Plan and it complies with the requirements of RCW Chapter 19.280.010 et seq. and recommends its adoption by the Commission.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 2 of Grant County, Washington, that the attached Integrated Resources Plan is hereby approved and Grant PUD's General Manager is directed to file the plan with the Washington Department of Commerce.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 14th day of August, 2018.

Terry L. Brewer
President

ATTEST:

Secretary

Vice President

Commissioner

Commissioner

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1 | EXECUTIVE SUMMARY

The District has prepared this updated Integrated Resource Plan ("IRP"), which is a detailed load and resource analysis as part of its long-term planning process and pursuant to state requirements. This analysis indicates that during the next ten years, the District's need for physical capacity and energy beyond its current generation assets will be minimal. The District will acquire these resources through market purchases of firm generation as well as call options on firm capacity to cover peak demand. The District will also continue to invest in programs to achieve cost-effect conservation as determined by the 2017 Conservation Potential Assessment.

The District has enough qualified resources to meet the Washington State Renewable Portfolio Standard ("RPS") through 2024. Beginning in 2025, requirements resulting from the projected load growth and the higher RPS target (15% of retail load) will exceed the District's projected qualified resource generation. To cover the projected deficit, the District will purchase eligible Renewable Energy Certificates (RECs) from the market.

The loads and resources for the base year (2017) and two future years (2022 and 2027) are shown in Table 1-1 below. This table will be submitted to the Washington State Department of Commerce prior to the submittal deadline of September 1, 2018.

Table 1-1

	Base Year (actuals)			5 Year Estimate			10 Year Estimate		
Estimate Year	**2017**			**2022**			**2027**		
	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	771.70	825.84	572.72	908.00	987.00	738.00	1,003.00	1,101.00	834.00
Exports	1,421.09	1,202.44	709.68						
Resources									
Future Conservation/Efficiency						2.16			1.95
Demand Response									
Cogeneration									
Hydro	1,421.09	1,202.44	709.68	1,165.00	1,003.00	650.00	1,165.00	1,003.00	644.00
Wind			3.40			3.40			3.40
Other Renewables									
Thermal - Natural Gas						27.00	85.00	85.00	79.00
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts	997.70	1,125.84	751.72	303.00	430.00	302.00	307.00	413.00	302.00
BPA	10.17	4.54	5.64	9.00	8.00	5.00	9.00	8.00	5.00
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**2,428.96**	**2,332.82**	**1,470.44**	**1,477.00**	**1,441.00**	**989.56**	**1,566.00**	**1,509.00**	**1,035.35**
Load Resource Balance	**236.17**	**304.54**	**188.04**	**569.00**	**454.00**	**251.56**	**563.00**	**408.00**	**201.35**

Notes for Table:

1) Base year 2017 data is actual load and actual generation. Base year 2017 peak capability is the actual generation on the observed peak load hours for 2017.

2) Hydro values include Grant PUD rights in Wanapum, Priest Rapids, P.E.C, Quincy Chute and Wapato. Wanapum and Priest Generation is based on expected water. Grant PUD uses a 15% planning margin to cover various events such as a low water year, unplanned generation outages, extreme weather, unanticipated load growth, etc.

3) Conservation based on economic potential study performed in November 2017.

4) Physical loads and resources are covered through a resource and load exchange agreement with Shell Energy until 2020.

In preparing this IRP, the District identified a set of actions that it should include in the planning and analysis required for the 2020 IRP.

The District draws the following conclusions from the IRP analysis:

1. Based on the anticipated annual energy projections, the District has enough existing resources to meet expected load growth on an annual basis through the entire 10-year planning horizon.

2. As a result of the 15% planning margin, the District will use capacity call options to meet monthly deficits starting in 2020.

3. The District is forecasting to be seasonally capacity-deficit during late summer beginning in 2024 and winter capacity-deficit beginning in December 2028. To meet these seasonal deficiencies, the District will initially make Market Purchases starting in 2024. However, by July of 2027, the District expects to enter into a purchase power agreement for capacity from a generating resource. This decision is based upon the need to fill a large capacity requirement through the majority of the year and the assumption that this volume will be too large to fill through market trades.

4. The District will continue to meet its renewable portfolio obligations without acquiring new resources until 2025. At that time the District will acquire any expected RPS deficits with market purchases of eligible RECs.

5. The District load forecast contains significant uncertainty due to the relatively high percentage of industrial load. This load could be significantly higher or lower than forecast based on a number of factors, many of which are outside the District's control. The District has reviewed the potential risks associated with the load uncertainty, and will continue monitoring the load and expectations of this customer segment.

6. The District will need to stay abreast of changes in the utility industry affecting the District's planning processes.

IRP ACTION PLAN:

1. Monitor opportunities to procure low-cost, long-term generating resources (particularly resources that qualify for I-937 compliance), with an eye towards opportunities priced better than new-build costs. This includes the possible use of the Bonneville Power Administration (BPA) as a source of market purchases as well as preference customer status opportunities after 2028.

2. Continue to implement and achieve cost-effective conservation available within the county as indicated in the District's Conservation Potential Assessment.

3. Continue to enhance the capacity planning process and standards to ensure the District adequately plans to reliably meet both the energy and peaking needs of the District's electric system. The District's capacity planning process and standard should conform to the evolution in power planning for the Pacific Northwest. Therefore, the District should participate in and monitor regional forums related to resource planning.

4. Evaluate the relative value of the Shell Energy Exchange deal with a goal of determining whether to extend or replace the deal at the end of the five-year term. This effort should address areas where the arrangement could be improved for the benefit of the District and how the arrangement might work with the evolving Northwest energy markets.

5. Continue to refine and improve the retail energy load forecasts, with an emphasis on monitoring changes from the large industrial customers, given their ability to change the District load and resource balance. The District's ability to monitor and forecast resource requirements is being enhanced with the installation of the Advanced Metering Program.

6. Evaluate the opportunities presented by the expansion of the Northwest EIM and the possible growth of the California Independent System Operator into the Northwest. The District should work to identify the best strategy (from a cost, opportunity and risk basis) to interact with this evolving market.

7. Continue to participate in regional utility groups that monitor and influence legislation that could affect the District's ratepayers.

2 | OVERVIEW

The District has developed this Integrated Resource Plan ("IRP") to assess the long-term power supply condition of the District and as required in the Revised Code of Washington, Chapter 19.280. The District will use this IRP in conjunction with other long-term planning activities to meet the power needs of District customers at the lowest reasonable cost.

REQUIREMENTS FOR INTEGRATED RESOURCE PLANNING AND OBJECTIVES

The state of Washington has provided regulations for how public utility districts are to develop Integrated Resource Plans and describes the uses for the information provided in these plans. The District has used the requirements listed in these regulatory documents as objectives for this IRP.

Revised Code of Washington, Chapter 19.280

RCW 19.280 outlines the requirements of electric utility resource plans. The intent of this chapter of the Revised Code of Washington is to encourage the development of safe, clean, and reliable energy resources. Information from the integrated resource plans that are developed will be used to identify and develop: new energy generation; conservation and efficiency resources; methods, commercially available technologies, and facilities for integrated renewable resources, including addressing over-generation events; and related infrastructure to meet the state's electricity needs. The requirements listed in RCW 19.280 for large utility districts are as follows:

- Updated forecasts of projected customer demand
- An assessment of commercially available conservation and efficiency resources
- An assessment and comparison of renewable and nonrenewable generating technologies and resources
- An assessment of the District's ability to integrate renewable resources, and address over-generation events
- Utilization of demand forecasts and resource evaluations to describe the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs
- An Action Plan consistent with the IRP analysis and findings

Washington State Initiative measure number 937

I-937 was the Washington State clean energy initiative passed in 2006, which is now written in the Revised Code of Washington, Chapter 19.285. I-937 requires large utilities to obtain 15% of their electricity from renewable resources by 2020. Intermediary requirements include obtaining 3% of the utility's electricity from renewable resources by 2012, and 9% by 2016.

KEY RISKS ADDRESSED IN THE 10 YEAR IRP:

Many different risks and uncertainties have been considered while developing the District's Integrated Resource Plan (IRP). The risks discussed below are among those expected to be significant drivers of uncertainty for the District over the next decade and beyond. Anticipating changing costs and operating conditions is clearly a critical element of prudent utility management. Each risk is discussed in detail further in the body of this IRP.

Changing Power Market Risk

Significant change is already influencing the Western Electric Coordination Council (WECC) power markets. Over the next ten years, this change is expected to accelerate. The market of yesterday was fairly straightforward and familiar to many stakeholders. Most utilities were primarily trading bilaterally in organized markets such as the Mid-C trading hub. The District, being a pivotal member of the Mid-Columbia region, was well positioned to both buy and sell at this trading hub.

This historic marketing structure is rapidly changing with the advent of more regionally-oriented and much more organized market structures such as the Energy Imbalance Market (EIM) and Two-Settlement RTO/ISO-managed markets evolving in our area. Fortunately, this evolution is not new or unique to our region. Markets throughout the United States have experienced these transformations since the mid-1990's. These transformations are predictable and anticipated to occur in the Pacific Northwest over the next ten years.

The District must be mindful of these evolving markets when it produces its Integrated Resource Plan. This is especially true as the number of utilities making the transition from the old market structure to the new one grows. Some of the District's key neighbors who have joined the EIM include Portland General Electric, Puget Sound Energy, Pacificorp, and Idaho Power. It's only a matter of time before those who are members of such markets become economically distinct from those who have not made the transition.

Environmental/Legislative Risk

The District faces significant uncertainty regarding the magnitude and cost of carbon-related legislative action. This may manifest itself in a direct price levied against those who are responsible for releasing carbon into Washington's atmosphere. Increased costs may also be created by an increase in the Renewable Portfolio Standards (RPS) creating the need for new investments in RPS-qualifying capacity and transmission. Many of the specific details of this extensive risk are thoroughly discussed in the body of this IRP. The District will continue to monitor these developments.

Load Risk

More than a third of the District's demand (or load) is attributable to its industrial customers. These customers face the same kind of financial constraints and efficiency needs that all businesses face – including Grant County PUD. Consequently, they tend to be very sensitive to the price of their critical inputs which often include the energy we supply. Specific District customers such as data centers, chemical producers, and agriculture processors are particularly sensitive to rates. Competitive rates can attract significant growth in industrial load over a very short time period. This makes this customer class the highest load risk we face. The District's 15% planning margin is expected to safeguard against unanticipated changes in load.

Additionally, as many Grant County residents have experienced, temperatures are highly variable. Extremely hot summers can easily follow extremely cold winters. Such temperature fluctuations can cause unexpected high loads due to demand for cooling or heating. The District's 15% planning margin is expected to manage these extremes as well.

Water Risk (and operational risk)

The District's hydro project's ability to produce power is highly dependent upon the quantity of water available to it in any particular year. While the entire Columbia River benefits from the extensive water regulation provided by US and Canadian entities, the District is exposed to significant annual and monthly variability in the amount of power it expects to have to serve its load. In the short-run, the District's Integrated Resource Plan relies upon its ability to store water over short periods of time in its project's reservoirs to cover extreme intra-day peaks and satisfy its desire to maintain a 5% Loss of Load Probability(LOLP)[1] Water quantity risk expected to be experienced over days, weeks, and months is managed by the District's 15% power planning margin. This margin is expected to cover drier years such as occurred in 2001 (which, incidentally, is expected to occur once every twenty years). The District's current hedging strategy of selling slices of the Priest Rapids Project resource with quantity-certain physical power buyback provisions are helpful in managing annual variability.

Fuel Risk

The District anticipates using thermal generation to meet much of its future needs because this is the supply resource that is expected to be the lowest cost in the largest number of scenarios being considered. Consequently, this exposes the District to the variability in the cost of natural gas. Fortunately, the demand for natural gas has not been stronger than our national supply for many years and is not expected to do so for many years to come. This risk can be managed with standard hedging techniques.

[1] A loss of load occurs whenever the system load exceeds the available generating capacity. The overall probability that there will be a shortage of power (loss of load) is called the Loss of Load Probability or LOLP. It is usually expressed in terms of days per year, hours per day or as a percentage of time.

Transmission Risk

Market and environmental changes are also driving a significant change in how the WECC transmission grid is expected to operate. Investment in renewable generation like wind and solar capacity will require significant investments in transmission to reduce the inevitable congestion created by the power delivered by these new resources. This effect has been seen in many regional RTOs/ISOs such as the Midwest Independent System Operator, the Southwest Power Pool, and the Electric Reliability Council of Texas. Central and Eastern Washington are being considered by many renewable developers as prime sites for additional renewable generation development. The District is currently evaluating several requests for large solar project interconnections to our system.

NORTHWEST POWER AND CONSERVATION COUNCIL SEVENTH POWER PLAN

The District has based many of its assumptions on the Northwest Power and Conservation Council ("NWPCC") Seventh Power Plan. The NWPCC prepares regular assessments of the regional power supply situation and projects an aggregated load resource balance into the future. This assessment includes detailed modeling of the Pacific Northwest resource mix and also includes detailed information regarding the cost of different supply-side resource technologies as well as cost-effective conservation.

In February of 2016, the Council published their Seventh Power Plan. Regional utility and other energy industry staff assisted the NWPCC in the preparation of the plan and Grant PUD staff have reviewed the findings. Of interest to this IRP planning process are the following information and findings contained in the Seventh Power Plan:

- Eight regional coal plants are slated for retirement between 2020 and 2028. These include Centralia units 1 and 2, Boardman, Valmy units 1 and 2, Colstrip units 1 and 2 and Jim Bridger 1. These retirements total 4,070 MW of capacity. In addition, a requirement of Hydro One's purchase of Avista is the accelerated depreciation on units 3 and 4 of Coalstrip from 2036 to 2027. These early retirements were facilitated by the desire of the utility customers to reduce carbon emissions.

- The NWPCC projects resource development through 2035 to be primarily additional efficiency measures supplemented primarily with natural gas generation being added to replace retired coal units.

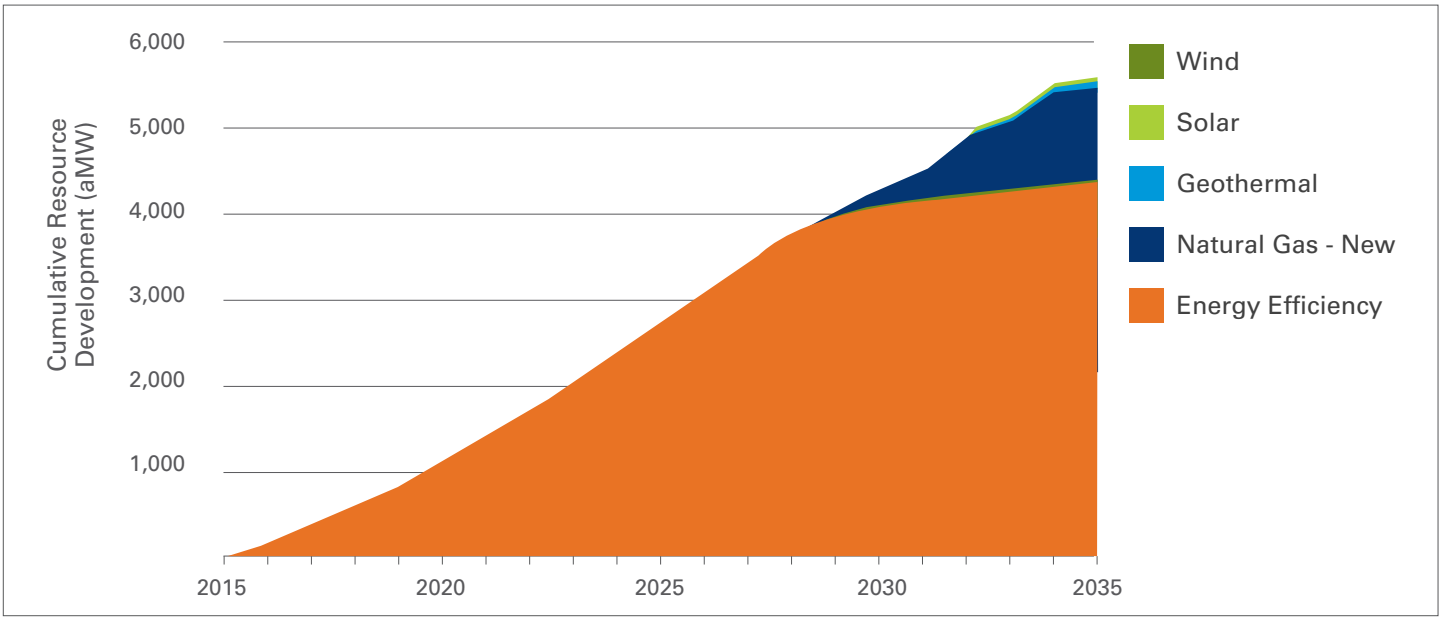
- Demand response was considered, and the NWPCC found 600 MW of demand response programs to be cost-effective in 70% of the futures modeled.

- The plan projected only a modest amount of additional renewable resources to meet regional RPS requirements. The amount added was 250-400 MW installed capacity or 100-150 aMW of energy production.

While the findings of the Seventh Power Plan cannot necessarily be translated directly to Grant PUD, the Plan's identification of an approach for meeting future loads in the region is rather emphatic, with a clear high degree of reliance on conservation and efficiency measures as demonstrated by this chart (Graph 2-1) from the plan[1]:

[1] NWPCC Seventh Power Plan page 1-2.

Graph 2-1



REGIONAL RESOURCE ADEQUACY

The Pacific Northwest has historically been one of the least energy-constrained regions of the electric grid. This was due to the predominant use of hydro-electric generating resources, which produced a system rich in generating capacity and flexibility, but subject to energy shortages in years with low precipitation and snowpack. As the region has added increasing amounts of thermal and renewable resources and as the hydro-electric system flexibility has declined, the region finds itself transitioning into a peak-constrained system. The industry has been working to better define appropriate resource adequacy standards during this time of transition and to better understand how individual utilities should plan and apply standards. The NWPCC computed the Loss of Load Probability (LOLP) for the region using their detailed adequacy model and determined both energy and capacity needs to maintain an LOLP of less than 5% for the region. Using this metric, and modeling tool, the NWPCC in their Seventh Power Plan determined that only a modest amount of energy resources will be needed through 2035 and that peaking or baseload resources are needed starting in 2021 when Boardman and Centralia 1 are slated for retirement. The District is also using a 5% LOLP planning metric and has enough capacity to meet its summer and winter peaks over the planning horizon. The Priest Rapids Project (Wanapum Dam and Priest Rapids Dam) possesses the flexibility necessary to make this possible through storing water to be used during peak requirements.

The District is also implementing a 15% power planning margin as it models the District's specific resource requirements. This planning margin is designed to cover most prolonged resource outages, variations in weather, water for generation, economics, and general load growth.

EMERGING CARBON AND ENERGY POLICIES

Federal and State policymakers and agencies continue to propose new laws and rules related to energy policy and/or reducing carbon emissions, which could have significant impact on electric utilities' operations and rates. Increasingly, policies to reduce carbon emissions and/or mandate technology-specific renewable energy development are the focus and priority of policymakers in the Washington State legislature. While Grant PUD does not own any carbon producing power plants, it can be heavily impacted by these emerging policies due to its market power purchases and the electricity industry's reliance on some carbon-emitting power generation for system reliability. The following is a summary of recent Federal and State regulatory activity related to the ongoing advancement of carbon and energy policy. The District has evaluated the likelihood of these regulatory activities affecting the resources available within our region and has modeled the most probable scenarios (See Section 9).

Background and Influence of Renewable Portfolio Standards and GHG Reduction Goals

In November 2007, Washington voters approved Initiative I-937 which established conservation and Renewable Energy Portfolio Standards (RPS) for large utilities (serving 25,000 or more customers) in Washington State. Under the RPS, only "incremental hydro," a small portion of the total of renewable hydroelectric power in Washington State, qualifies as a renewable energy resource along with wind, solar and a few other resources. The RPS obligates large utilities to acquire qualified renewable resources, up to 9% of their retail load, beginning in 2016 and 15% by 2020.

In 2008, the Washington legislature established statewide greenhouse gas (GHG) emission reduction targets. RCW 70.235.020 identifies the goals are to reduce emissions to 1990 levels by 2020, 25% below 1990 levels by 2035 and 50% below 1990 levels by 2050. Oregon and Washington are currently exploring additional commitments to reduce their state carbon emissions to 80% below 1990 levels by 2050. Also, both Oregon and Washington have taken steps to arrange for the closure of coal plants in their state by 2025.

In 2016, Oregon voters approved a renewable portfolio standard for Investor Owned Utilities of 50% by 2040. Similarly, California also requires utilities to purchase 50% of renewables to meet retail load by 2030. Similar to Oregon and California legislation, advocates for renewable energy in Washington State have proposed to significantly increase the RPS goals after 2020.

The High Cost of RPS Policies

While mandated RPS have allowed certain technologies to be developed, the timing of the build out has not been tied to load growth. In Washington State and the Pacific Northwest in general, the RPS policies have resulted in unintended consequences including: 1) energy oversupply by building renewables ahead of need; 2) forced curtailment of energy resources; 3) negative wholesale energy prices primarily during the springtime; and 4) reduced capacity to meet peak load in the winter months during low water years.

The E3 Study

Because of the unintended consequences associated with RPS policies and the competing policy to reduce greenhouse gases, the Public Generating Pool

(PGP) commissioned Environmental Engineering Economics, Inc. (E3) to study the cost-effectiveness of different policies to achieve a desired GHG reduction goal of 80% below 1990 levels by 2050. Based on their study, E3 found that technology neutral policies that target carbon directly, like a carbon tax or a cap-and-trade program, achieve the most carbon emission reductions, and at a lower cost, than an increased RPS. The E3 model found that the most cost-effective, near-term carbon reduction options include maintaining existing carbon-free resources, energy efficiency investments and transition from coal to the least-cost combination of renewable resource, natural gas and other technologies to meet energy and capacity needs. (See Appendix 3)

Comparison to a 50% RPS Policy

Importantly, both the Northwest Power Planning Council and the E3 study found that a regional (Washington, Oregon, Northern Idaho, and Western Montana) 50% RPS, similar to HB 2402 proposed in 2018, would result in the highest monthly electric bills for consumers at an annual cost of over $2.2 billion dollars. In comparison, a carbon price applied across the entire Western electric market to achieve a desired GHG reduction goal of 80% below 1990 levels by 2050 would result in the lowest monthly electric bills and cost approximately $1 billion annually over the cost of existing regulations or status quo. To emphasize the point, the E3 study found that a 50% RPS would achieve only about 50% of the desired emission reduction goal and would cost twice as much.

LOWER COST OPTIONS TO REDUCE GHGs

The following are examples of proposed greenhouse gas reduction policies that could be implemented at a lower cost than an expanded RPS policy. However, each of these policies were not implemented due to changing political support, legal challenges or both.

Federal Clean Power Plan

In August 2015, the Environmental Protection Agency (EPA) proposed the Clean Power Plan (CPP) to reduce carbon emissions by 32% relative to 2005 levels by requiring carbon emission reductions by state. On February 9, 2016, the Supreme Court stayed the regulations pending judgment by a lower court. In October of 2017, the EPA, under the Trump Administration, began taking steps to repeal the CPP.

Washington's Clean Air Rule

On September 15, 2016, Ecology adopted Chapter 173-442 WAC – Clean Air Rule - to cap and reduce GHG emissions from significant in-state stationary sources, petroleum product producers, importers and distributors, and natural gas distributors operating within Washington. Initially, the Clean Air Rule (CAR) would have required businesses that emitted more than 100,000 metric tons of carbon dioxide (CO2) and CO2 equivalents to reduce their emissions by an average of 1.7 percent annually. Reductions could be achieved through on-site reductions of emissions, the implementation of certain offset programs (such as commuter reduction plans, etc.), or the purchase of offsets / allowances from external sources or markets. In response to a lawsuit challenging the CAR, the Thurston County Superior Court ruled in March 2018 that Ecology's authority to regulate under the state's Clean Air Act does not extend to those companies who sell products, only to those who directly emit carbon. Although this ruling suspended implementation of the CAR, had the court decision gone the other way, neither the District's non-emitting generation resources nor its imported purchases would have been regulated. Consequently, District staff forecast a modest increase in the cost of market power under the CAR. The Washington State Department of Ecology has appealed this decision to the State Supreme Court.

Washington State Initiative 732 (2016)

In November of 2016, Initiative 732 was on the ballot to establish a $15/ ton tax on fossil fuels and electricity rising to $100 over time. Although claimed to be tax neutral via reductions in the sales and B & O taxes, the initiative was voted down (40.7% yes to 59.3% no).

2018 Governor's Carbon Tax Bill

During the 2018 legislative session, Governor Jay Inslee sponsored Senate Bill 6203. SB 6203 passed out of committee, but lacked sufficient support to pass the Senate. The bill proposed a tax of $12 per metric ton (MT) of CO2 beginning July of 2019 and would rise by $1.80 annually starting in July 2021 until it reached $30 per ton, when it would be capped. Numerous businesses deemed to be sensitive to the tax would have been exempted. This bill contained a provision for utilities to retain and reinvest tax revenues in their local areas under an approved plan that would have reduced GHGs through developing renewable generation assets, conservation, electric vehicle (EV) fleet conversion and other approved investments.

2018 - Initiative 1631

This initiative was filed in March of 2018, by a coalition including the Alliance for Jobs and Clean Energy, The Nature Conservancy, and a number of Washington's Tribes. The initiative obtained the 259,000 signatures necessary to get on the November 2018 ballot. The initiative calls for a $15 per ton fee on carbon in 2020, then rises $2/ton plus inflation annually until 2035 at which point it is projected to be $55/ton. Like

the Governor's bill, I–1631 provides an opportunity to retain and reinvest the fees into GHG reduction programs pursuant to an approved clean energy investment plan. An analysis of the cost of I-1631 by E3 reveals that in 2050, the retail rate impact may be 7% compared to a 5% increase estimated under a more efficiently designed policy to achieve an 80% reduction below the 1990 GHG levels. Should the initiative fail or pass this fall, it isn't known whether the legislature will pursue additional or alternative carbon policies in 2019.

HIGHER-COST CLEAN ENERGY POLICIES

100% Clean Energy Policies

In 2018, lawmakers also considered different concepts of a 100% Clean Energy standard. (See HB 2995 and SB 6253, (2018)). Key findings from the E3 study include:

- Costs increase exponentially when reducing GHGs above the 80 % reduction from the 1990 standard. In 2050, the costs to meet the 80% reduction (21 million MTs) is approximately $1.1.billion per year while the cost to achieve a 100% clean scenario (28 million MT) is $6.5 billion per year.
- 95% GHG reductions below 1990 levels is achievable with current technology but requires 6,000 MW of new natural gas to replace existing coal generation.
- Limits on thermal resources under the 95% or 100% reduction scenarios have not proven to be reliable. BPA also stated there is insufficient analysis available to have a fully informed perspective on the potential impacts of such a policy to the regional electricity grid.
- Research shows the carbon tax under a 100% clean scenario in 2018 could be greater than $700/ton when revenues are not reinvested. This is 23 times higher than Governor Inslee's bill.
- HB 2995 and SB 6253 also did not fully recognize hydro or nuclear power as a carbon free energy resource.
- The 100% clean energy policy exceeds the GHG reduction goal of 50% below 1990 levels found in RCW 70.235.020 and the desired goal of 80% reduction below the 1990 levels.

Carbon Price and 100% Clean Energy

Environmental groups have advocated for a 100% clean energy policy in addition to a price on carbon. This is the highest cost option of the policies considered. In 2050, 100% clean energy and a carbon tax results in a rate impact of 35%, construction of 45,000 MW of new renewables and 35% curtailment of those renewables when the added capacity isn't needed. This results in an estimated cost of $18.4 billion annually to the Core Northwest (E3 Study).

GRANT PUD'S PROACTIVE INTERIM ACTIVITY

Effective Carbon Reduction

Grant PUD is developing a discussion draft legislative proposal with the idea of proposing an alternative policy that could potentially be supported by Grant PUD and a consortium of utilities and key stakeholders. The discussion draft would:

- Achieve a carbon reduction goal (i.e. Outcome-based goal with flexibility and local control over decisions to achieve the goal in a least-cost manner);
- Establish one unified carbon/energy policy in WA;
- Be technology neutral;
- Provide for a reliable grid;
- Provide mitigation for highly impacted entities;
- Incent electrification of transportation, industry and business sectors;
- Allow regional coordination.
- Provide for 2-3 year rulemaking to allow adequate time to get implementation details correct.
- Preempts changes/increases to I-937.
- Exempt Ag transportation for hauling crops to market.

Grant PUD will continue to actively engage with various stakeholders, industry groups and policymakers in the development of this discussion draft bill.

3 | WHOLESALE ENERGY MARKET

Grant PUD provides reliable power to a diverse set of residential, commercial and industrial consumers. To accomplish this, it needs to use a combination of its own generation capacity and possibly contracts for power from other sources. Flexibility is important as customers' needs change from year to year, month to month, day to day, and even moment to moment. Grant PUD does this basically on its own through wholesale energy markets. This is done through portfolio planning down to the hourly level, and by making dynamic adjustments as necessary to cover its load obligations on a moment to moment basis. A robust and liquid wholesale energy market is vital to meeting the District's energy needs. Grant PUD currently operates within the Western Electric Coordinating Council (WECC). Within the WECC, there are numerous bilateral trading hubs such as the Mid-Columbia (Mid-C), SP15, NP15, COB, and Palo Verde. Grant PUD currently relies heavily on these markets with specific concentration at the Mid-C.

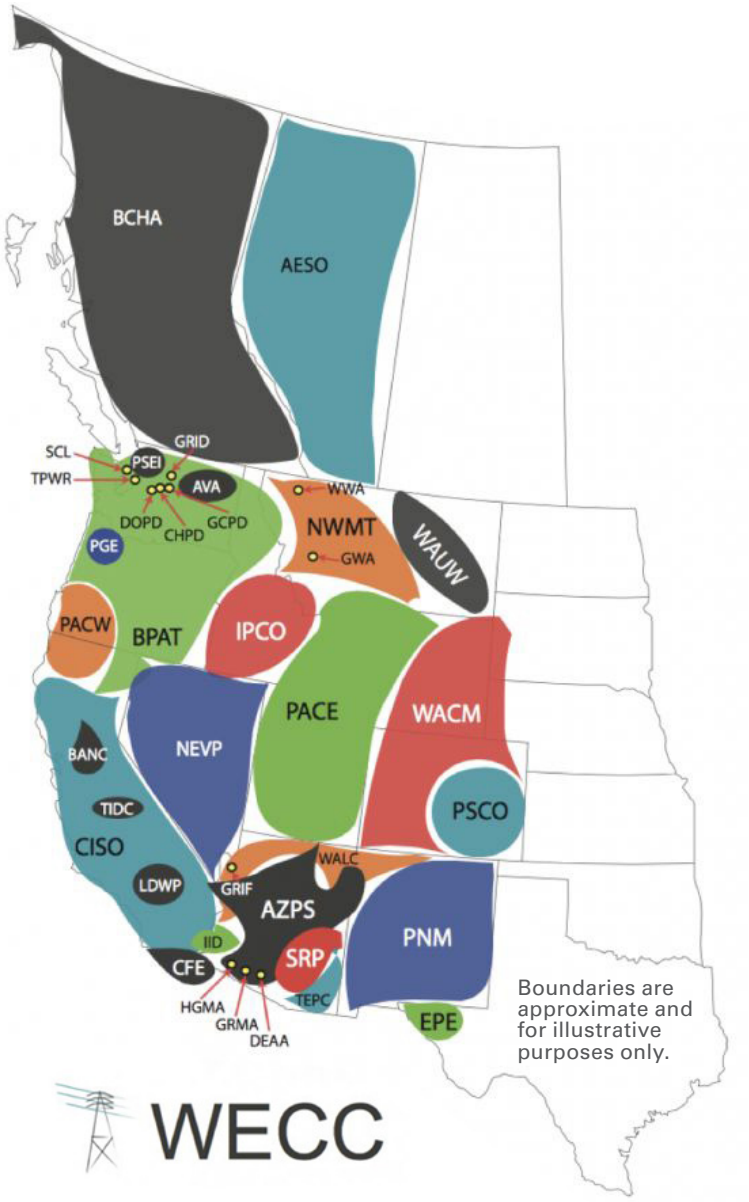
There are two other organized markets operating in WECC that Grant PUD does not currently participate in: the California Independent Operator (CAISO) and the CAISO Energy Imbalance Market (EIM). Over the past year, the WECC has also seen developments in the formation of other markets. These include the Southwest Power Pool, Peak/PJM, and an additional feature to the EIM called the Enhanced Day-Ahead Market (EDAM). Grant PUD is monitoring these developments. At this time, the District does not believe participation in these markets would provide net benefits to Grant customers, in part due to requisite investments in accounting, metering, and personnel. This could change in the near future. The District is preparing for the opportunities and risks these evolving markets can produce.

WECC

In the western electrical interconnection of the United States, there are dozens of individual utilities and operating companies that are linked together by transmission lines, collectively called the Western Interconnection (See Figure 3-1). The transmission lines allow these utilities to buy and sell power between themselves via several "markets" effectively overlaid upon the grid. Examples of these include the energy, ancillary, and green-attribute markets which separate markets into their primary product offerings. Additionally, there are real-time, day-ahead, and long-term markets which effectively separate markets by the relevant time periods under which power is being traded. And finally, there are energy imbalance markets, two-settlement markets, and bilateral markets which are effectively separated by the contractual terms and market organizational structures by which transactions occur.

In all cases, these markets are unified by their ability to facilitate the buying and selling of specific amounts of electricity and its attributes for specific periods of time in an organized manner. The benefit of using such markets is that they allow for price discovery as buyers and sellers of power meet to transact clearly defined products for defined time periods at the lowest possible transaction price. As one market evolves, it is often at the detriment to existing markets. This may prove to be the case in our region. The evolution of a new market may cause the District's previous market participation to become less economically viable. However, the District is aware that the costs of joining a specific market may be higher than the achievable benefits. It is also aware that joining such markets may still be the least-cost alternative. The District plans to study the relative cost/benefit of joining any of the developing markets.

Figure 3-1



Western Interconnection Balancing Authorities (38)

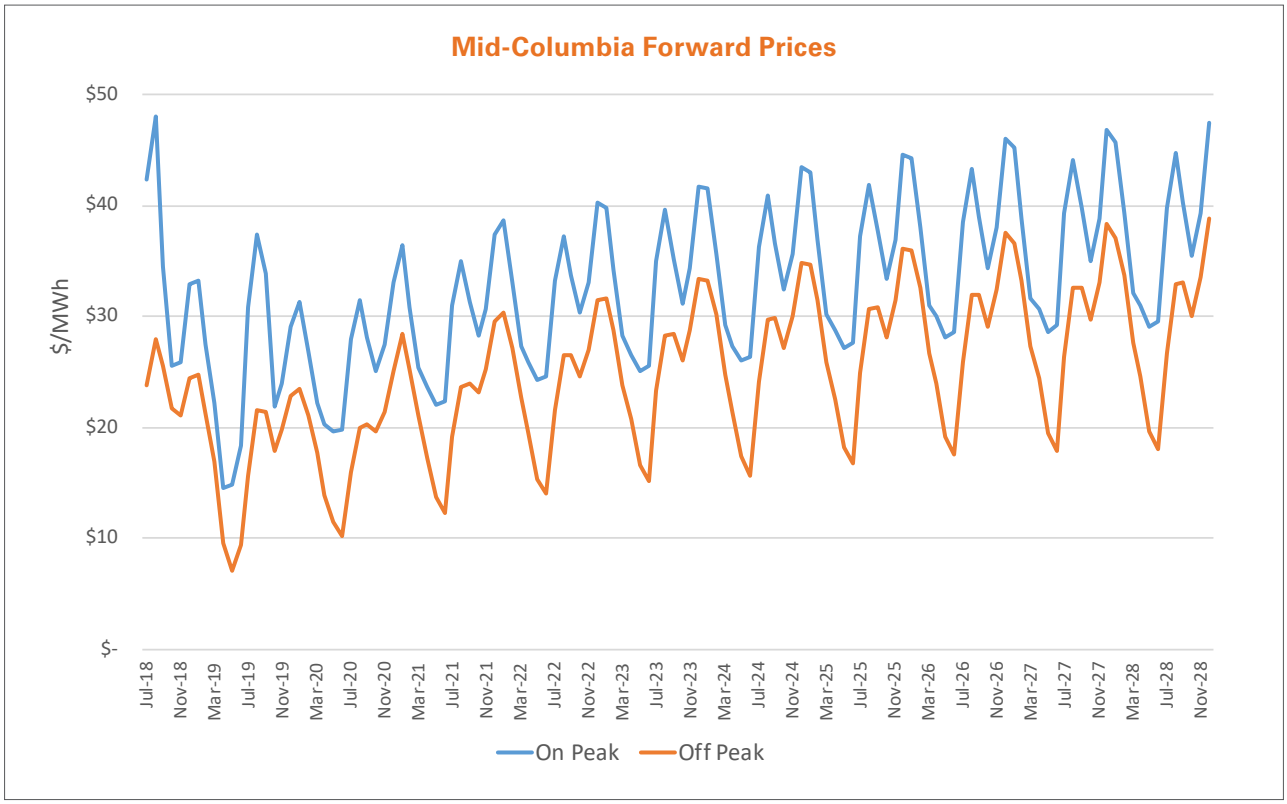
AESO	Alberta Electric System Operator
AVA	Avista Corporation
AZPS	Arizona Public Service Company
BANC	Balancing Authority of Northern California
BCHA	British Columbia Hydro Authority
BPAT	Bonneville Power Administration-Transmission
CFE	Comision Federal de Electricidad
CHPD	PUD No. 1 of Chelan County
CISO	California Independent System Operator
DEAA	Arlington Valley, LLC
DOPD	PUD No. 1 of Douglas County
EPE	El Paso Electric Company
GCPD	PUD No. 2 of Grant County
GRID	Gridforce Energy Management, LLC
GRIF	Griffith Energy, LLC
GRMA	Gila River Power, LP
GWA	NaturEner Power Watch, LLC
HGMA	New Harquahala Generating Company, LLC
IID	Imperial Irrigation District
IPCO	Idaho Power Company
LDWP	Los Angeles Department of Water and Power
NEVP	Nevada Power Company
NWMT	NorthWestern Energy
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric Company
PNM	Public Service Company of New Mexico
PSCO	Public Service Company of Colorado
PSEI	Puget Sound Energy
SCL	Seattle City Light
SRP	Salt River Project
TEPC	Tucson Electric Power Company
TIDC	Turlock Irrigation District
TPWR	City of Tacoma, Department of Public Utilities
WACM	Western Area Power Administration, Colorado-Missouri Region
WALC	Western Area Power Administration, Lower Colorado Region
WAUW	Wester Area Power Administration, Upper Great Plains West
WWA	NaturEner Wind Watch, LLC

There are several sources of power generation in the western grid, including coal, oil, natural gas, nuclear, hydro, solar, and wind resources. The cost to generate power varies across each of these sources. Additionally, the sources have different production characteristics. The "thermal" and hydro sources are highly dispatchable, meaning that their power output can be changed based upon a dispatch schedule. Solar and wind resources, however, fluctuate based on the season, the weather, and the time of day.

Mid-Columbia

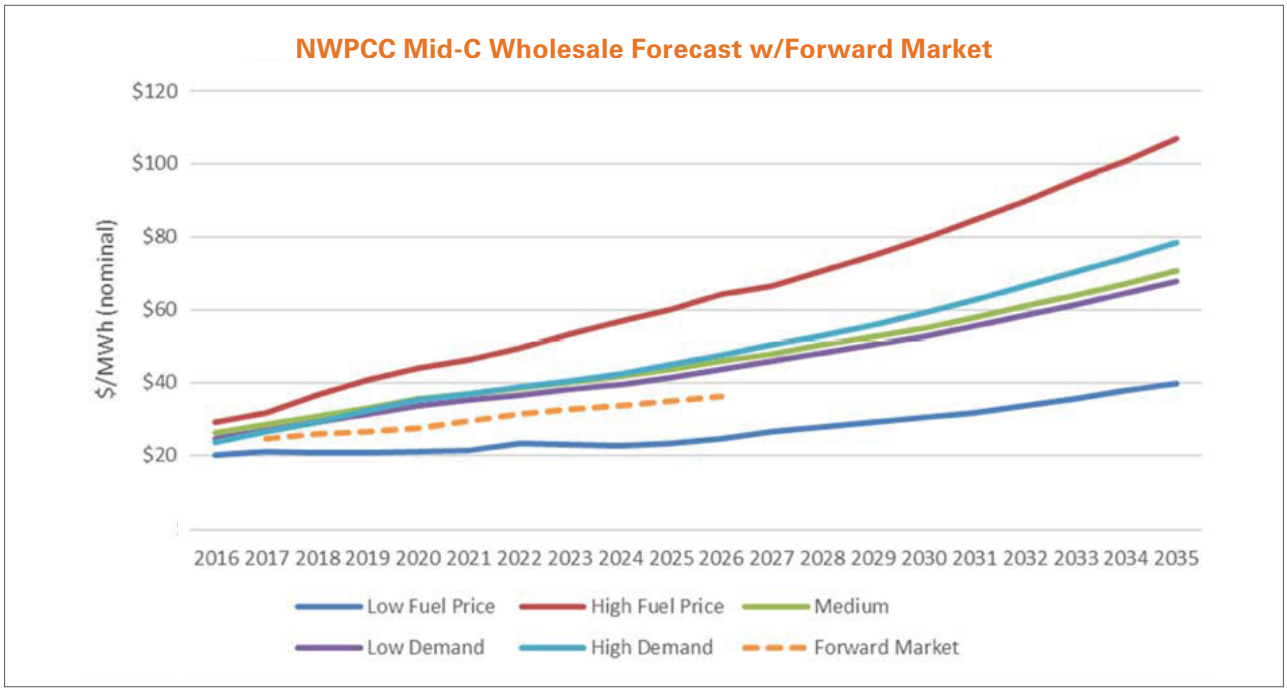
The District benefits from being interconnected with the transmission facilities comprising the main Pacific Northwest energy trading hub – the Mid-C. The Mid-C is one of the most liquid trading hubs in North America. This provides the District with ready access to market energy, both for sales and purchases, as well as market price discovery. The District's information on forward market prices comes from a variety of sources. Daily summaries from the Intercontinental Exchange (ICE) provides a clear forward market indication through 2028. Graph 3-2 represents ICE monthly forward prices at the Mid-Columbia (as of July 16, 2018):

Graph 3-2



In addition to ICE forward prices, the NWPCC provides a forecast of fundamental future markets using the AURORA model and a number of inputs. By using the model and controlling inputs, the NWPCC can evaluate the potential impact of different future scenarios, such as changes in fuel prices or changes in demand, and they also incorporate transmission grid constraints. Graph 3-3 below shows the range of NWPCC wholesale prices from the Seventh Power Plan, with the forward price from ICE included for reference[2]:

Graph 3-3



[2] NWPCC Seventh Power Plan price data is provided in constant 2012 dollars and have been converted to nominal for comparison with the forward price at an assumed inflation rate of 2% per year.

The District has observed that the current forward prices have declined slightly from the forecasts provided by the NWPCC in 2016.

Energy Imbalance Markets (EIM)

This brings us to the idea of the Energy Imbalance Market. Because utilities like Grant PUD need to instantly and constantly adjust the total amount of power being supplied into their system to match the total demand from their customers as efficiently as possible, a convenient and relatively inexpensive market could be used to supply these adjustments at as low a price as possible.

Energy Imbalance Markets have introduced a more efficient option: trading between utilities for small amounts of power in short time increments (5 or 15 minutes) just for the purposes of balancing. This suggests that if a separate utility must use an expensive solution to balance its own load, it can buy its needs from another utility who is selling its power for the next 5 to 15 minutes via the EIM. In the presence of an Energy Imbalance Market, the decision for a utility is mostly one of cost: is it cheaper to buy the power it needs to balance its load on the EIM or to generate the power itself? The same is true for selling power to the EIM for load balancing.

Grant PUD has potentially a lot to gain from an effective EIM. Most of this comes from the fact that it has its own competitively priced hydro generation capacity, desirable green attributes, and control flexibly. Equally important: our energy can be stored as water in our reservoirs. Power storage is a huge problem in the energy industry, but hydro power handles it very well.

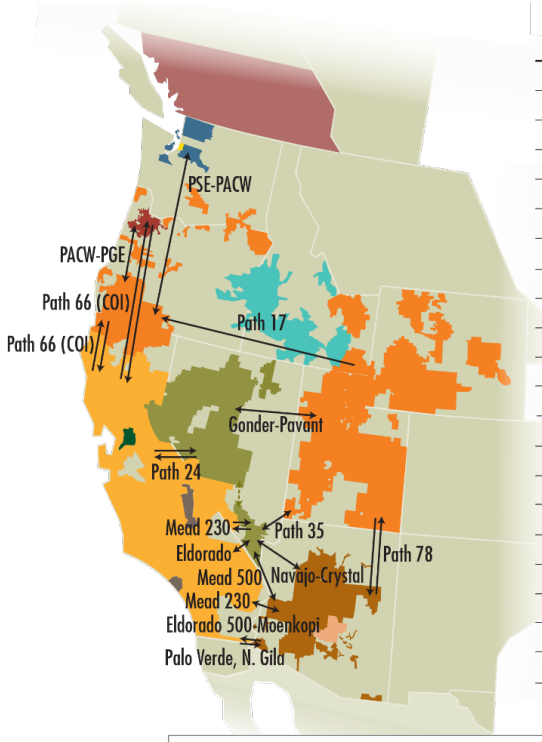
Grant PUD may benefit financially in three primary ways from participating in the EIM:

1. It can reduce its balancing costs, by buying from the market whenever it's cheaper than supplying its own needs.

2. It can reduce its transactions costs by taking advantage of economies of scale offered by a single centrally-organized and independently managed marketplace.

3. It can benefit from better use of existing regional transmission, allowing access to markets as distant as Southern California and Nevada – a region awash with cheap solar generation.

Graph 3-4 (CAISO.COM): **Estimated maximum transfer capacity (EIM entities operating in Q1 2018)**



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	400
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <--> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476

← one direction ↔ bi-directional

- California ISO
- PacifiCorp
- NV Energy
- Arizona Public Service
- Portland General Electric
- Puget Sound Energy
- Idaho Power Company *(entry April 2018)*
- Powerex *(entry April 2018)*
- BANC/SMUD *(planned entry 2019)*
- Seattle City Light *(planned entry 2020)*
- Los Angeles Dept. of Water & Power *(planned entry 2020)*
- Salt River Project *(planned entry 2020)*

The 800-pound gorilla in the market is solar power from California, of which there is a tremendous amount — and thankfully in the middle of the day. Here's what the CAISO energy production looked like on a day in May:

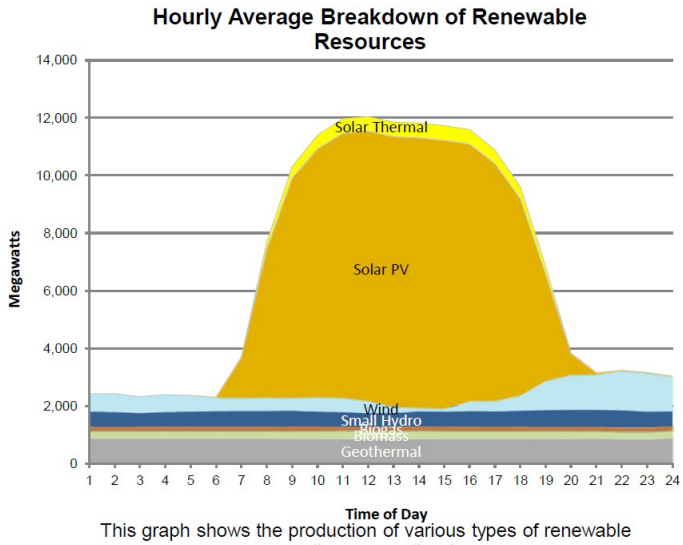
Table 3-5 (CAISO.COM)

24-Hour Renewables Production

Renewable Resources	Peak Production Time	Peak Production (MW)	Daily Production (MWh)
Solar Thermal	14:12	515	5,364
Solar	13:14	9,378	97,835
Wind	21:48	1,423	14,999
Small Hydro	21:20	610	13,165
Biogas	17:04	153	3,584
Biomass	10:40	270	6,205
Geothermal	23:55	898	20,879
Total Renewables			**162,032**
Total 24-Hour System Demand (MWh):			*624,745*

This table gives numeric values related to the production from the various types of renewable resources for the reporting day. All values are hourly average unless otherwise stated. Peak Production is an average over one minute. The total renewable production in megawatt-hours is compared to the total energy demand for the ISO system for the day.

Graph 3-6 (CAISO.COM)



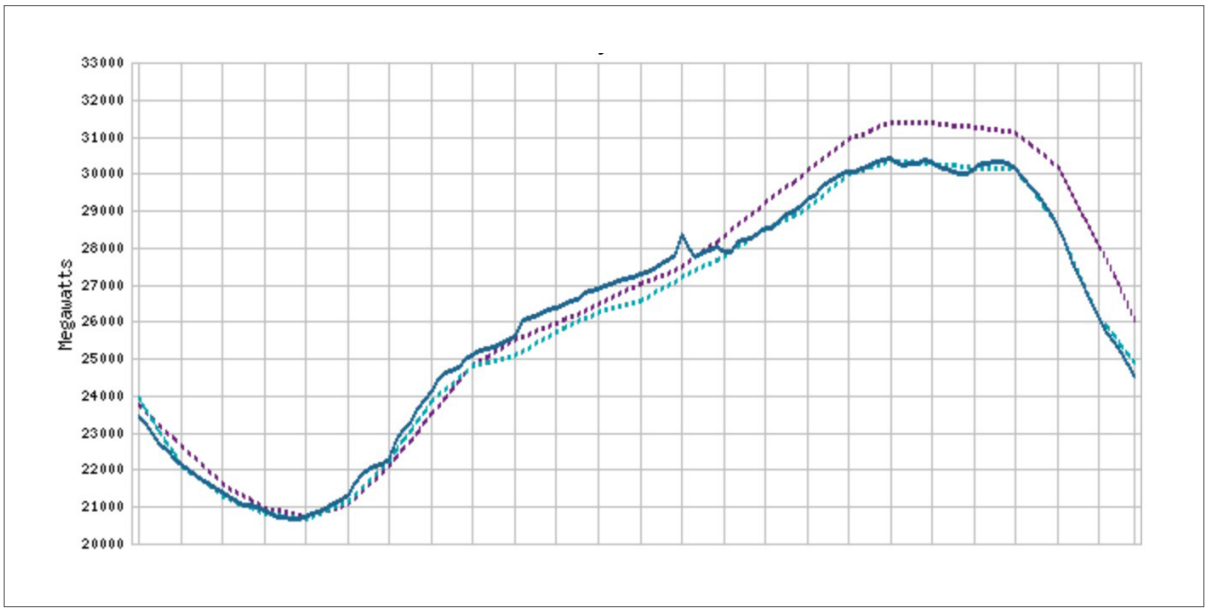
This graph shows the production of various types of renewable generation across the day.

System Peak Demand (MW) *one minute average **30,370**

Time: 17:53

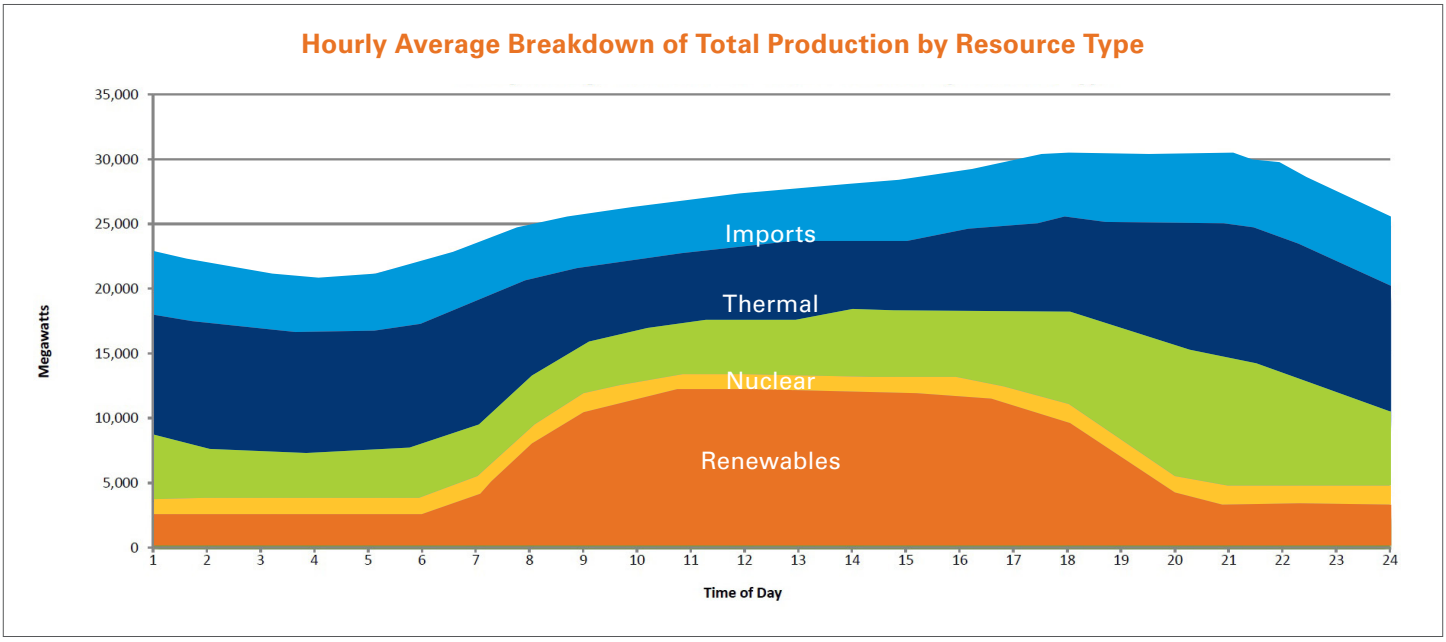
But CAISO's demand curve looks very different (Graph 3-7). On a typical day, load climbs over the day and spikes during the evening — after the solar power is gone:

Graph 3-7 (CAISO.COM)



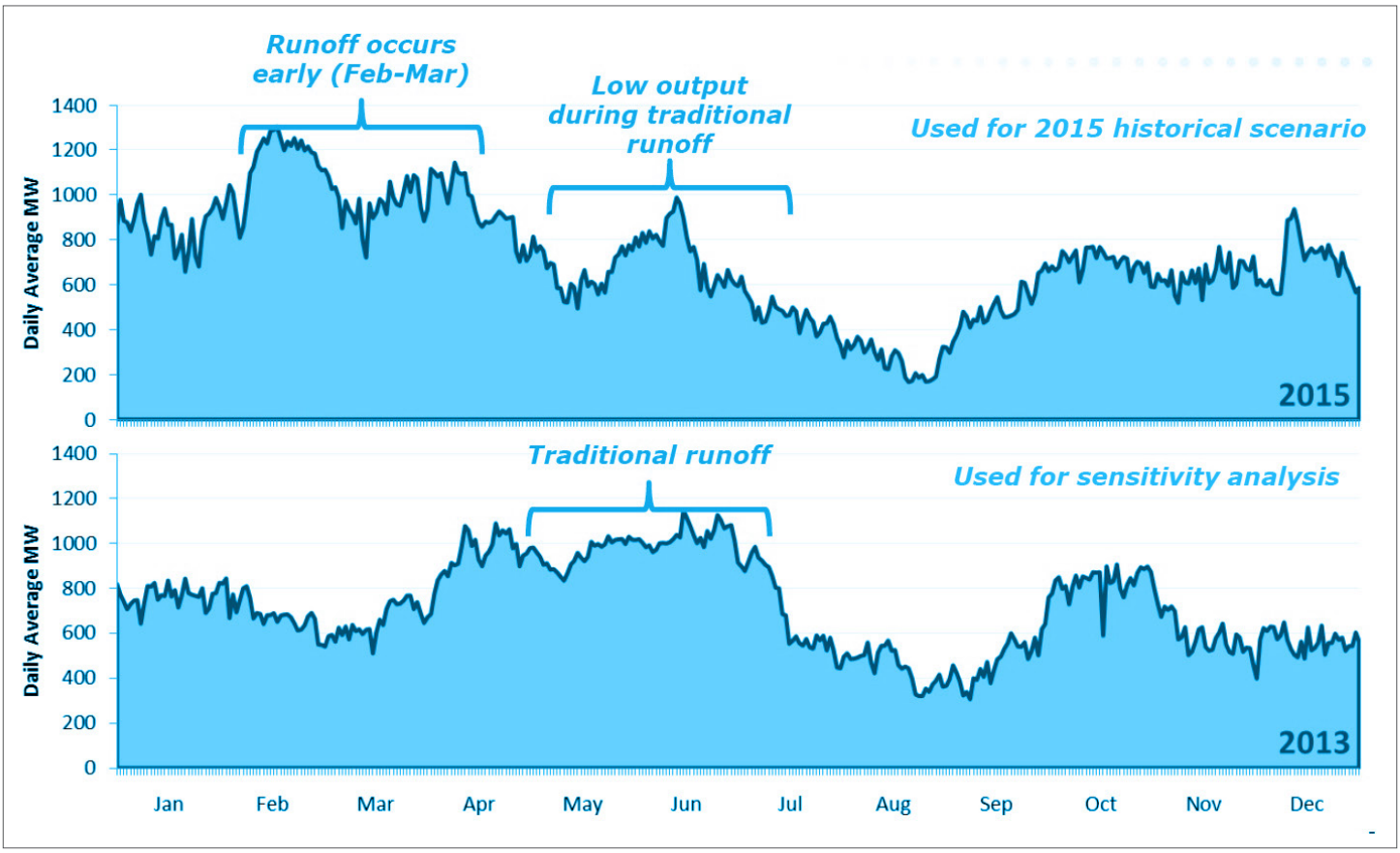
That means CAISO needs to dramatically increase its "reliable power" generation, and its market purchases, in the evening. This may put Grant PUD in a position to deliver power from water stored during day, and allowed to flow just as Californians arrive home for the evening.

Graph 3-8 (CAISO.COM)



However, there are limits to Grant PUD's ability to exploit this due to seasonal variability in the Columbia River flow, managing the needs of fish, recreation, and other water uses. We are also at the mercy of the overall climate: our generation capacity looks very different depending on whether there is a large or small snowpack in a given year, and whether runoff is early or late. Just look at the difference between 2013 and 2015 (Graphs 3-9):

Graphs 3-9 (CAISO.COM)



Also, since Grant PUD's strategic advantage lies mainly with its generation flexibility, its ability to profit from that is driven by volatile market prices. The more price fluctuation there is in the market, the better we do. Fortunately, the data shows that there is a lot of daily price volatility in the CAISO EIM market: both driven by the huge changes in solar production over the course of the day, and also inherent in the balancing needs of the regional system. So, could Grant County PUD benefit from joining the EIM? The answer is, yes, it's possible given where we are located, the needs of the region, and the value of our dams. It's also possible that the EIM will reduce the value of energy delivered at the Mid-C. However the EIM is evolving now and is something the District should evaluate in its planning process.

Further Development of Pacific Northwest Markets

Energy markets have been changing dramatically across North America since the mid 1990's. During this time, they have evolved from supporting traditional bilateral markets whereby utilities served their customers with a combination of their own generation and bilateral energy purchases with their neighbors, to markets supporting bilateral markets and subsequent real-time imbalances (EIM), to organized two-settlement markets capable of handling everything: long-term bilateral trading, day-ahead generation offers and load bids (day-ahead markets), real-time imbalances, and capacity. The earliest and perhaps best example of this evolutionary process has been the PJM Interconnection regional transmission two-settlement market. This example is frequently held up as a reasonable pattern for how the Pacific Northwest markets may evolve over time.

Organized two-settlement markets share common characteristics besides facilitating competition among wholesale suppliers. They also provide non-discriminatory access to transmission by scheduling and monitoring the use of transmission, perform planning and operations of the grid to ensure its reliability, manage the interconnection of new resources, provide market oversight, and increase transparency of transactions on the system. Additionally, actual experience in other organized regional markets such as the PJM Interconnection regional transmission market, the Midcontinent Independent System Operator (MISO) market, and Southwest Power Pool (SPP) market have shown that renewable integration challenges are more easily and efficiently addressed in larger and more coordinated footprints.

Cheap renewables are almost always available due to the large geographic area they are drawn from. In a large geographic area, the wind is always blowing somewhere and the sun is often shining in places not obscured by the clouds affecting others. The effect is a blending of the variability (the "on and off" weather impacts on renewable power) of renewable resources that makes operating the grid easier and less costly. The lower integration cost in turn can mean that the financial benefits to renewable generation owners in markets run by independent system operators are greater. However, there are often winners and losers in any newly organized market and the District's assets may or may not be more valuable in an RTO/ISO. The District will invest time and energy to analyze the evolving markets to determine the best strategy for participation.

The largest benefit of day-ahead markets accrues to participants, both owners of load and generation, who decide a full day before in the day-ahead market which generating facilities will be offered and how much load will be bid to compete in the market. As a result, less efficient power plants are turned on less often because they likely won't be chosen to operate. The ISO/RTO selects resources that run at the lowest costs to meet the expected demand. Less efficient, more polluting resources can't compete against cleaner and more efficient ones.

There is no standard market design for Regional Transmission Markets (RTOs) or Independent System Operators (ISOs), but both must meet the needs of the utilities participating in them. Both manage and provide a central clearing house for transactions (both transmission and generation related), and both should manage the allocation of transmission rights, day-ahead, and real-time purchases. In recent months, WECC utilities and potential organized RTOs/ISOs such as the California Independent System Operator (CAISO), PEAK/PJM RTO, and Southwest Power Pool (SPP) RTO have been in discussions over how the needs of utilities in WECC might benefit from a wider organized market footprint. Regardless of which individual or combination of RTOs/ISOs ends up being organized, they will be counted on to meet their members' needs.

Enhanced Day Ahead Markets (EDAM)

One variant of the overall two-settlement market design currently being discussed by WECC utilities who are interested in gaining the benefits of an organized RTO/ISO without the risk of joining CAISO is the Enhanced Day-Ahead Market. Given the unique nature of the EDAM design, the details have yet to be fully developed. Nonetheless, its overall intent is to provide some of the benefits associated with the more efficient use of generation. District staff is actively monitoring the development of EDAM, with particular attention being paid to how it may affect the District and the Pacific Northwest energy markets.

The risks associated with joining the CAISO are significantly slowing the rate of change in the WECC market. This is primarily due to concerns about the actual independence of the independent system operator and whether the interests of customers outside of California are being fairly served. The District recognizes that good governance and market design are critical to a well-functioning RTO/ISO regardless of utility membership and regional scope. The District has determined that the following RTO/ISO design elements are among those considered essential to a well-designed and governed RTO/ISO:

Independent, Representative Governance

- An independent, non-affiliated Board of Governors ("Board") of a sufficient size to allow the Board

to be diverse and representative of different regions, stakeholders and interests with a clearly defined process for the selection of the Board via a Nominating Committee comprised of representative market and other sectors.

- A strong Market or Member Advisory Committee made up of a broad range of market representatives as a formal advisory channel to the Board itself, including during Board meetings.

- A strong role for state public utility commissions on key market design issues, particularly on resource adequacy and transmission cost allocation, with public power and the Power Marketing Administrations represented on anybody of state regulatory authority representatives.

Transmission Owners can meet existing and future load service obligations at reasonable cost

- Transmission Owners receive sufficient compensation to cover the costs of existing transmission.

- Transmission planning and cost allocation processes that adequately expand the transmission system and fairly allocate transmission costs and recovery.

- Transmission rights holders are ensured congestion/financial rights to mitigate congestion costs.

Fair compensation for capacity and ramping capability and other grid support ancillary services.

- Resource Adequacy/Resource Sufficiency policies which provide a high level of reliability to the market.

- Market rules that provide appropriate compensation for stand-ready capability including spinning reserves, quick start ability, and regulation.

- Processes assure that resources that have been procured for resource adequacy and resource sufficiency perform consistent with obligation and possess firm deliverability to load.

- Resource adequacy and sufficiency rules are applied consistently to all load-serving market participants.

Market Power Mitigation method respects hydro opportunity costs and offer patterns

- Market power mitigation methodology considers the unique structure and role of hydropower in the NW in developing mitigation rules.

- Methods that provide deference, within a reasonable range, to the hydro owner for determination of opportunity costs and offer strategy (i.e. conduct and impact method).

- Methods are applied consistently in local areas that are similarly situated.

Transparent Price Formation

- Market rules are designed to ensure proper economic market function and reliability only and not to include policy objectives of individual participants or stakeholders.

- Market Operator out-of-market purchases or exceptional dispatch actions are minimized except for unexpected reliability situations.

- Proper compensation for environmental attributes, consistent with state policies is allowed to be included in resource offers.

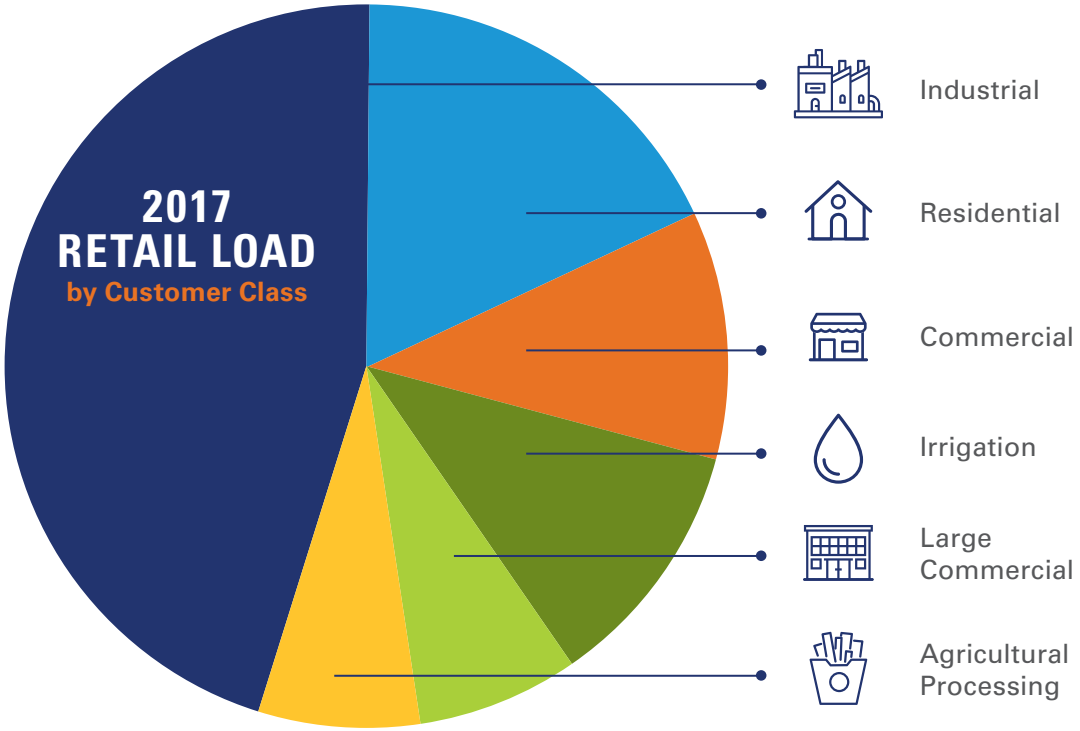
The District does not feel that CAISO currently fulfills these requirements. Fortunately, several competing entities have already begun approaching WECC utilities whose balancing areas are not located within California's borders. These currently include PEAK/PJM and Southwest Power Pool (SPP), and other potential suitors may come forward over time. Peak Reliability (PEAK) is the current reliability coordinator for the majority of WECC, and PJM Connext is a wholly-owned, non-regulated subsidiary of PJM Interconnection, operator of the largest wholesale electricity market in the world and of the largest grid in North America. PEAK/PJM is seeking to continue to provide WECC reliability services, and the market design, governance, market product suite, rules, technology, and organization necessary for WECC utility participants in direct competition with the CAISO.

The Southwest Power Pool is also considered a viable competitor in offering its RTO design, development, and management to WECC utilities whose balancing areas are not located within California's borders. Like the PEAK/PJM offering, SPP has a proven track record running one of the nation's largest RTO's whose states lie on WECC's Eastern border. The essential services both competitors are offering include reliability coordination, market operations and settlement, transmission planning, transmission service and tariff administration. Having a competitive alternative to joining CAISO can significantly increase the likelihood of an effective RTO/ISO structure that is **Regional** in nature, **Independent** from individual states' political influence, **Cost-Effective**, and **Focused on grid reliability.**

4 | ENERGY LOAD FORECAST

The District maintains a detailed projection of anticipated load consumption by the District's retail customers ("Retail Load"). It is helpful to review past Retail Loads to put forecasted Retail Loads into context. The District's 2017 sales to retail customers was 4,685,406 MWh or 535 aMW. 2017 retail sales exceeded prior year sales by 5.5%. The 2017 sales were made to the following customer classes (Chart 4-1) (excluding sales for street lighting and public authorities, which only represents a small amount of the sales):

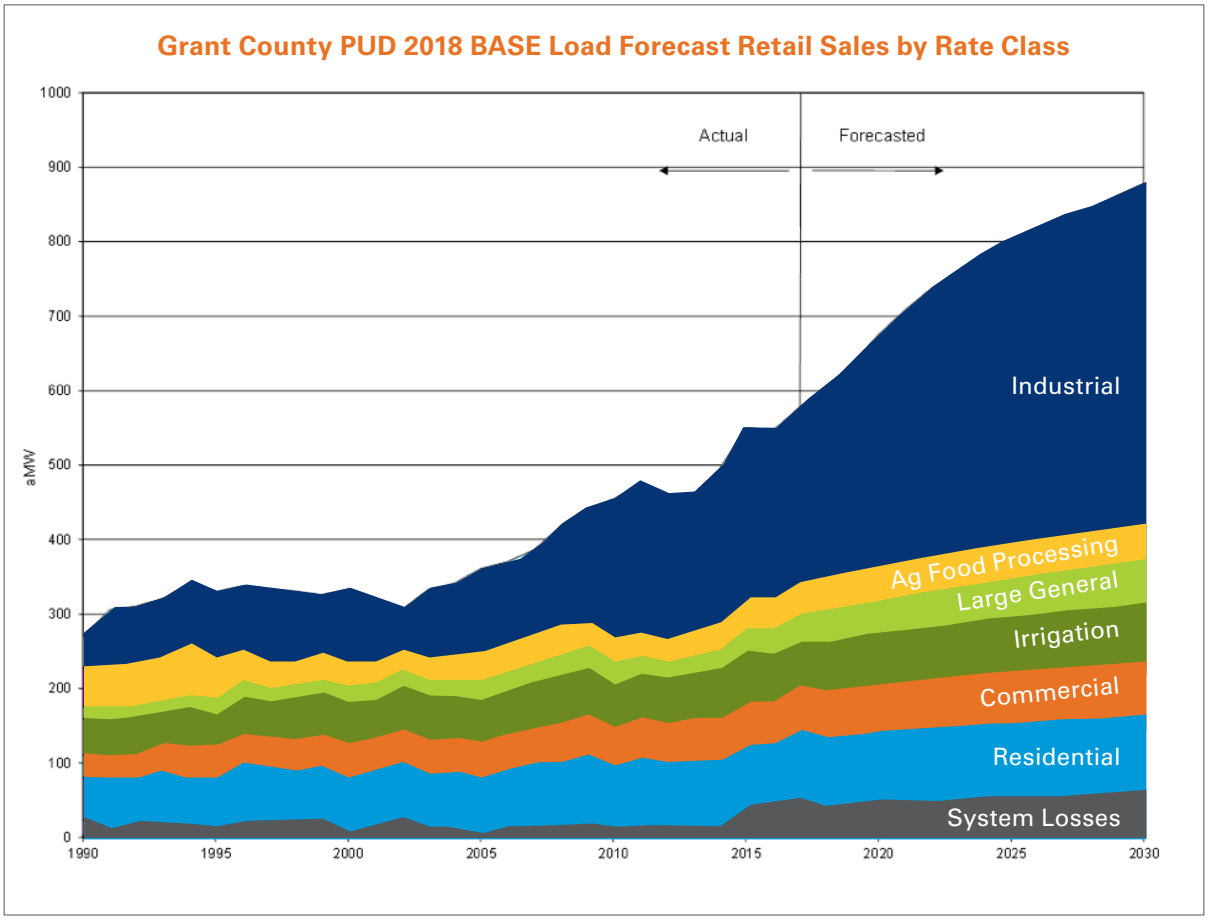
Chart 4-1



In MWh

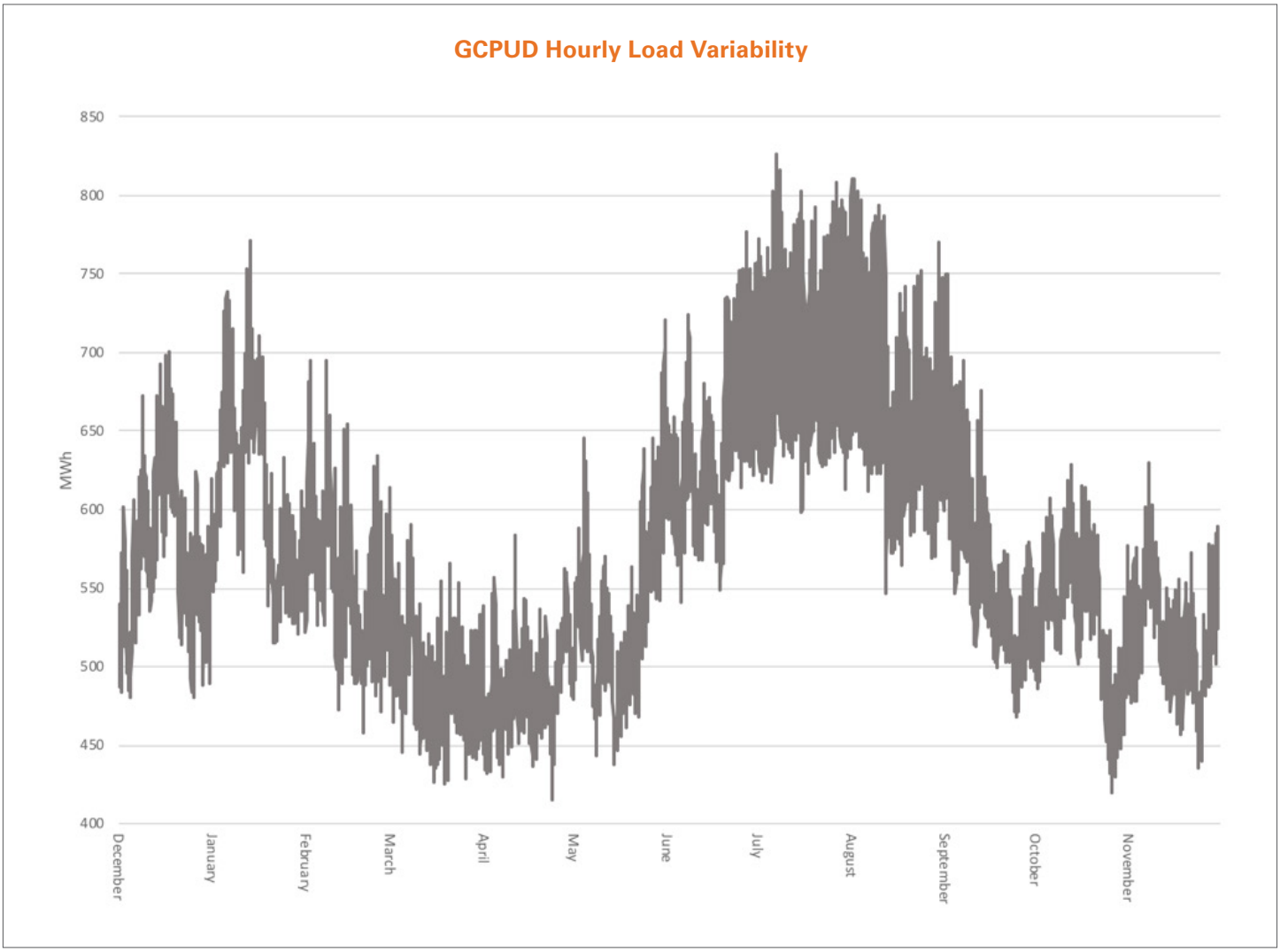
The District's Retail Load is dominated by a handful of large industrial customers. The District also has a significant irrigation load. The irrigation load means that the District's summer and winter peak loads are comparable despite being a northern utility with cold winters. The District's relatively low customer rates have resulted in significant growth in the industrial customer sector that is projected to continue into the future. Growth of industrial load introduces a challenge in terms of forecasting future need. The District's base load forecast by customer class is shown in Graph 4-2:

Graph 4-2



Graph 4-3 represents the load variability experienced in the District from December 2016-November 2017:

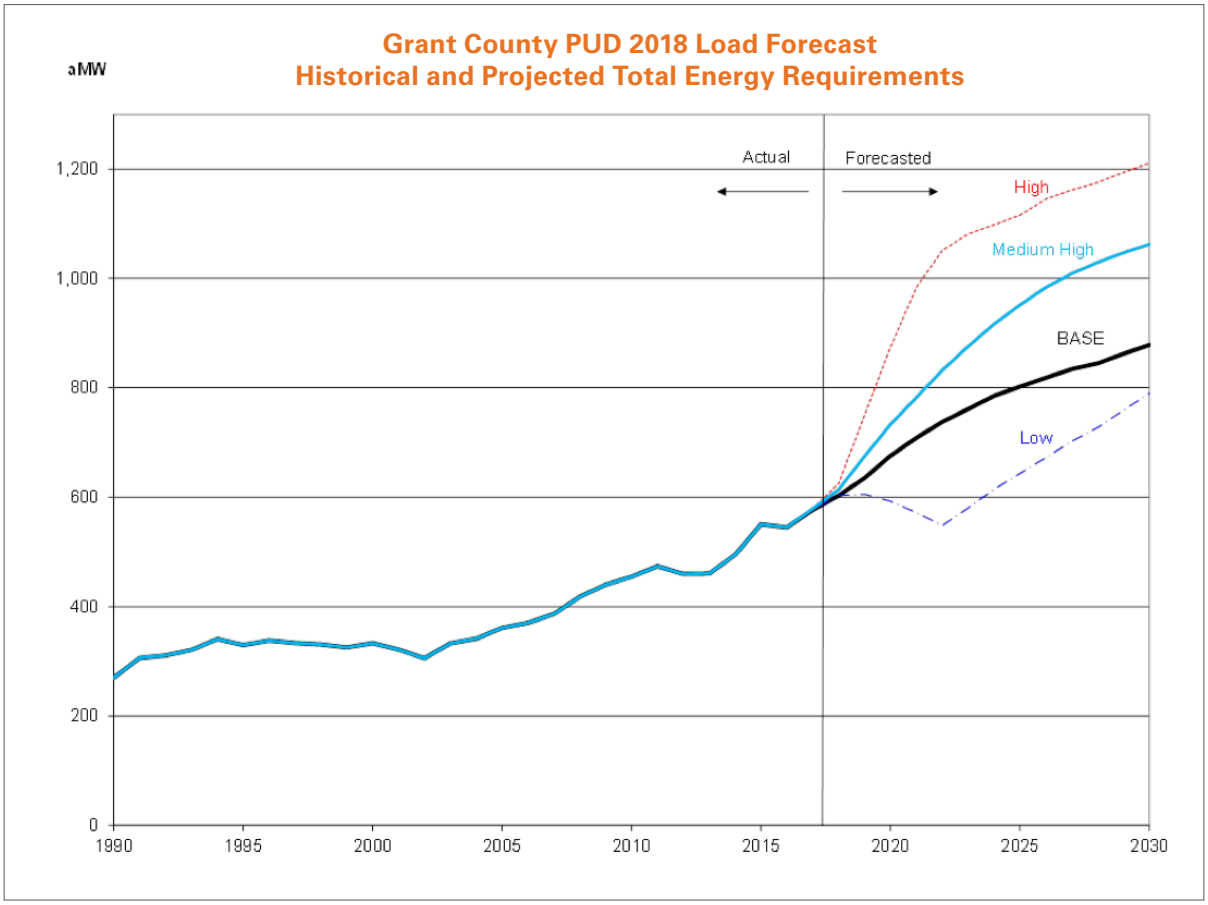
Graph 4-3



Load forecasts are based upon our customers' expected demand for energy assuming normal weather. Hotter or colder than normal temperatures will cause actual load to vary over time. The District's 15% planning margin is used in part as a buffer to ensure our customers' loads will be met.

The District also prepares low, medium high, and high load growth scenarios around the projected forecast to aid in understanding the uncertainty in the forecast. The current low and high sensitivities, compared to the expected (Base) load forecast, are shown in Graph 4-4 below. Note that the low case actually assumes an initial loss of load before returning to a growth curve.

Graph 4-4



From 2006-2016, the District's load has experienced a Compounded Annual Growth rate (CAGR) of 4%. The District's Base forecast has a CAGR of 3.4% through 2030. This is reflective of the District's load forecast which was published in November of 2017. The Medium High forecast is reflective of an accelerated load ramp rate for several customers including data centers and manufacturing loads. The High forecast includes load projections that reflect the possibility of significant load growth, above the base forecast, from existing industrial customers, several of which have unused capacity they could access and the District is obligated to serve. The Low load forecast reflects the results of a major technology shift scenario that would require lower power consumption for a period of time from data center loads. The District has used all of these forecasted load outcomes and their respective probability of occurring in developing our Integrated Resource Plan.

5 | CONSERVATION AND EFFICIENCY RESOURCES

The District conducted a Conservation Potential Assessment (CPA) in 2017 to estimate the conservation potential for the coming 20 years. The District has historically been able to meet the targets set for conservation. Due to the current wholesale market rates and concern of rate increases for our customers, the District has focused the conservation efforts on the industrial customers. The District continues to offer several rebate programs for residential and non-residential applications in our BPA territory. The full CPA has been attached as Appendix 4 so that the analysis and methodology are clearly provided.

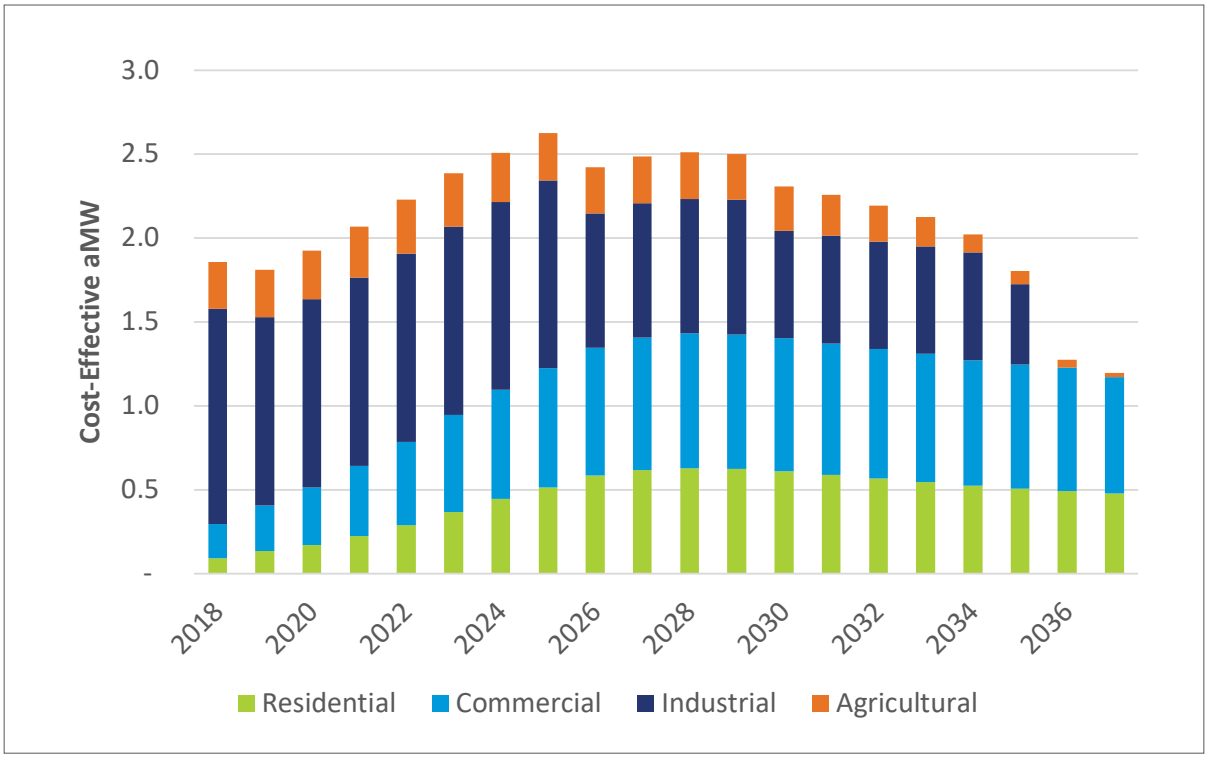
The conservation potential analysis evaluated four sectors including: residential, commercial, industrial, and agricultural. The industrial sector is where the District receives the greatest gains by installing more energy efficient cooling and power supplies in data centers, lighting, upgrading refrigerated storage, and improving processes for saving power. The agricultural sector represents the second greatest potential for conservation using variable frequency drives, irrigation hardware and custom irrigation system improvements.

The following table and chart are taken directly from the CPA to illustrate the base case of where the conservation potential is through 2037. For the high, low, or accelerated based cases, please see the Appendix 4 containing the CPA. These volumes have been deducted from the District's expected load forecast and in the RESOLVE model.

COST EFFECTIVE POTENTIAL - BASE CASE (AMW) | Table 5-1 (District 2017 CPA)

	2 Year*	6-Year	10-Year	20-Year
Residential	0.23	1.28	3.44	9.01
Commercial	0.47	2.31	5.22	12.86
Industrial	2.40	6.89	10.74	16.02
Agricultural	0.56	1.80	2.92	4.63
Total	**3.67**	**12.28**	**22.32**	**42.52**

Graph 5-2 (District 2017 CPA)

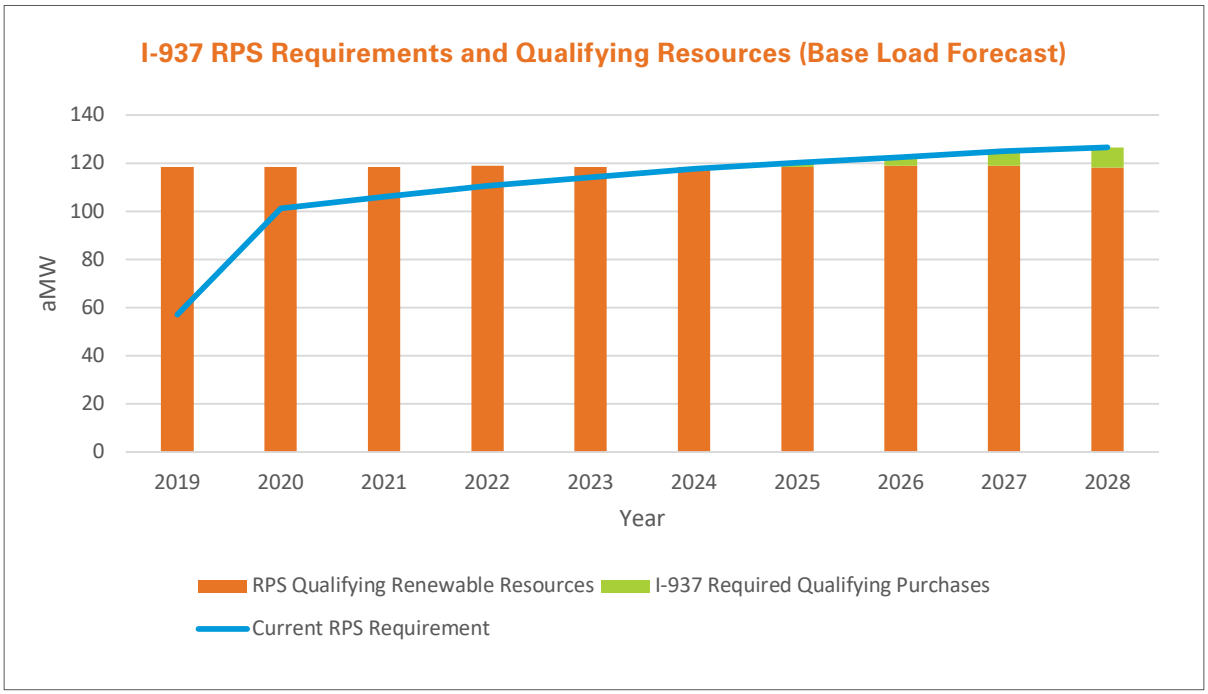


The District will use the information from the CPA as well as this IRP to pursue its cost-effective conservation targets. The savings to participating retail customers will accumulate for many years. For example, District staff estimates the conservation efforts during 2018 are expected to save participating customers a total of $5.7 million through 2028.

6 | RENEWABLE PORTFOLIO STANDARD (RPS)

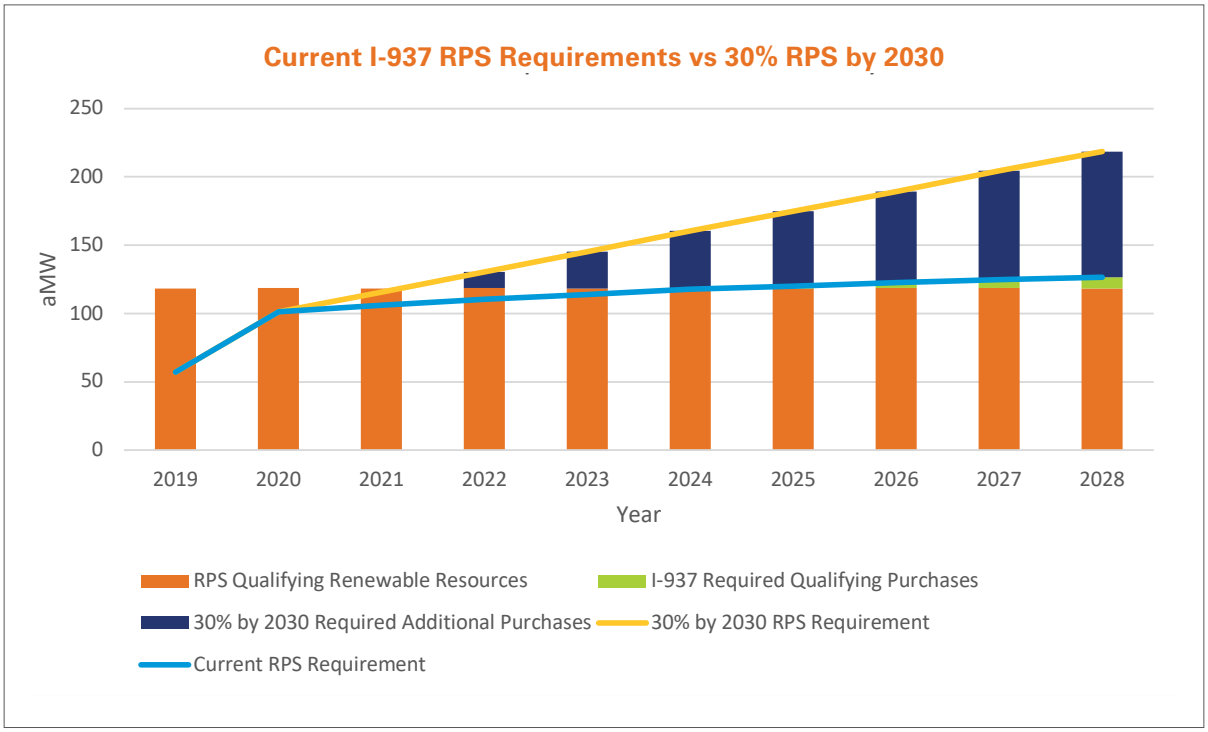
The District will meet the Washington State RPS (I-937) through its current investment in renewable generating projects and future investment in new renewable capacity and/or Renewable Energy Credits (REC). The District's current sources include the Wanapum and Priest Rapids Top Spill Fish Bypasses, qualifying improvements made to Wanapum and Priest Rapids turbines and generators, upgrades to more efficient unit dispatch processes, and the purchase of a portion of the Nine Canyon Wind Project. Based on these investments in renewable generation and current load growth projections, the District is projected to meet the RPS requirements until 2025 (Graph 6-1).

Graph 6-1



Given the uncertainty of environmental policies outlined in Section 2, variability in the RPS requirements is a risk to the District and this IRP. The District has modeled how an increase in the RPS standards could affect the resource acquisition. Graph 6-2, below, demonstrates the additional qualifying renewable resources and/or RECs that would be required if Washington were to increase the RPS to 30% by year 2030.

Graph 6-2



7 | EXISTING SUPPLY & RESOURCES

The District currently meets its load and other energy obligations with a portfolio of supply resources anchored by the District's right to the output of Wanapum and Priest Rapids Hydroelectric Dams, collectively referred to as the Priest Rapids Project (PRP). The District augments the output of these facilities with contracts for Nine Canyon wind and three small irrigation projects (Quincy Chute, Potholes East Canal (PEC), and Wapato). The District also receives power from the Bonneville Power Administration to meet the load in the Grand Coulee area of Grant County. Historically, this portfolio has provided a foundation for meeting the District's load in a cost-effective manner.

Significant attributes of Grant generation resources:

- Capacity: the maximum output of electricity that a generator can produce under ideal conditions. Capacity levels are normally determined as a result of performance tests and allow utilities to project the maximum electric load that a generator can support. Capacity is generally measured in megawatts or kilowatts.

- Energy: the amount of electricity that is produced over a specific period of time. This is usually measured in kilowatt-hours, megawatt-hours, or terawatt-hours.

- Ancillary Services: the specialty services and functions provided by the electric grid that facilitate and support the continuous flow of electricity so that supply will continually meet demand. The term ancillary services is used to refer to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. These services generally include frequency control, regulation, load following, energy imbalance, spinning reserves, operating reserves, scheduling, system control, and dispatch. Some of the highest quality ancillary services are provided by generators with large spinning turbines.

- Energy Storage: in hydro projects like the PRP, storage is realized through the ability to store water in reservoirs to be run through turbines when the energy is desired.

- Carbon-Free Energy and Incremental Hydro Renewable Energy Credits: generators that are capable of producing carbon-free power will have an advantage over generators that release carbon whenever there is an explicit price on carbon. These carbon-free attributes can be monetized in the form of Renewable Energy Credits.

THE GENERATING RESOURCES AVAILABLE TO THE DISTRICT TO MEET ITS OBLIGATIONS:

The Wanapum Development

The Wanapum Development consists of a dam and hydroelectric generating station with a nameplate rating of 1,185 MW. Located on the Columbia River in Grant and Kittitas Counties, about 160 air miles northeast of Portland, Oregon, 129 air miles southeast of Seattle, Washington, and 18 miles upstream of the Priest Rapids Development, the Wanapum Development includes certain switching, transmission and other facilities necessary to deliver electric output to the transmission networks of the District, Bonneville and certain other power purchasers.

The Priest Rapids Development

The Priest Rapids Development consists of a dam and hydroelectric generating station with a nameplate rating of 953 MW. Located on the Columbia River in Grant and Yakima Counties about 150 air miles northeast of Portland, Oregon, 130 air miles southeast of Seattle, Washington, and 18 miles downstream of the Wanapum Development, the Priest Rapids Development includes certain switching, transmission and other facilities necessary to deliver the electric output to the transmission networks of the District, Bonneville and certain other power purchasers.

PRP provides the District with all of the significant attributes of value including energy, capacity, ancillary services, energy storage, and carbon-free green attributes defined above. Often, these are used exclusively to serve customers' needs. Any excess has value and can be marketed. These large hydroelectric resources have been the District's foundational supply of carbon-free electricity. "Deep Decarbonization and Hydropower" (See Appendix 5) highlights the critical role hydropower plays in the national quest to reduce carbon emissions.

EUDL Market Purchases

The District has the right to receive financial resources from the Priest Rapids Project to purchase power to serve the Estimated Unmet District Load (EUDL). The financial resources are limited to approximately 30% of the market value of the output of PRP in any given year. The energy and capacity are not received directly from the Priest Rapids Project but through market purchases. This provision allows the District to serve loads up to roughly 30% of the output of the Priest Rapids Project at the net cost of production for the Priest Rapids Project. In the accompanying graphs, this resource is labeled "EUDL Market Purchases." The District recognizes that this is a financial position that needs to be converted to a physically firm position though the course of the District's hedging strategy and consistent with the Integrated Resource Plan. The District assumes that there will be physical capacity available in the market to meet these objectives. The District will evaluate liquidity within the market and make strategic adjustments to meet physical firm needs.

Bonneville Power Administration Contracts

Bonneville charges a cost-based rate, meaning it only recovers its costs when setting rates. Bonneville conducts a rate case every two years to reset these cost-based rates. The District's Priority Firm (PF) power contract with Bonneville, effective October 1, 2011, and terminating October 1, 2028, provides that Bonneville serve only the District's loads in the Grand Coulee area (5 aMW or roughly 1% of the total District load), which is a small area not interconnected to the District's transmission system. The District does not have a contract with Bonneville to serve any other District load. Grant PUD has the right to exercise its statutory rights to apply for more PF power from BPA after 2028. The District will continue to monitor BPA's rates in order to evaluate the value of expanding the PF power commitment post 2028.

Nine Canyon Wind Project

The District entered into a power purchase agreement with Energy Northwest for the purchase of 25% of the generating capacity of Phase I of the 48.1 MW Nine Canyon Wind Project. The District now receives 12.54% of the expanded Phase I, II and III Nine Canyon Wind Project, which is equivalent to the 25% share of the original Phase I project. The power purchase agreement will terminate on July 1, 2030. The Nine Canyon Wind Project is a wind energy generation project located approximately eight miles southeast of Kennewick, Washington, in the Horse Heaven Hills. In 2016, the District received approximately 31,278 MWh of wind generation output from the project and 28,227 MWh in 2017. This resource provides capacity and produces carbon-free energy with RECs.

Quincy Chute Project

Under an agreement with three irrigation districts, Grant PUD operates and purchases the entire capability and output of the Quincy Chute Project, a 9.4 MW hydroelectric generating facility operating seasonally during the irrigation season (March through October). The District financed, designed and constructed the project and is responsible for operation and maintenance during the period of the agreement, which expires in 2025. The Quincy Chute Project began commercial operation on October 1, 1985, and its net energy generation was 26,370 MWh in 2016 and 30,866 MWh in 2017. This resource produces capacity and carbon-free energy. Due to the uncertainty of the renewal of this contract, it does not show up as a resource beyond the expiration date in 2025. As we get closer to the expiration of the contract, Grant PUD will evaluate this resource and may negotiate with the irrigation districts on a possible new contract.

P.E.C. Headworks Power Plant Project

Under an agreement with three irrigation districts, Grant PUD operates and purchases the entire capability and output of the 6.5 MW generating facility at the P.E.C. Headworks at the O'Sullivan Dam, which operates during the irrigation season (March through October). The District financed, designed and constructed the project and is responsible for operation and maintenance during the period of the agreement, which expires in 2030. The P.E.C.

Headworks Project began commercial operation on September 1, 1990, and its net energy generation was 21,876 MWh in 2016, and 15,517 MWh in 2017. This resource produces capacity and carbon-free energy.

Wapato Hydroelectric Project

The District entered into a long-term purchase power agreement with the Yakama Nation for the output of the Wapato Hydroelectric Project. The Wapato Hydroelectric Project consists of two plants and is located within the boundaries of the Yakama Indian Reservation in Yakima County, Washington, and irrigates about 142,000 acres. The rated capacities of the Wapato Hydroelectric Projects are 1.6 MW and 2.5 MW. The hydroelectric output from the Wapato Hydroelectric Project was approximately 1,350 MWh in 2016 and 0 MWh in 2017 due to mechanical issues at the project. The Yakama Nation is responsible for the operations and maintenance of this project. Future production from this resource is outside the District's control. The output is also seasonal and concurrent with the irrigation season which is May through October. This resource produces capacity and carbon-free energy.

Shell and Avangrid Contracts

The District entered into contracts to sell a 10% slice of the Priest Rapids Project to Avangrid Renewables, Inc. for the term of July 1, 2015 through June 30, 2018. An agreement with Avangrid is in place to extend the 10% slice sale through the end of calendar year 2018. The District is competitively marketing this 10% slice for calendar years 2019-2022.

The District also entered into an Agreement for Pooling of Priest Rapids Project Physical Output (the "Pooling Agreement") with Shell Energy North America ("SENA") in September 2015. Under the Pooling Agreement, the District provides SENA 53.3% of the District's 63.3% share of the capacity in the Priest Rapids Project, and SENA provides to the District firm power sufficient to meet the Electric System's retail load forecast, adjusted for the portion of Electric System load that is expected to be met with other District resources ("District's Load Forecast"). In addition, SENA provides scheduling services for the District, including managing power schedules, and the District provides flexibility to SENA within the District's control area. The term of this Pooling Agreement runs through September 2020.

Under the Pooling Agreement, SENA has rights to the actual output of 53.3% of the Priest Rapids and Wanapum Hydroelectric Project Projects, which varies with water conditions, and in turn provides firm power to meet the District's load, regardless of the actual output of the Priest Rapids and Wanapum Hydroelectric Projects.

The District's hedging strategy will continue to use slice sales similar to Shell and Avangrid to mitigate water volume risk. Slice sales allow the District to transfer water risk to counter parties in exchange for average water. In addition, the District has realized a premium associated with environmental attributes and associated ancillary services. This strategy has proven to be the most effective and least-cost approach currently available to the District.

Quincy Chute Project

8 | COMPARISON OF RESOURCE OPTIONS

The District has identified specific generation resources to consider under its different forecasting assumptions. These include natural gas, wind, solar, and battery storage. The District does not anticipate owning any of these resources in the next ten years, but significant load growth or a change in regulatory requirements may make ownership beneficial. Assuming no change in the carbon constraints in Washington, the District projects adding combined cycle natural gas generation through market purchases or purchase power agreements beginning in 2027. If there is a significant increase in Renewable Portfolio Standards in Washington, the District would need to add carbon-free generation or RECs starting in 2025. Medium High or High load growth would necessitate acquiring these additional resources sooner.

The RESOLVE model provides extensive modeling and analysis of resource options for future capacity expansion plans. This analysis provides the following view of different generating options for the District. Table 8-1 below is a summary of the potential new resources used by RESOLVE that would provide a good option for the District for future portfolio augmentation.

Table 8-1 (RESOLVE)

Technology	Size (MW)	Forecast Capacity Factor	Levelized Cost of Energy ($/MWh)
Non-Renewable			
Combined Cycle Combustion Turbine	500	75%	$84
Reciprocating Engine	100	10%	$286
Aeroderivative Gas Turbine	100	10%	$286
Frame Gas Turbine	200	10%	$254
Renewable			
Solar (Washington)	20+	19%	$78
Wind	30	30%	$63
Battery – Lithium	1	15%	$81

However, at this time, the current forward market provides a more cost-effective option for serving District load growth than contracting for or constructing new generating assets. Nonetheless, it remains clear that the forward market does not provide price certainty nor dependable capacity to meet loads beyond the term of actual signed agreements. Dependence on markets should be viewed carefully and critically with respect to these factors. In addition, the current low forward market price could trigger the sale of distressed assets and may present the District with opportunities to procure offtake purchase agreement or acquire generating assets at prices lower than forecasted by RESOLVE.

9 | INTEGRATED RESOURCE PLAN

The District evaluates the various external and internal forces that can affect the size and shape of the load it serves and how to meet that load based on anticipated market prices, resource availability, and delivery constraints. The District uses a commercially available production cost planning model, RESOLVE, to calculate the least-cost alternatives based on various assumptions pertaining to load growth and possible legislative requirements associated with carbon emissions. This least-cost modeling approach is consistent with Grant PUD's mission to efficiently and reliably generate and deliver energy to our customers. The District examined 16 different scenarios representing the most probable loads and carbon legislation/requirements. The Base Case represents the expected outcome for the District under current carbon regulation (I-937 as presently enacted). The District recognizes the inherent uncertainty in these model assumptions and these results are reflected in the scenarios and appendices below. The District is constantly monitoring changes to forecasted loads, resource availability, market prices, market liquidity, and legislation that could affect the price and/or availability of resources. Each of the 16 scenarios modeled in the IRP assumes that we are using our current physical resources or will acquire firm energy and capacity to meet our expected monthly load. The District will also acquire firm capacity options if necessary to meet our 15% planning margin. Table 9-1 below describes the 12 scenarios selected for discussion in this IRP. A 100% Carbon-free by 2050 scenario was modeled, but modeling results were the same as the Current I-937 + Carbon Tax scenarios over the planning horizon and therefore are not shown in this report. Attaining 100% Carbon-free by 2050 does result in substantially higher customer costs beyond 2035.

IRP SCENARIOS | Table 9-1

Current I-937 Requirement	Current I-937 + Carbon Tax	Increase RPS to 30% by 2030
Low Load under current law	Low Load with carbon tax	Low Load/RPS increase
Base Load under current law	Base Load with carbon tax	Base Load/RPS increase
Medium High Load under current law	Medium High Load with carbon tax	Medium High Load/RPS increase
High Load under current law	High Load with carbon tax	High Load/RPS increase

Summary Of RESOLVE Model

The District has utilized the RESOLVE resource investment model in evaluating the least-cost resources the District should procure to meet its future loads. RESOLVE uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in IRP can be achieved without relying on assumed future technological breakthroughs. The full range of resource options considered by RESOLVE in this study is shown in Table 9-2. More information on the RESOLVE model is available in Appendix 1.

RESOURCE OPTIONS CONSIDERED IN RESOLVE | Table 9-2

Resource Option	Examples of Available Resources	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines • Repowered CCGTs	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Geothermal • Hydro upgrades • Solar PV • Wind	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load • Hydro resources have full up and downward flexibility to balance load.
Energy Storage	• Batteries (>1 hr) • Pumped Storage (>12 hr)	• Stores excess energy for later dispatch • Contributes to meeting minimum generation and ramping constraints
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Interruptible tariff (ag) • DLC: space & water heating (res)	• Contributes to planning reserve margin needs

Base Case

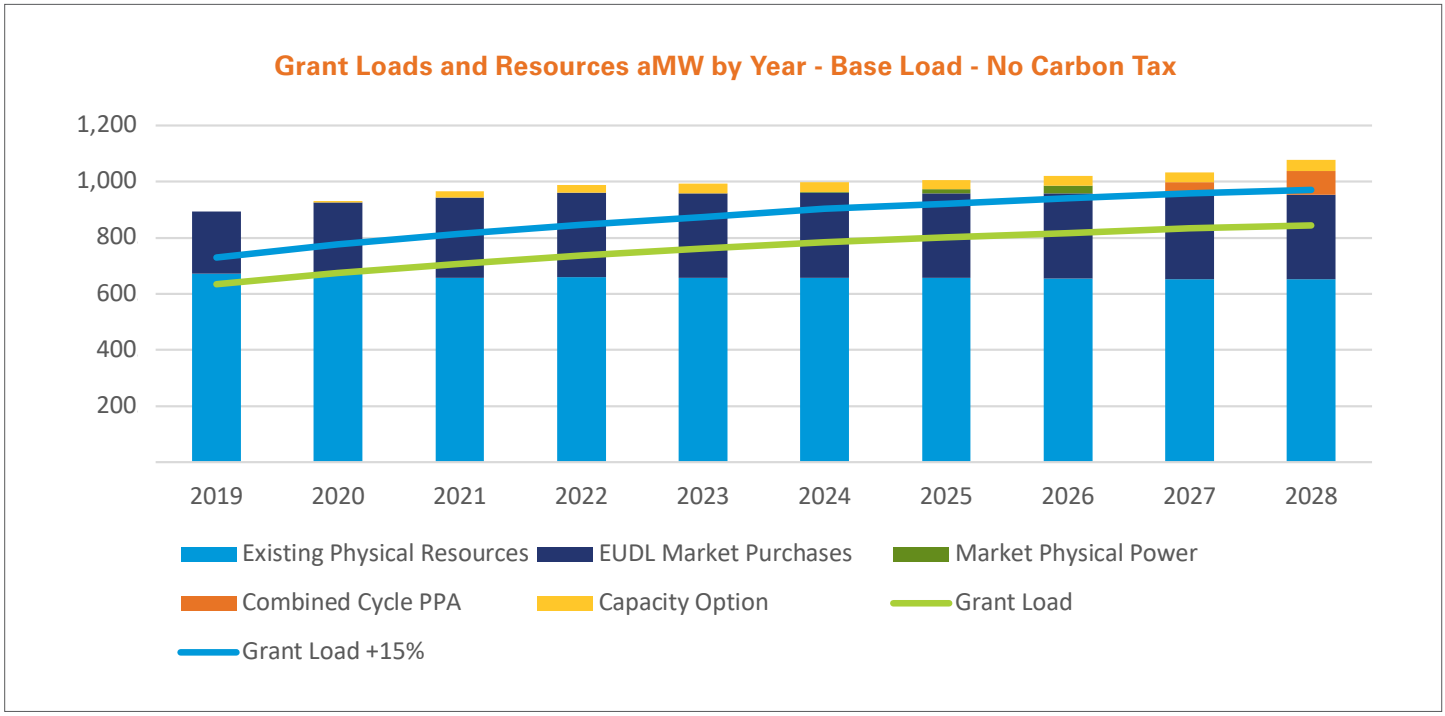
The Base Case represents the District's least-cost path forward to serve expected load requirements under current market conditions. This means the District is using the base load forecast, existing resources, and selecting new resources under the current legislative environment (i.e. current I-937 RPS and no price on carbon). Under the Base Case, the District has enough existing capacity to meet expected load growth on an annual basis through the entire 10-year planning horizon (Graph 9-3). However, the District is forecasting to be capacity deficit in late summer by 2024 but is not forecasting a winter capacity deficit until December 2028. Under the Base Case, the District is able to meet expected load through 2026 with existing resources, EUDL, and Market Purchases (for volumes less than 50 aMW annually). In addition, the RESOLVE model recommends the District use capacity call options on a natural gas combustion turbine to meet the 15% planning margin. Starting in July of 2027, the District expects to enter into a purchase power agreement for capacity (85 aMW) on a natural gas combined cycle resource (Graph 9-4). This decision is based a need to fill a large capacity need through the majority of the year with the assumption that this volume was large enough to justify entering into a Purchase Power Agreement (PPA). In many cases, natural gas technologies are selected by the RESOLVE model. However, the District will meet its energy needs based on the least-cost resource available, which may include other technologies such as hydro power. The District's 10-year planning horizon results can be seen on a monthly basis in Graph 9-5.

The District has analyzed the costs and benefits of building and operating a power resource verses purchasing power through contracts (PPAs). Given the District's capacity requirements over the next ten years, the model indicates that PPAs are the least-cost option for the District. This plan is supported by the District's expectation that natural gas-burning capacity will be available.

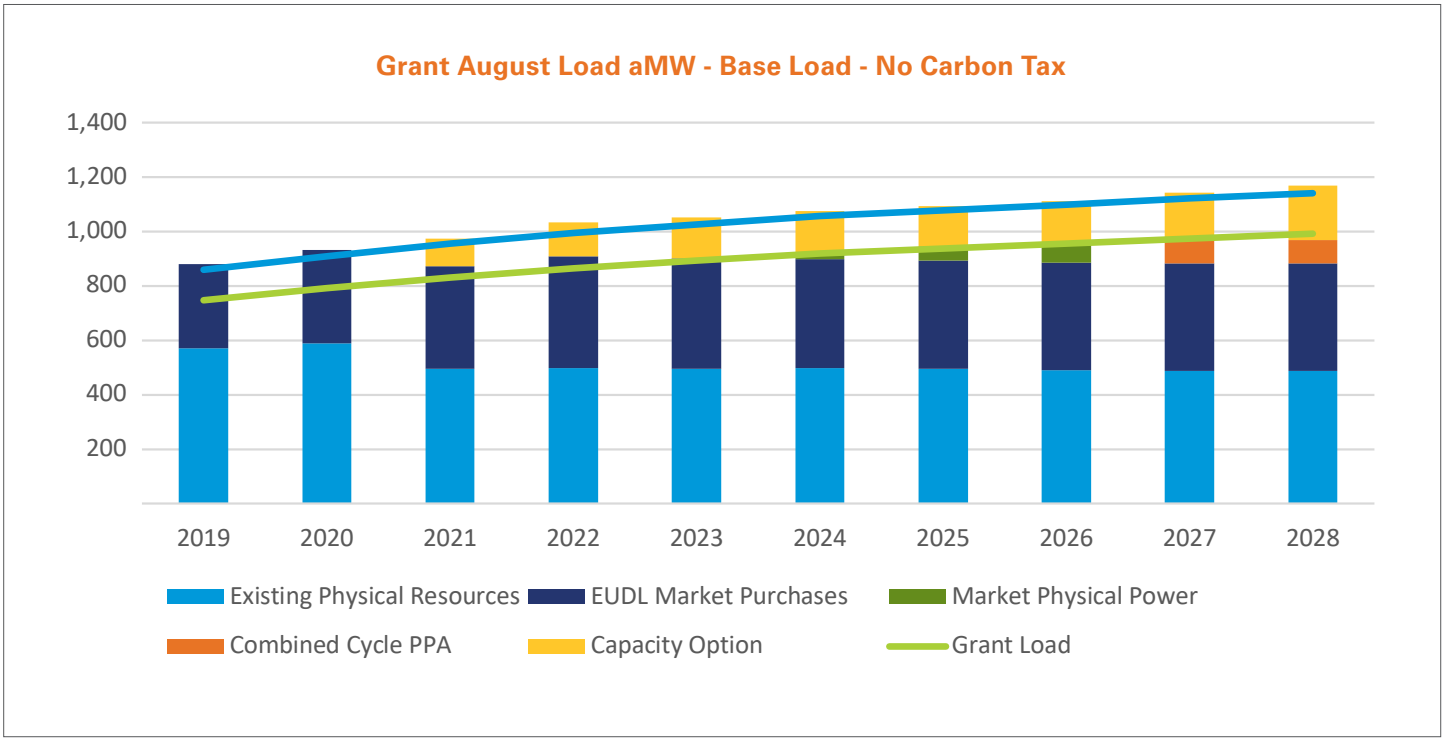
The graphs below represent the District's annual and summer cases which may include:

- **Existing Physical Resources:** PRP, Nine Canyon, Quincy Chute, PEC, Wapato, BPA, and Shell exchange agreement
- **EUDL Market Purchases:** Assumed to be converted to firm physical energy up to Grant Load
- **Market Physical Power:** Firm physical energy purchases
- **Combined Cycle PPA:** Purchase Power Agreement
- **Capacity Option:** : call option on physically firm capacity from a natural gas combustion turbine
- **Grant Load:** Base load forecast (See Section 4)
- **Grant Load +15%:** Planning margin on load
- **Renewable PPA:** Purchase power agreement for renewable resources necessary meet RPS requirements

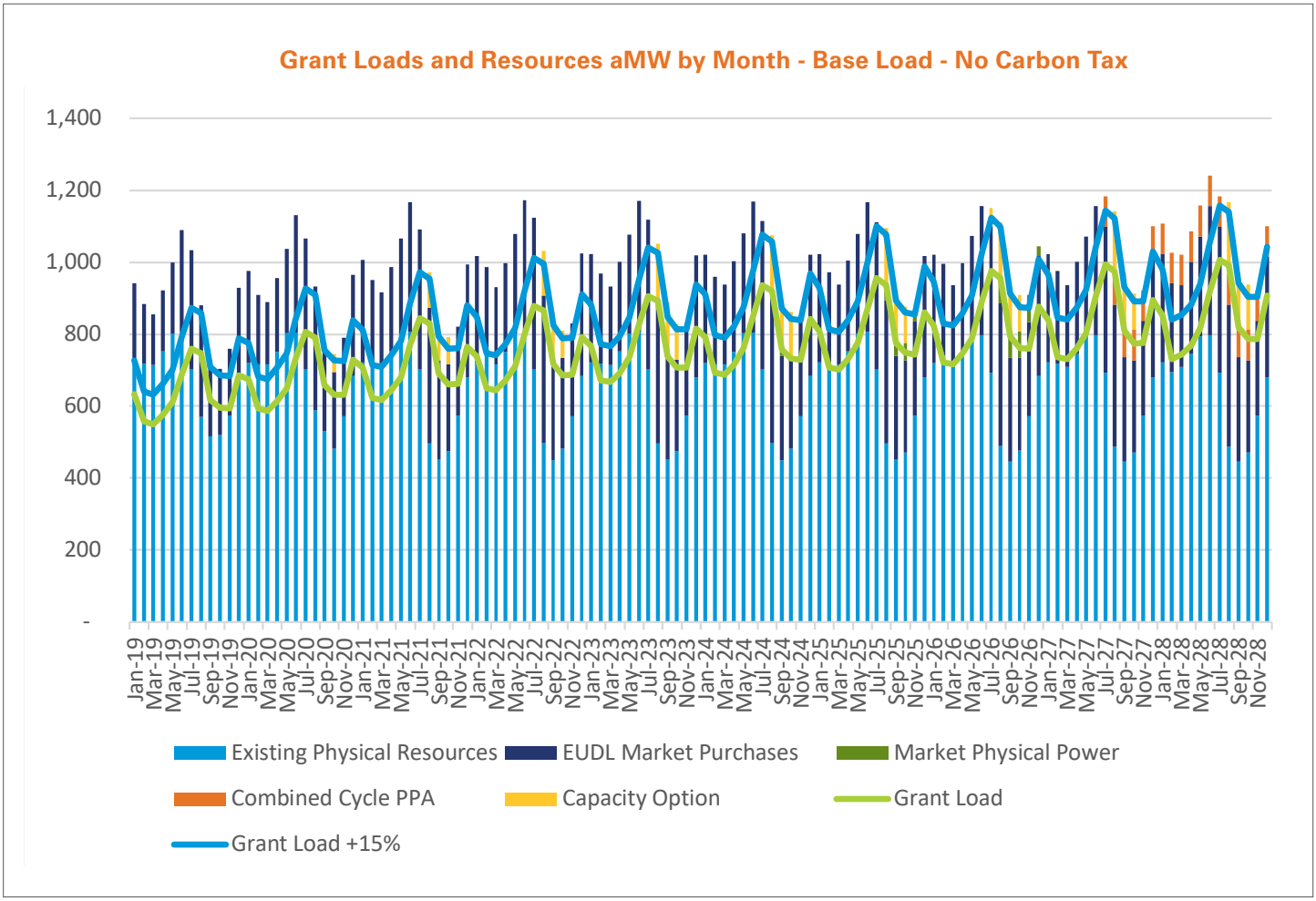
Graph 9-3



Graph 9-4



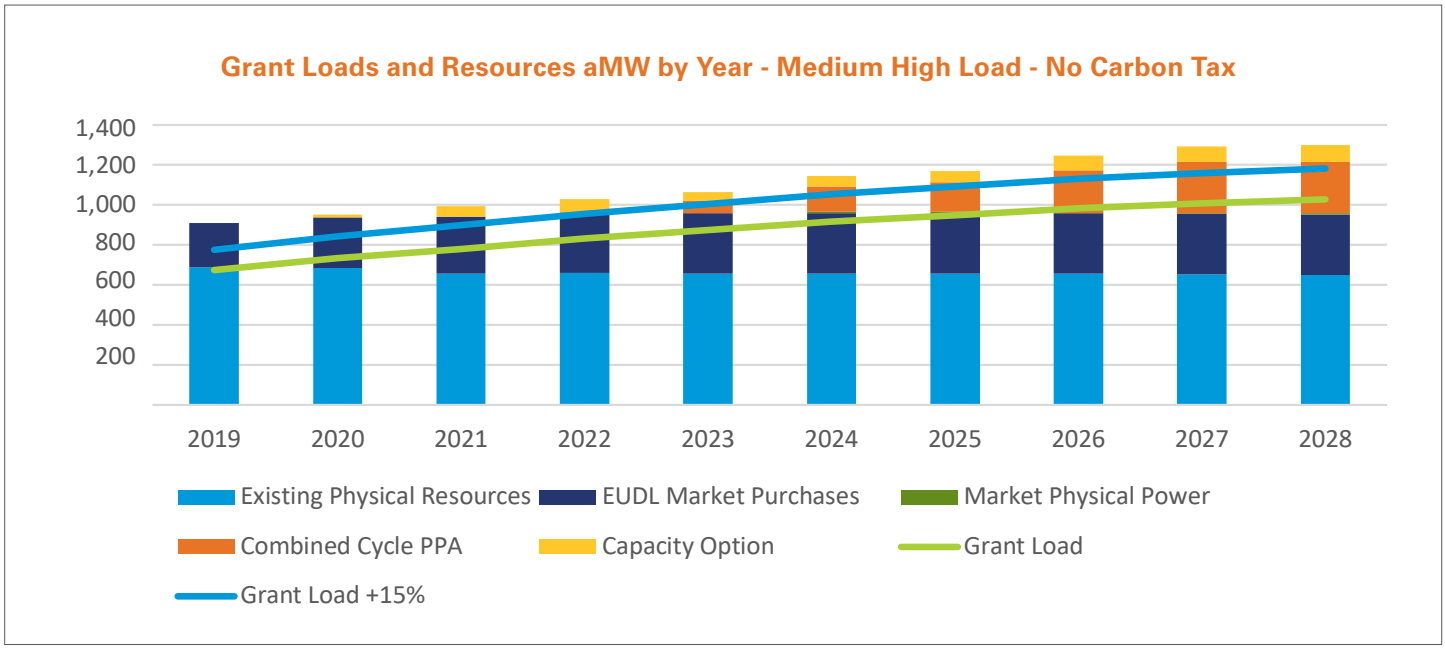
Graph 9-5



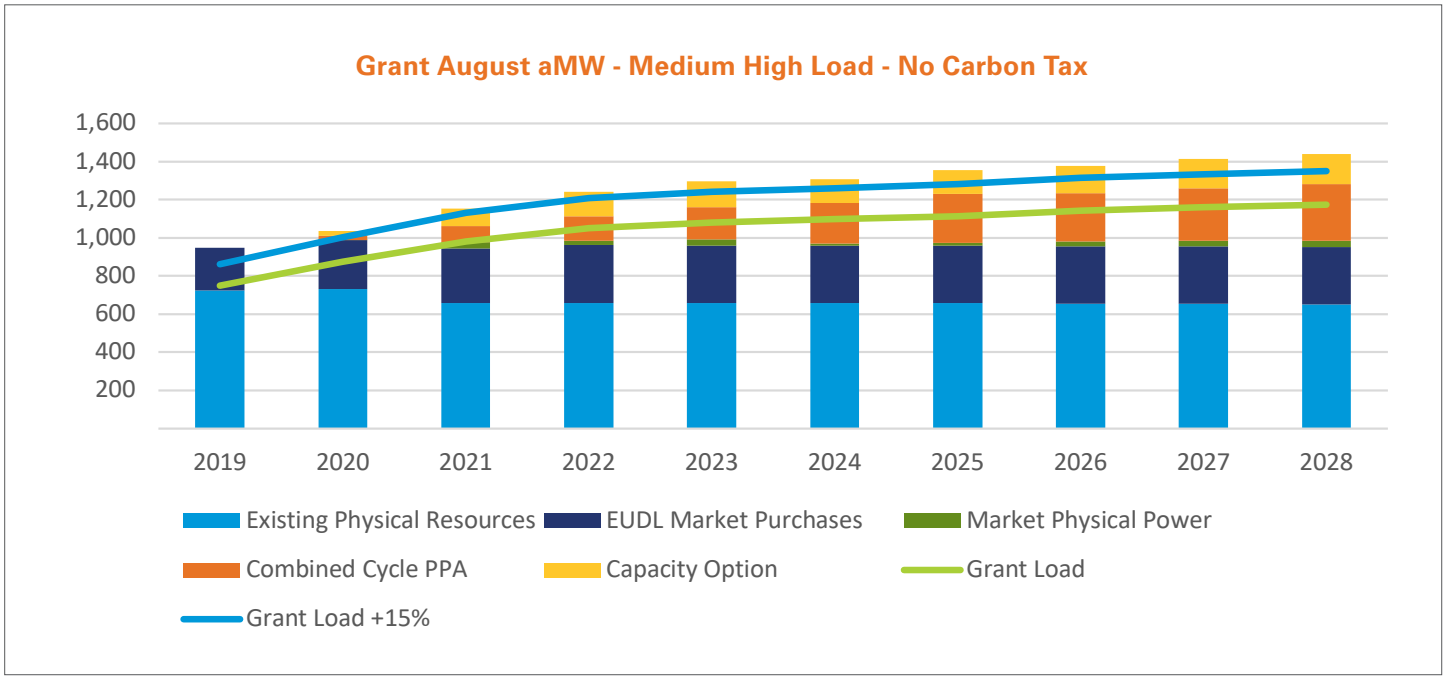
MEDIUM HIGH LOAD CASE

In the Medium High Load Case all assumptions are the same as the Base Case but with higher load growth. Under this case, the District is not able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases. Starting in 2023, the District expects to enter into a purchase power agreement for capacity on a natural gas combined cycle resource to meet its annual load requirements (Graph 9-7). The District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin. This is especially relevant during summer peaks (Graph 9-8).

Graph 9-7



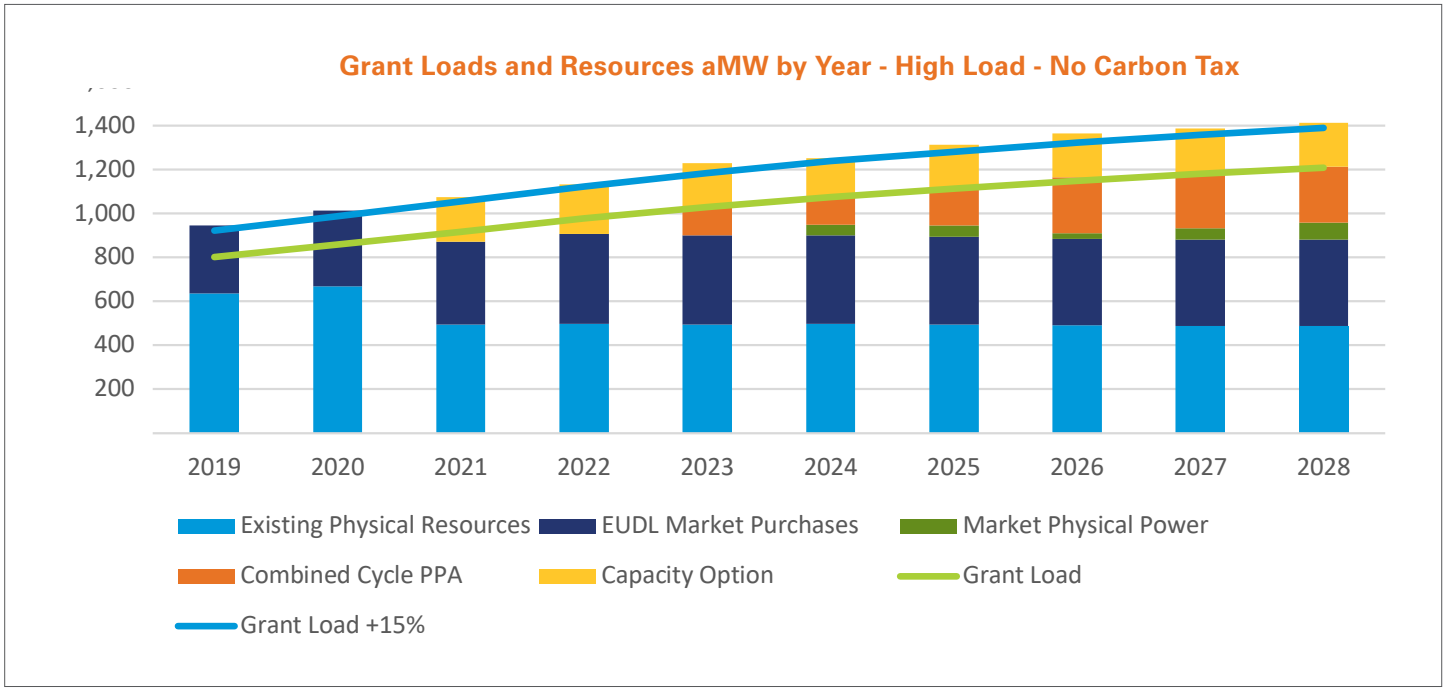
Graph 9-8



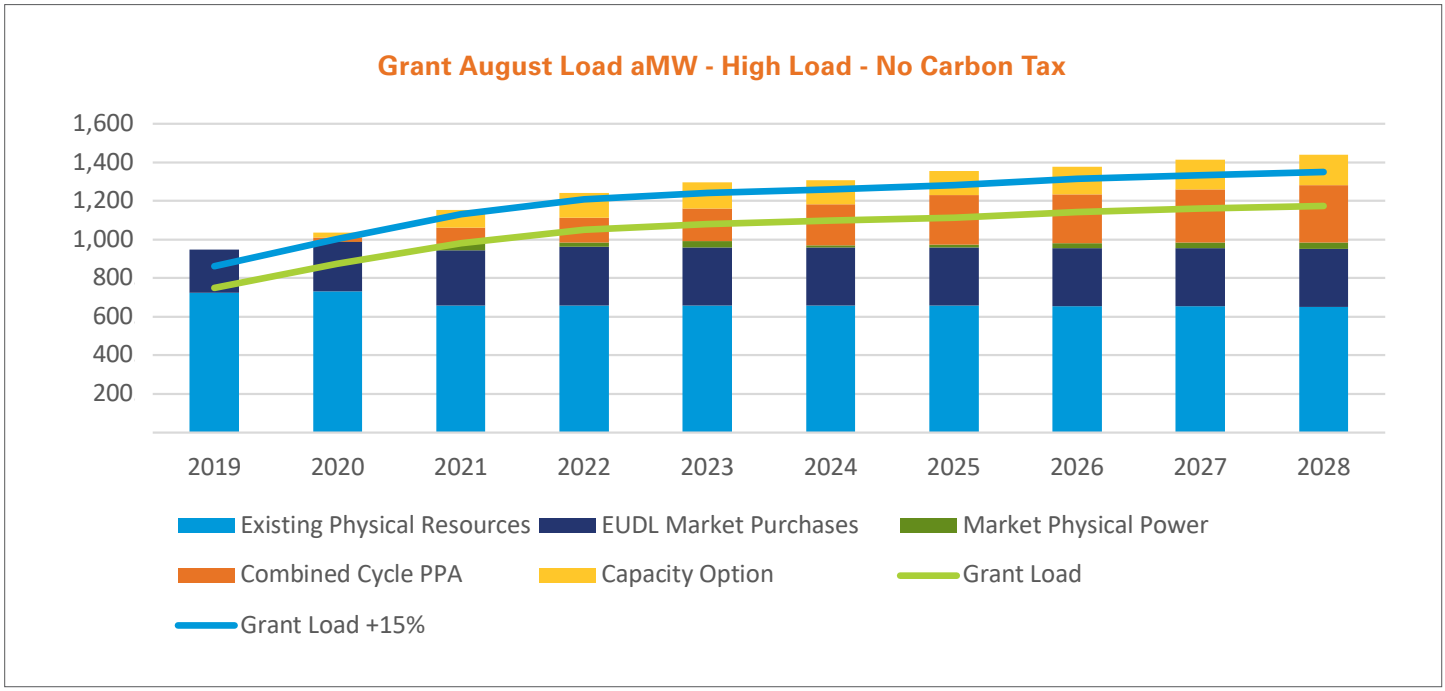
HIGH LOAD CASE

In the High Load Case all assumptions are the same as the Base Case but with the highest load growth forecast. Under this case, the District is not able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases. Starting in 2020, the District expects to enter into a purchase power agreement for capacity on a natural gas combined cycle resource to meet its annual load requirements (Graph 9-9). The District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, this is especially relevant during summer peaks (Graph 9-10).

Graph 9-9



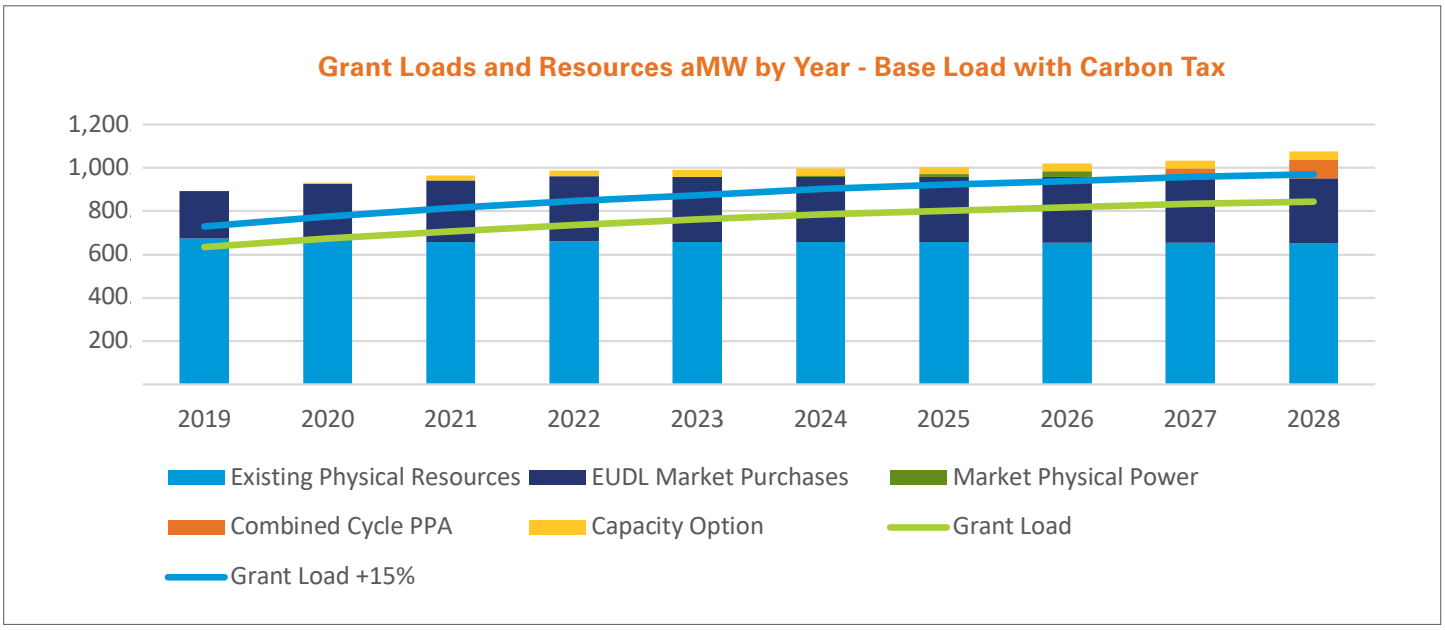
Graph 9-10



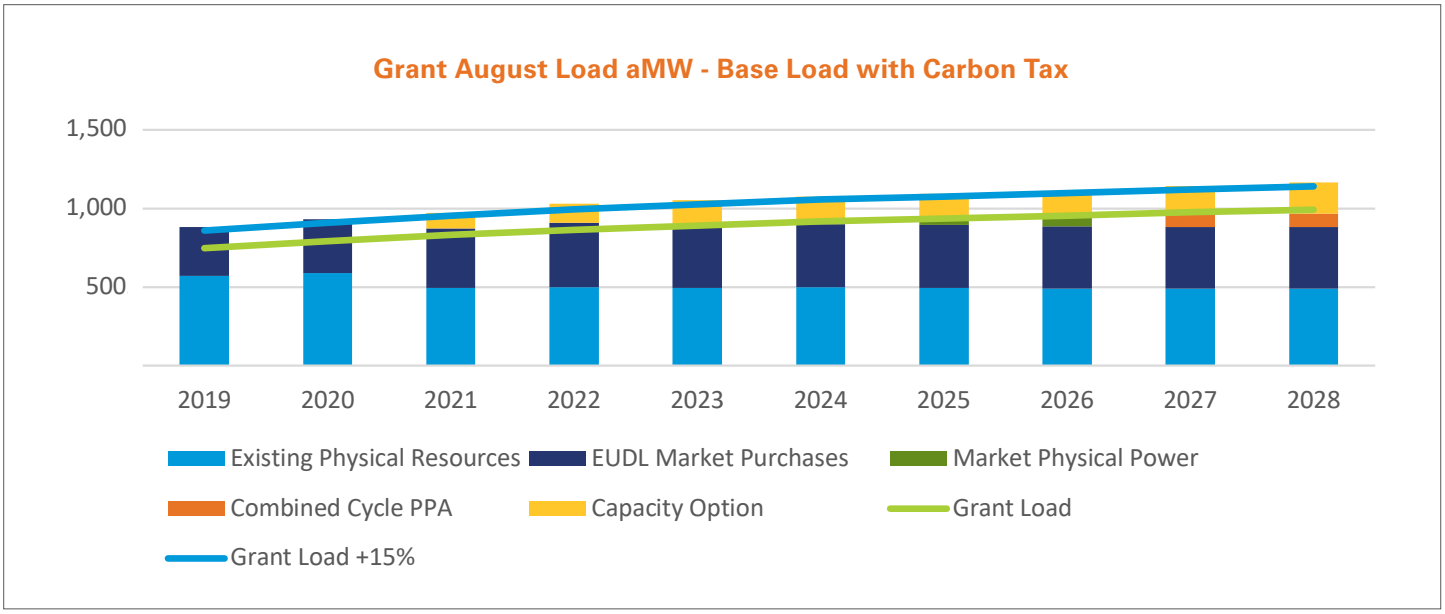
BASE LOAD WITH CARBON PRICE CASE

In the Base Load with Carbon Price Case all assumptions are the same as the Base Case but with an explicit price on carbon equal to $15/metric ton of CO2 starting in 2020 and increasing $2 each year through the 10-year planning horizon. Under this case, the District is able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases. Starting in 2027, the District expects to enter into a purchase power agreement for capacity on a natural gas combined cycle resource to meet its annual load requirements (Graph 9-11). This may come as a surprise considering the assumed $31/metric ton price on carbon in that year. However, the combined cycle continues to be the least-cost resource. The District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, this is especially relevant during summer peaks (Graph 9-12).

Graph 9-11



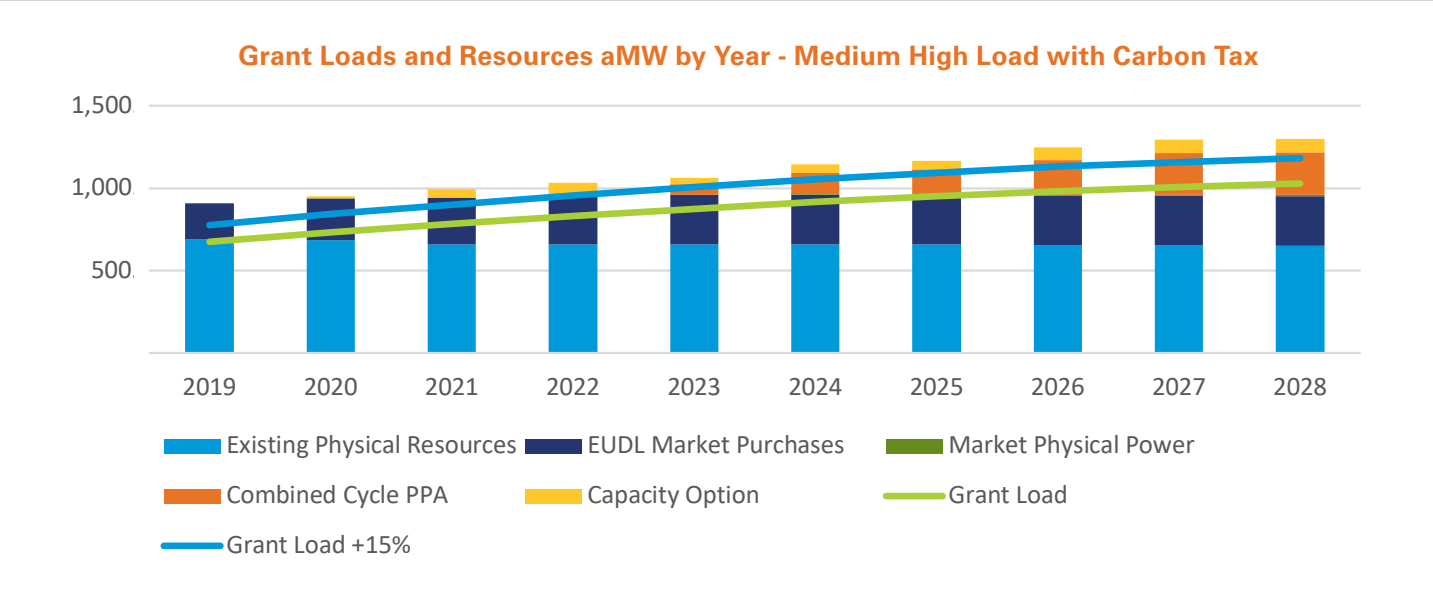
Graph 9-12



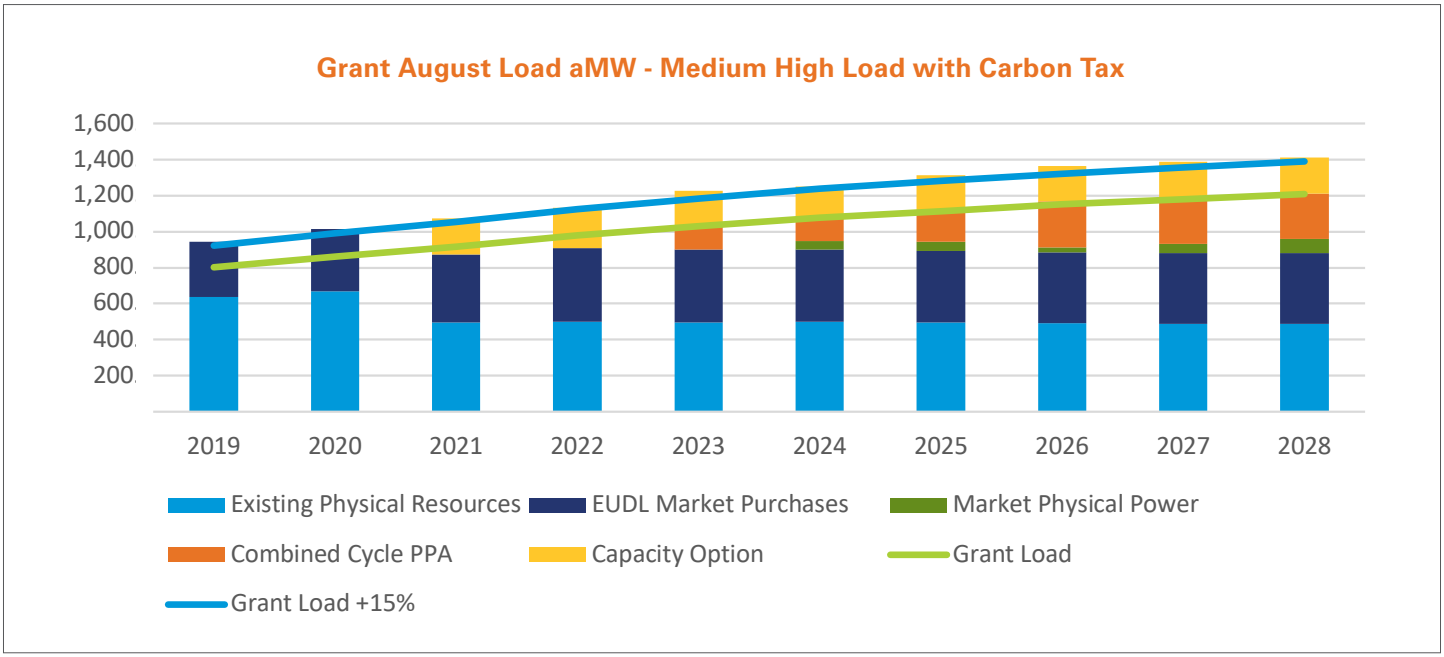
MEDIUM HIGH LOAD WITH CARBON PRICE CASE

In the Medium High Load with Carbon Price Case, all assumptions are the same as the Medium High Load Case but with an explicit price on carbon equal to $15/metric ton of CO2 starting in 2020 and increasing $2 each year through the 10-year planning horizon. Under this case, the District is able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases. Starting in 2023, the District expects to enter into a purchase power agreement for capacity on a natural gas combined cycle resource to meet its annual load requirements (Graph 9-13). The District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, this is especially relevant during summer peaks (Graph 9-14).

Graph 9-13



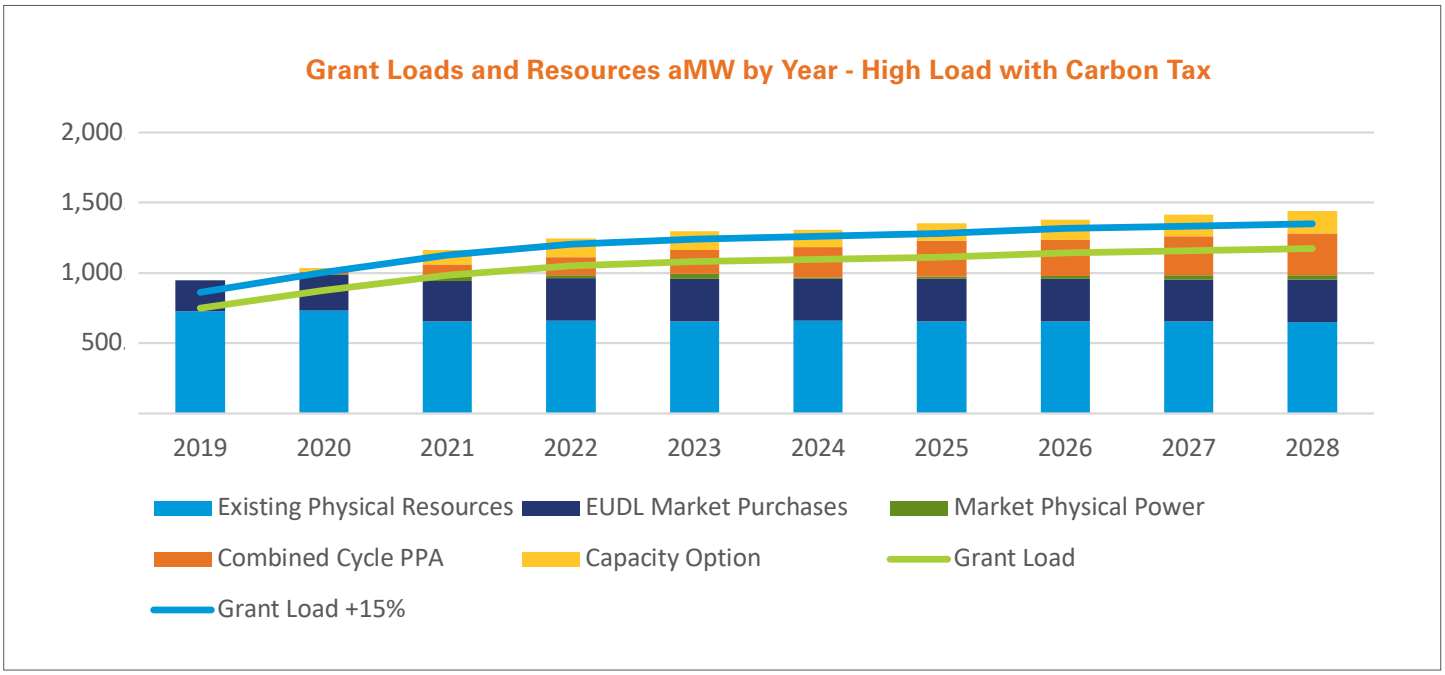
Graph 9-14



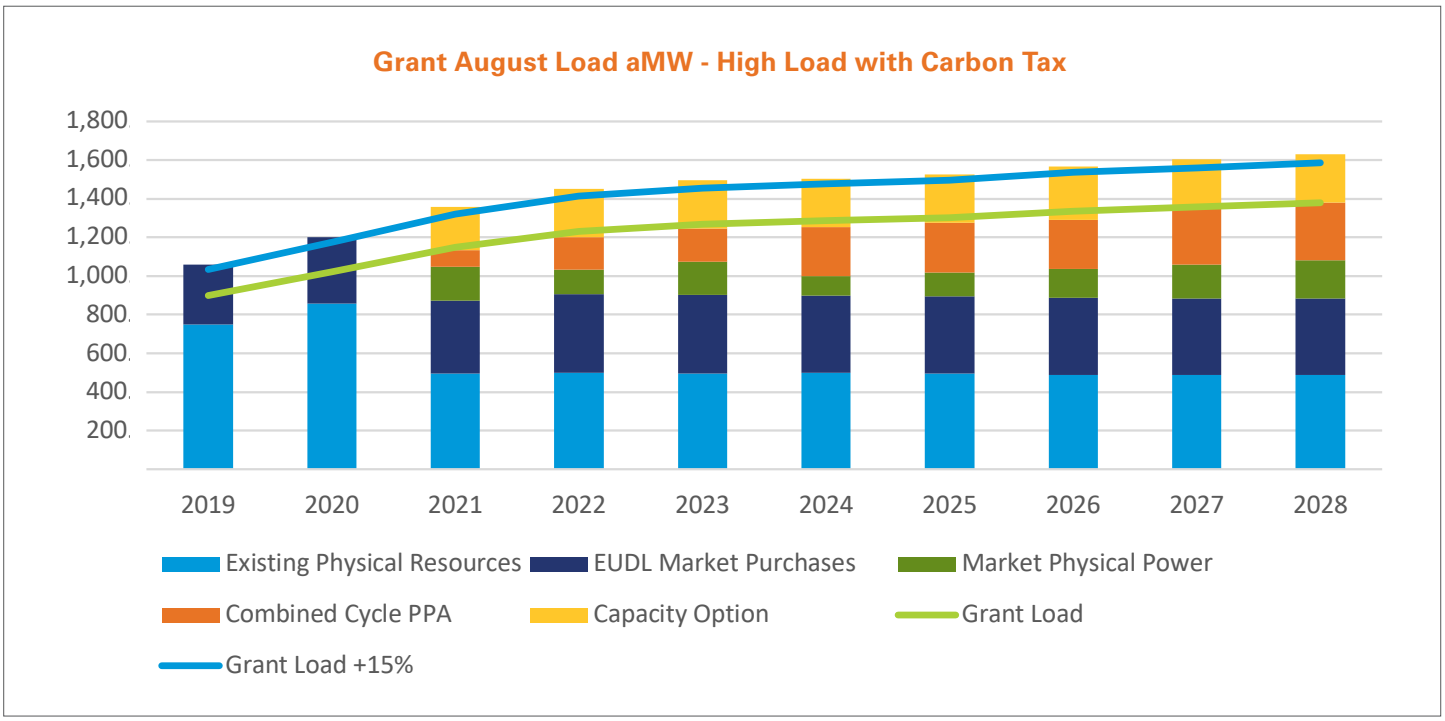
HIGH LOAD WITH CARBON PRICE CASE

In the High Load with Carbon Price Case, all assumptions are the same as the High Load Case but with an explicit price on carbon equal to $15/metric ton of CO2 starting in 2020 and increasing $2 each year through the 10-year planning horizon. Under this case, the District is able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases. Starting in 2020, the District expects to enter into a purchase power agreement for capacity on a natural gas combined cycle resource to meet its annual load requirements (Graph 9-15). The District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, this is especially relevant during summer peaks (Graph 9-16).

Graph 9-15



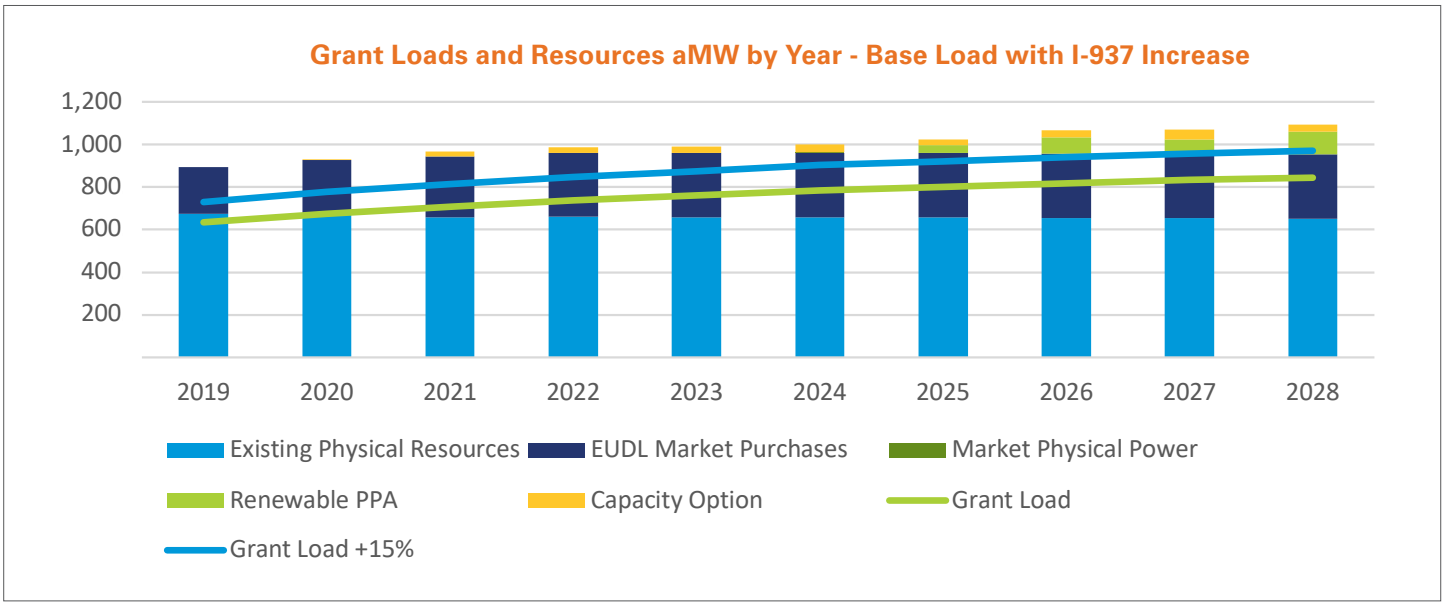
Graph 9-16



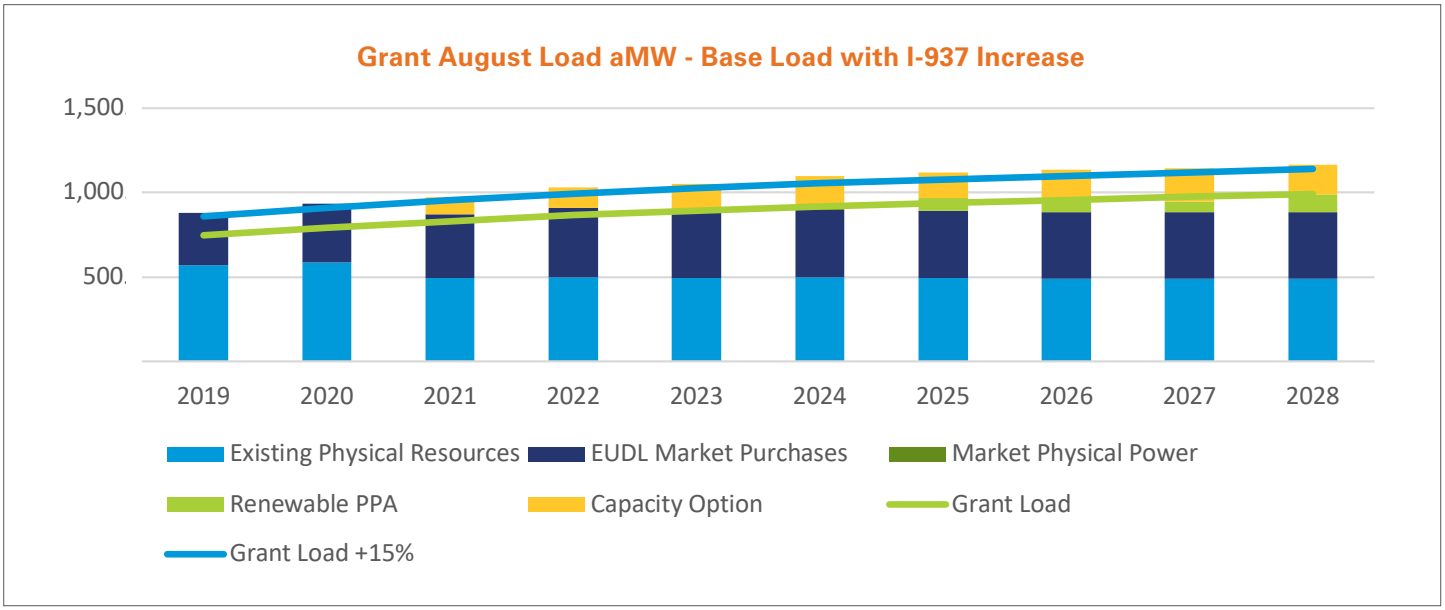
BASE LOAD WITH INCREASED RENEWABLE PORTFOLIO STANDARD CASE

In the Base Load with Increased Renewable Portfolio Standard Case, all assumptions are the same as the Base Case but with an increase in the current RPS from 15% by 2020 to 30% by 2030 (assumed to increase linearly from 2019 to 2030). While the load-resource balance does not change from the Base Case, the increase in RPS requires the District to augment generation with either purchasing eligible Renewable Energy Credits (REC) or PPAs for qualifying renewable capacity. Under this case, the District is able to meet its RPS requirements with existing RPS eligible resources through 2020. Starting in 2021 through 2024, the District will meet its additional RPS requirements with the purchase of RECs based upon anticipated market availability. Starting in 2025, the District expects to enter into a PPA for capacity from an RPS-eligible resource to meet both its annual load and increased RPS requirements because the District's needs are expected to be in excess of market supply (Graph 9-17). In this scenarios, the PPA starts two years earlier than the base case because it is the least-cost option to meet the increased RPS requirement and the District's need for capacity. However, the District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, as this remains the least-cost option (Graph 9-18).

Graph 9-17



Graph 9-18

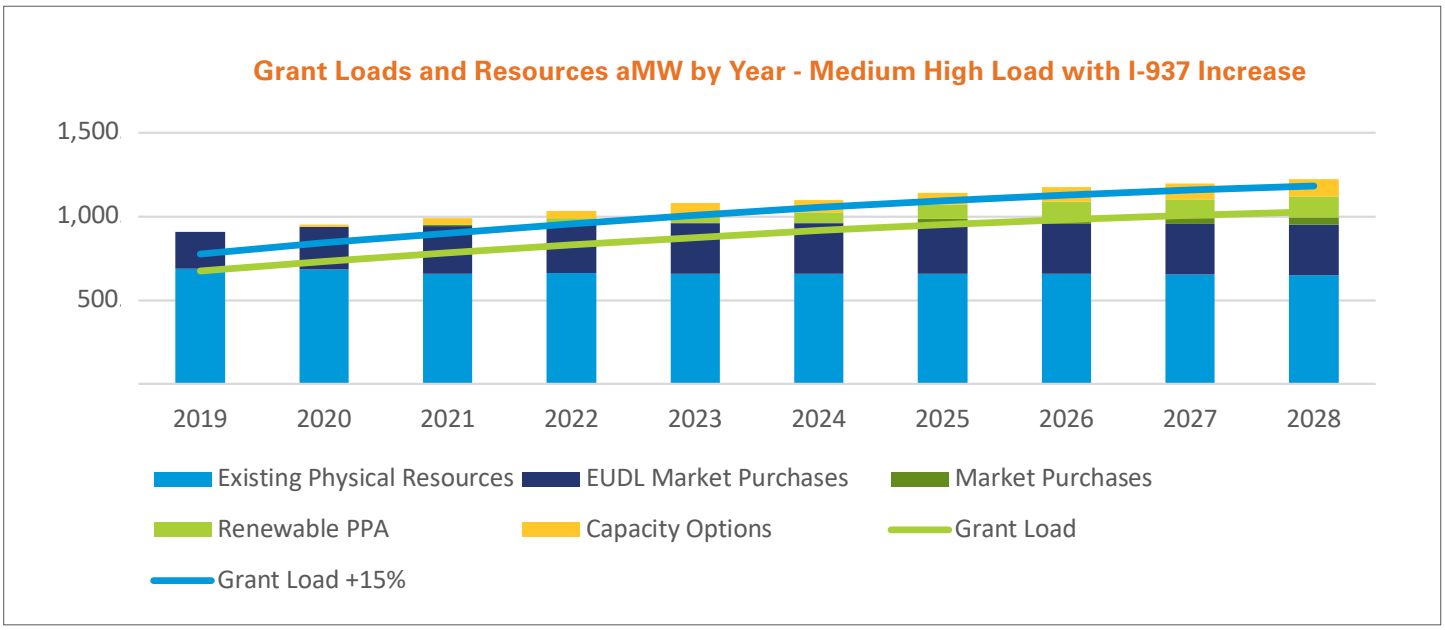


MEDIUM HIGH LOAD WITH INCREASED RENEWABLE PORTFOLIO STANDARD CASE

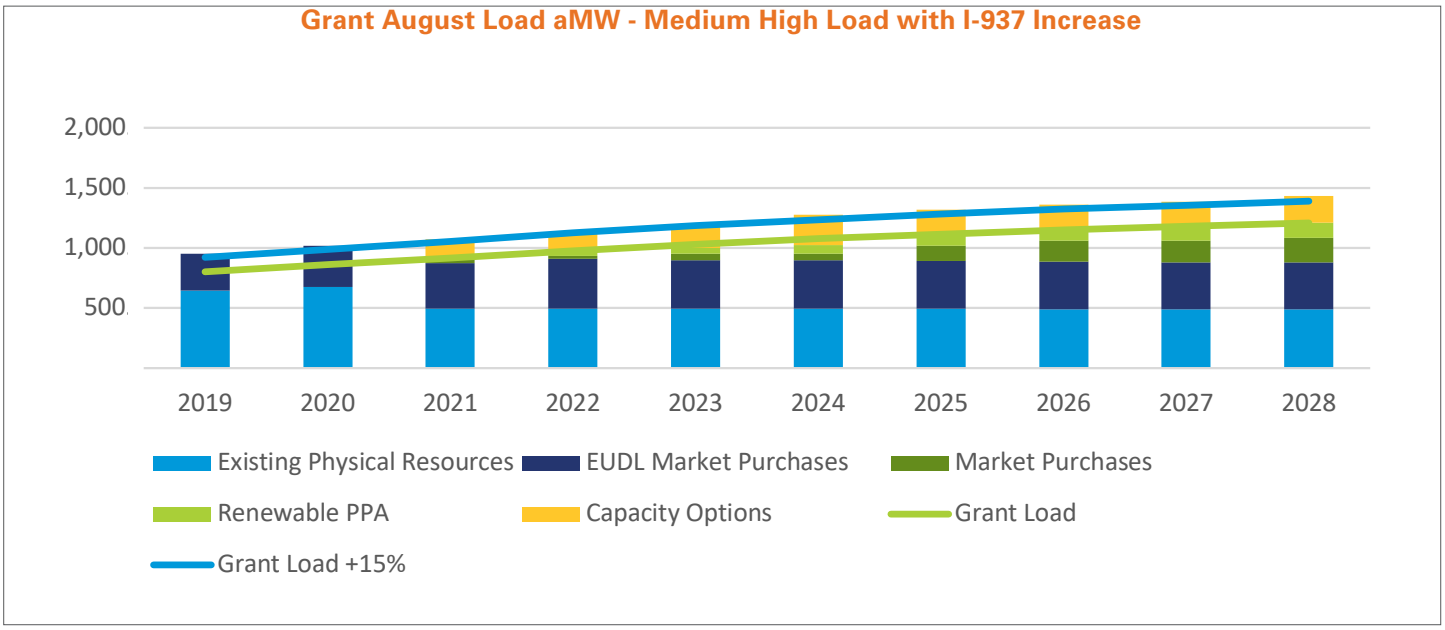
In the Medium High Load with Increased Renewable Portfolio Standard Case, all assumptions are the same as the Medium High Load Case but with an increase in the current RPS from 15% by 2020 to 30% by 2030 (assumed to increase linearly from 2019 to 2030). While the load-resource balance does not change from the Medium High Load Case, the increase in RPS requires the District to augment generation with either purchasing eligible Renewable Energy Credits (REC) or PPAs for qualifying renewable capacity. Under this case, the District is able to meet its RPS requirements with existing RPS eligible resources through 2020.

In 2021, the District will meet its additional RPS requirements with the purchase of RECs. Starting in 2022, the District expects to enter into a PPA for capacity from an RPS-eligible resource to meet both its annual load and increased RPS requirements (Graph 9-19). In this scenario, the PPA starts five years earlier than the base case because it is the least-cost option to meet the increased RPS requirement and the District's need for capacity. However, the District will still use capacity call options on a natural gas combustion turbine to meet the 15% planning margin, as this remains the least-cost option (Graph 9-20).

Graph 9-19



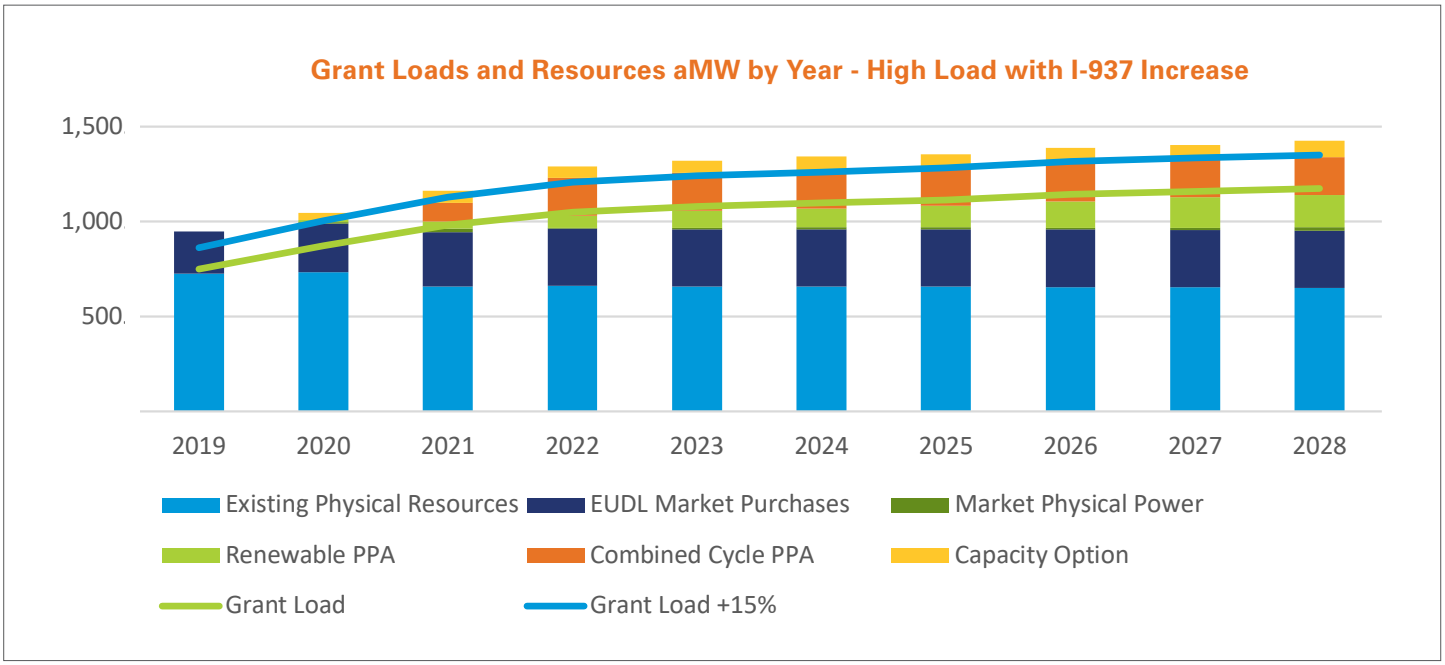
Graph 9-20



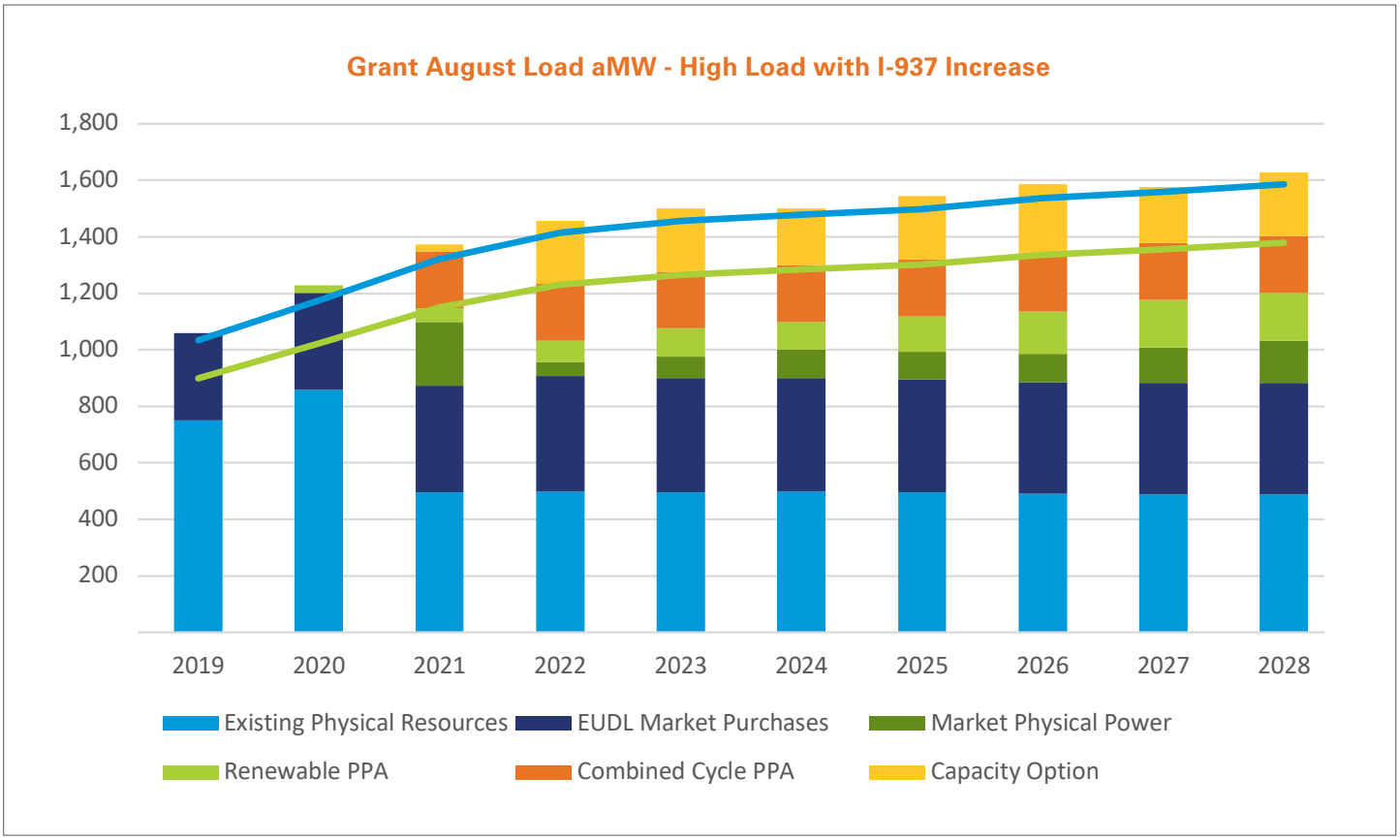
HIGH LOAD WITH INCREASED RENEWABLE PORTFOLIO STANDARD CASE

In the High Load with Increased Renewable Portfolio Standard Case, all assumptions are the same as the High Load Case but with an increase in the current RPS from 15% by 2020 to 30% by 2030 (assumed to increase linearly from 2019 to 2030). While the load-resource balance does not change from the High Load Case, the increase in RPS requires the District to augment generation with either purchasing eligible Renewable Energy Credits (REC) or PPA for qualifying renewable capacity. Under this case, the District is able to meet its RPS requirements with existing RPS eligible resources through 2019. Starting in 2020, the District expects to enter into a PPA for capacity from an RPS-eligible resource to meet both its annual load and increased RPS requirements (Graph 9-21). The renewable PPA starts seven years earlier than in the base case because it is the least-cost option to meet the increased RPS requirement and the District's need for capacity. However, the District will still use a combined cycle PPA to meet the remainder of its expected load in addition to capacity call options on a natural gas combustion turbine to meet the 15% planning margin, as this remains the least-cost option (Graph 9-22).

Graph 9-21



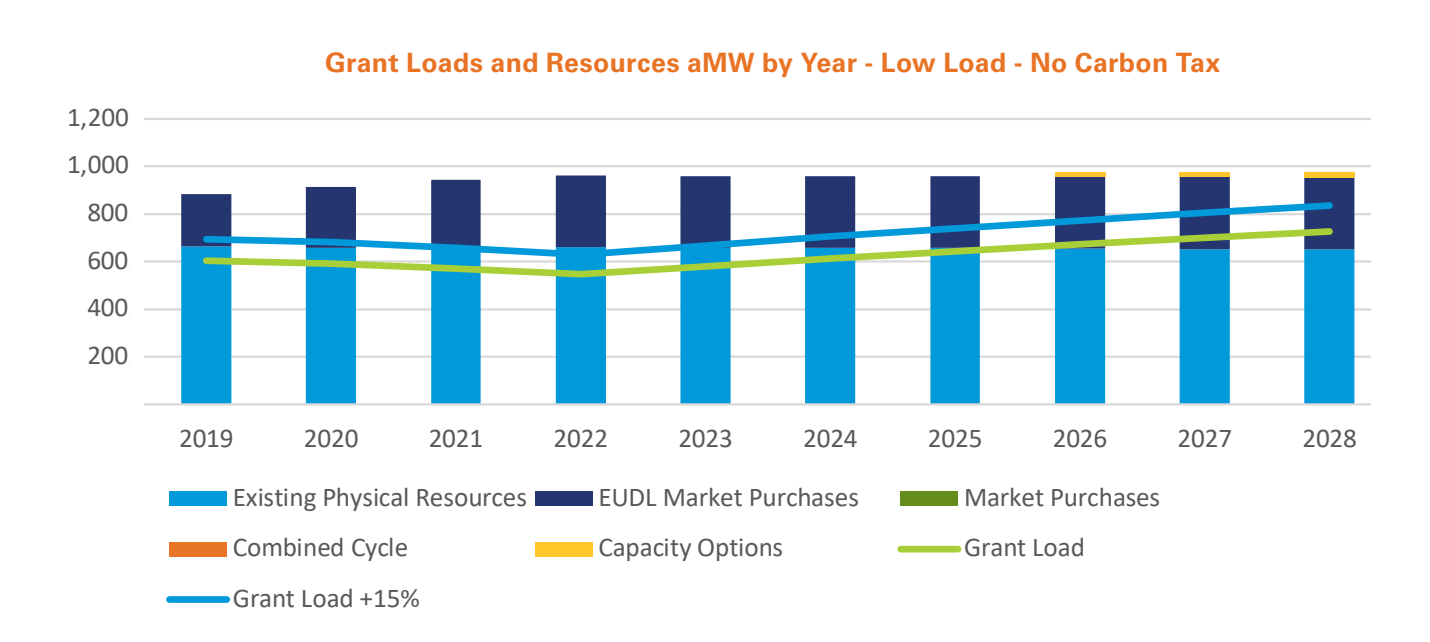
Graph 9-22


Grant August Load aMW - High Load with I-937 Increase
1,800
1,600
1,400
1,200
1,000
800
600
400
200
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Existing Physical Resources
EUDL Market Purchases
Market Physical Power
Renewable PPA
Combined Cycle PPA
Capacity Option

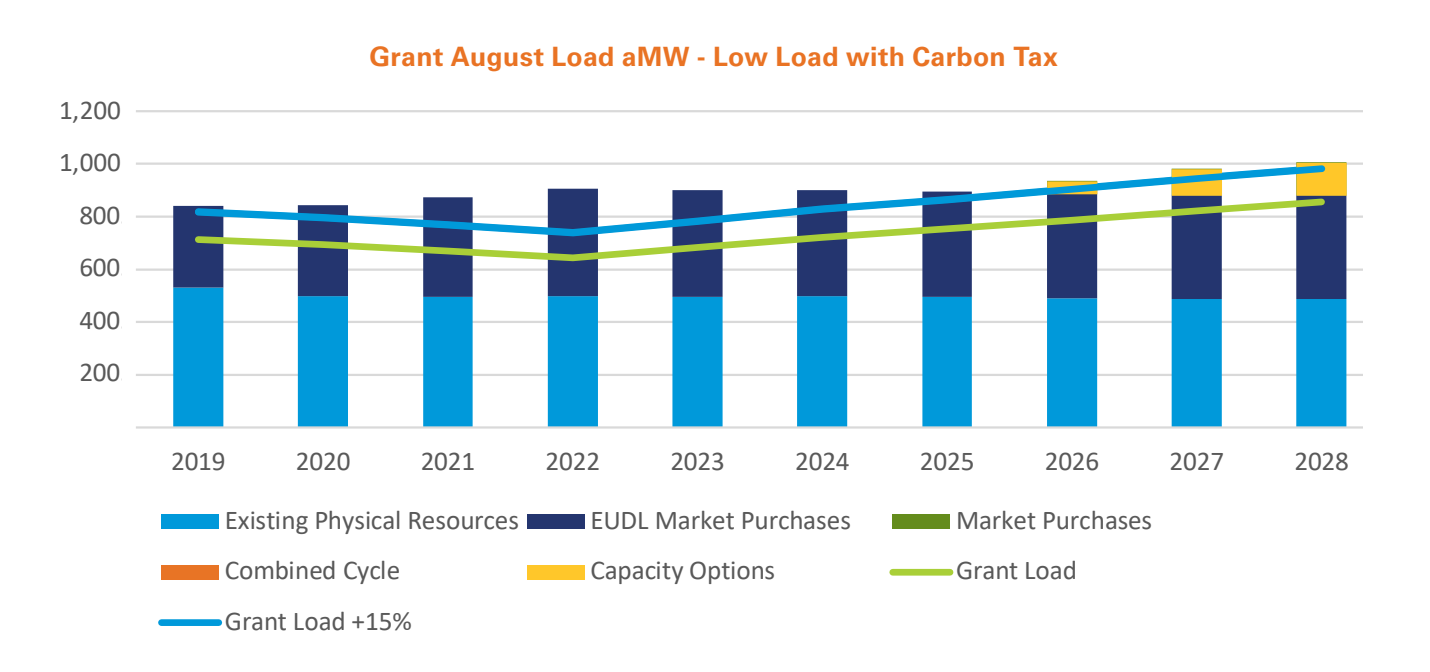
LOW LOAD CASE

In the Low Load Case, all assumptions are the same as the Base Case but with lower load growth. Under this case, the District is able to meet, on an annual basis, the expected load through the 10-year planning horizon with existing resources, EUDL, and Market Purchases (Graph 9-23). The District will still use market purchases to meet the 15% planning margin starting in 2026, this is especially relevant during summer peaks (Graph 9-24). Similar results were observed for the Low Load with Carbon Tax and Low Load with RPS Increase cases, and therefore are not highlighted in this report.

Graph 9-23



Graph 9-24



10 | CONCLUSIONS & ACTION PLAN

CONCLUSIONS

The District draws the following conclusions from the IRP analysis:

1. Based on the anticipated annual energy projections, the District has enough existing resources to meet expected load growth on an annual basis through the entire 10-year planning horizon.

2. As a result of the 15% planning margin, the District will use capacity call options to meet monthly deficits starting in 2020.

3. The District is forecasting to be seasonally capacity-deficit during late summer beginning in 2024 and winter capacity-deficit beginning in December 2028. To meet these seasonal deficiencies, the District will initially make Market Purchases starting in 2024. However, by July of 2027, the District expects to enter into a purchase power agreement for capacity from a generating resource. This decision is based upon the need to fill a large capacity requirement through the majority of the year and the assumption that this volume will be too large to fill through market trades.

4. The District will continue to meet its renewable portfolio obligations without acquiring new resources until 2025. At that time the District will acquire any expected RPS deficits with market purchases of eligible RECs.

5. The District load forecast contains significant uncertainty due to the relatively high percentage of industrial load. This load could be significantly higher or lower than the forecast based on a number of factors, many of which are outside the District's control. The District has reviewed the potential risks associated with the load uncertainty, and will continue monitoring the load and expectations of this customer segment.

6. The District will need to stay abreast of changes in the utility industry affecting the District's planning processes.

ACTION PLAN

The District should take the following actions based on the results of this IRP.

1. Monitor opportunities to procure low-cost, long-term generating resources (particularly resources that qualify for I-937 compliance), with an eye towards opportunities priced better than new-build costs. This includes the possible use of the Bonneville Power Administration (BPA) as a source of market purchases as well as preference customer status opportunities after 2028.

2. Continue to implement and achieve cost-effective conservation available within the county as indicated in the District's Conservation Potential Assessment.

3. Continue to enhance the capacity planning process and standards to ensure the District adequately plans to reliably meet both the energy and peaking needs of the District's electric system. The District's capacity planning process and standard should conform to the evolution in power planning for the Pacific Northwest. Therefore, the District should participate in and monitor regional forums related to resource planning.

4. Evaluate the relative value of the Shell Energy Exchange deal with a goal of determining whether to extend or replace the deal at the end of the five-year term. This effort should address areas where the arrangement could be improved for the benefit of the District and how the arrangement might work with the evolving Northwest energy markets.

5. Continue to refine and improve the retail energy load forecasts, with an emphasis on monitoring changes from the large industrial customers, given their ability to change the District load and resource balance. The District's ability to monitor and forecast resource requirements is being enhanced with the installation of the Advanced Metering Program.

6. Evaluate the opportunities presented by the expansion of the Northwest EIM and the possible growth of the California Independent System Operator into the Northwest. The District should work to identify the best strategy (from a cost, opportunity and risk basis) to interact with this evolving market.

7. Continue to participate in regional utility groups that monitor and influence legislation that could affect the District's ratepayers.

APPENDIX 1:
RESOLVE MODEL

11. RESOLVE Model Description

1 RESOLVE Model Description

1.1 RESOLVE Model

1.1.1 OVERVIEW

RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. At the same time, it means that emerging technologies that could play a role in a low-carbon future for the Northwest—for instance, small modular nuclear reactors—are not evaluated within this study. This modeling choice is not meant to suggest that such emerging technologies should not have a role in

meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study. The full range of resource options considered by RESOLVE in this study is shown in Table 2-1.

Table 2-1. Resource options considered in RESOLVE

Resource Option	Examples of Available Resources	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines • Repowered CCGTs	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Geothermal • Hydro upgrades • Solar PV • Wind •	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load • Hydro resources have full up and downward flexibility to balance load.
Energy Storage	• Batteries (>1 hr) • Pumped Storage (>12 hr)	• Stores excess energy for later dispatch • Contributes to meeting minimum generation and ramping constraints
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Interruptible tariff (ag) • DLC: space & water heating (res)	• Contributes to planning reserve margin needs

1.1.2 OPERATIONAL SIMULATION

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify traditional unit commitment problem where possible while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

- **Hourly chronological simulation:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
- **Aggregated generation classes:** rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas CCGT, gas CT). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
- **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class' operations.
- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: the Core Northwest region and five external areas that represent the loads and resources of utilities throughout the rest of the Western Interconnection.
- **Co-optimization of energy and ancillary services:** RESOLVE dispatches generation to meet load across the Western Interconnection while simultaneous reserving flexible capacity within the Primary Zone to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.
- **Smart sampling of days:** whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the WECC system for 41 independent days. Load, wind, and solar profiles for these 41 days, sampled from the historical meteorological record of the period 2007-2009, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete

distributions of potential conditions; daily hydro conditions are sampled separately from low (2001), average (2005), and high (2011) hydro years to provide a complete distribution of potential hydro conditions.[15] This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the 41 days.

+ **Hydro dispatch informed by historical operations:** RESOLVE captures the inherent limitations of the generation capability of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: (1) daily energy budgets, which limit the amount of hydro generation in a day;[16] (2) maximum and minimum hydro generation levels, which constrain the hourly hydro generation; and (3) maximum multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change its output across periods from one to four hours. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. The derivation of these constraints from actual hourly operations makes this representation of hydro operations conservative with respect to the amount of potential flexibility in the resource.

1.1.3 ADDITIONAL CONSTRAINTS

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

[15] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions.

[16] Sometimes hydro operators can shift hydro energy from day to day: for example, if hydro operators know that tomorrow will be a peak day, they can save some hydro energy today and use them tomorrow to meet the system need. This flexibility can help integrating renewable into the system and it is going to be more and more valuable as the % of system renewable penetration increases. To capture this flexibility, model allows up to 5% of the hydro energy in each day to be shifted around within two months.

- **Planning reserve margin:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet 1-in-2 system peak plus additional 15% of planning reserve margin (PRM) requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours.
- **Renewables Portfolio Standard (RPS) requirement:** RPS requirements have become the most common policy mechanism in the United States to encourage renewable development. RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year.
- **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators.
- **Resource potential limitations:** Many potential new resources are limited in their potential for new development. This is particularly true for renewable resources such as wind and solar. RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio, imposing practical limitations on the amount of any one type of resource that may be developed.

RESOLVE considers each of these constraints simultaneously, selecting the combination of new generation resources that adheres to these constraints while minimizing the sum of investment and operational costs.

1.1.4 KEY MODEL OUTPUTS

RESOLVE produced a large amount of results from technology level unit commitment decisions to total GHG emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

- **Total revenue requirement ($/yr):** The total revenue requirement reports the total costs incurred by utilities in the study footprint (the combination of Washington and Oregon) to provide service to its customers. This study focuses on the relative differences in revenue requirement among scenarios, generally measuring changes in the revenue requirement relative to the Reference Case. The cost impacts for each scenario comprise changes in fixed costs (capital & fixed O&M costs for new generation resources, incremental energy efficiency, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs, fuel costs, costs of market purchases and revenues from surplus sales).
- **Greenhouse gas emissions (MMTCO2e):** This result summarizes the total annual GHG emission in the system with imports and exports adjustments. The GHG emission is one of the most important metrics for the studies. By comparing the GHG emission and total resource costs between different policy scenarios, we can conclude the relative effectiveness of policies in GHG reduction.
- **Resource additions for each period (MW):** The selected investment summarizes the cumulative new generation capacity investments by resources types. It provides an overview of what kinds of generation are built and the timing of the investments.
- **Annual generation by resource type (aMW):** Energy balance shows the annual system load and energy produced by each resource type at yearly intervals. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of resources are dispatched more? How do the dispatch behaviors change over the years? And how do curtailment, imports, and exports vary year by year?

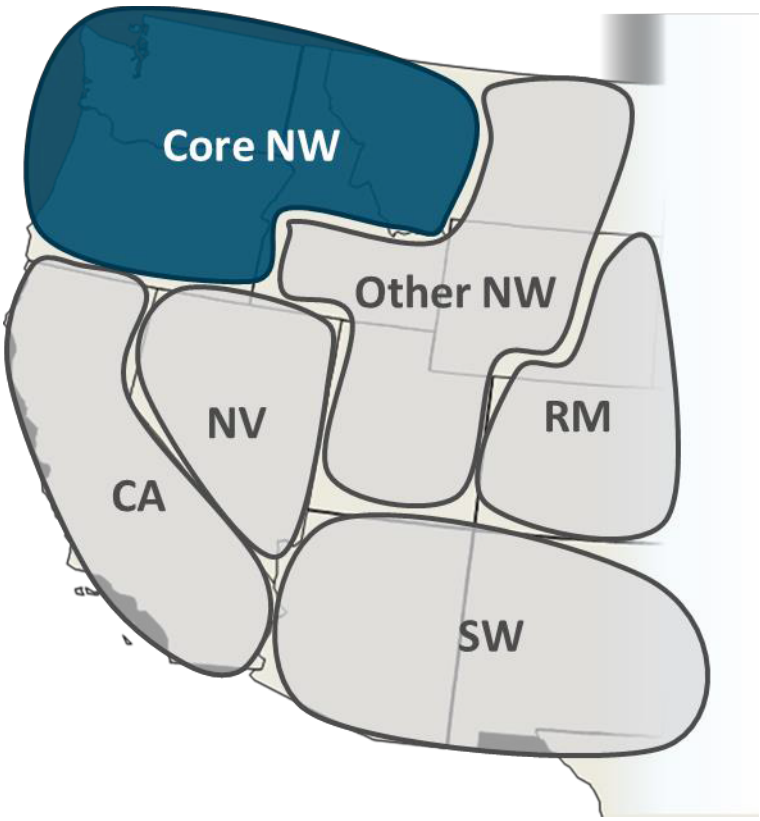
- **Renewable curtailment (aMW):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.
- **Wholesale market prices ($/MWh):** outputs from RESOLVE can be used to estimate wholesale market prices on an hourly basis (or during the standard HLH and LLH trading periods). As an optimization model, RESOLVE produces "shadow prices" in each hour that represent the marginal cost of generation given all the resources available at the time; these marginal costs serve as a proxy for wholesale market prices.
- **Average greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case).

1.2 Study Footprint

This report analyzes the different policy mechanisms that could be used to achieve GHG reduction goals in predominantly Washington and Oregon, with a small portion of Idaho and Montana loads that fall in BPA and AVA control areas. In this respect, the footprint of this study differs from the Northwest Regional Planning Area established by the Pacific Northwest Electric Power Planning and Conservation Act and used by regional planning entities in much of their work. This narrower study footprint representing only a portion of what is traditionally considered the Pacific Northwest is motivated by the desire to focus on the electric power sector within the states of Oregon and Washington, where policy discussions

surrounding potential measures to facilitate decarbonization are considerably more advanced than elsewhere in the Pacific Northwest. Figure 2-1 shows a diagram summarizing the study footprint.

Figure 2-1. Northwest low carbon grid study footprint



This study focuses on the ratepayers of the District in addition to the Core Northwest region shown as the "Primary Zone"—the zone for which RESOLVE makes generation investment decisions. For the purposes of simulating west-wide operations, the remaining balancing authorities outside of the Core Northwest are grouped into five additional "Secondary Zones." Investments in these zones are not optimized; the trajectory of new build for the external regions is based on regional capacity needs to meet PRM targets, as well as renewable needs to comply with existing RPS policies in those regions.

Table 2-2. Balancing authorities included in each study region.

Category	Study Zone	Constituent Balancing Authorities
Primary Zone	Core Northwest	• Avista Corporation (AVA) • Bonneville Power Administration (BPA) • Chelan Public Utilities District (CHPD) • Douglas Public Utilities District (DOPD) • Grant County Public Utilities District (GCPD) • Pacificorp West (PACW) • Portland General Electric (PGE) • Puget Sound Energy (PSE) • Seattle City Light (SCL) • Tacoma Power (TPWR)
Secondary Zones	Other Northwest	• Idaho Power Company (IPC) • NorthWestern Energy (NWMT) • Pacificorp East (PACE) • WAPA – Upper Wyoming (WAUW)
	California	• Balancing Authority of Northern California (BANC) • California Independent System Operator (CAISO) • Imperial Irrigation District (IID) • Los Angeles Department of Water and Power (LADWP) • Turlock Irrigation District (TIDC)
	Nevada	• Nevada Power Company (NEVP) • Sierra Pacific Power (SPP)
	Rocky Mountains	• Public Service Company of Colorado (PSC) • WAPA – Colorado-Missouri (WACM)
	Southwest	• Arizona Public Service Company (APS) • El Paso Electric Co (EPE) • Public Service Company of New Mexico (PNM) • Salt River Project (SRP) • Tucson Electric Power (TEP) • WAPA – Lower Colorado
Excluded		• Alberta Electric System Operator (AESO) • British Columbia Transmission Company (BCTC) • CFE (CFE)

Alberta and British Columbia and their interactions with the rest of the Western Interconnection are not modeled in the scenarios due to lack of publicly available data. While its interactions with the Canadian provinces is an important characteristic of the Northwest electricity system, the omission of this portion of the Western Interconnection is not expected to fundamentally alter the general dynamics or overall findings of this analysis.

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APPENDIX 2:
PUBLIC GENERATING POOL SCENARIO ANALYSIS

Public Generating Pool

Pacific Northwest Low Carbon Scenario Analysis
June 2018

PGP Study Observations

- **THE DEFINITION OF 100% IS IMPORTANT.** There are many ways to define a 100% standard for the electric sector. The reliability and cost impacts between the two are quite different.

  — Absolute Zero Carbon: The E3 analysis follows the definitions used in HB 2995 and SB 6253 which set a regulatory standard of zero carbon used to serve load in Washington[i]:.
  — Net Zero Carbon: The more prevalent measurement used in RPS standards and for corporate "100% renewable" or "carbon-free" goals is for renewable or zero-carbon energy netted over a year to be equal to or greater than energy used. This definition recognizes that during some hours load is served with thermal content energy but is offset by additional generation of renewable or zero carbon energy in other hours[ii].

HB 2995 AND SB 6253 DEFINITION	STANDARD RPS/CARBON-FREE DEFINITION
Zero carbon content energy must be used to serve load in Washington in every hour	Renewable or zero-carbon generation or credits >= load as measured over a year

- **THERE ARE CHALLENGES IN ACHIEVING POLICIES REDUCING CARBON BEYOND 80% BELOW 1990 LEVELS**. RESOLVE modeling shows that as the policy objectives move beyond the 80% below 1990 levels[iii], cost and reliability challenges increase exponentially. New technology, that does not exist today, would be needed to reliably meet load.

- **THE CHALLENGES INCREASE AS ELECTRIC SECTOR LOAD INCREASES**. Most economy-wide decarbonization studies highlight electrification of transportation and building (the highest carbon producing sectors in Washington) as key to producing meaningful carbon reductions; some suggest the percentage of energy demand served by electricity could double[iv]. Additional load will increase reliability challenges and cost to the electric sector, which could negatively impact the ability to electrify other sectors[v].

- **FEASIBLITY OF GENERATION AND TRANSMISSION BUILD IS UNCERTAIN**. New generating resources require land and, depending on location, transmission. The acreage required for new renewables increases significantly when the goal expands beyond 90% below 1990 levels. The RESOLVE model solutions for the 100% cases rely on wind and solar resources, the bulk of which require east-west transmission construction.

- **ELECTRIC SYSTEM RELIABILITY IS UNCERTAIN IN SCENARIOS THAT LIMIT DISPATCHABLE THERMAL CAPACITY**: The RESOLVE model provides a high-level comparison of various scenarios and sensitivities to inform which options warrant detailed analysis. It is not designed to comprehensively analyze feasibility or reliability of certain scenarios. Additional reliability and feasibility study is needed to evaluate these scenarios.

- **BIOGAS QUANTITIES ARE LIMITED AND UNCERTAIN**. Biogas, by its nature, is finite and may have significant implications for land-use and food production. Current available quantities in the Northwest are low, especially for sources near existing infrastructure. Heavy reliance on biogas will require additional gas transportation infrastructure. The ability to produce and transport additional sources of biogas at a reasonable cost is not fully known.

- **BIOGAS IN TRANSPORTATION PROVIDES TWICE THE CARBON REDUCTION BENEFIT TO USE TO PRODUCE ELECTRICITY.** Liquid fuels used in transportation are significantly more carbon-intensive than natural gas, and internal combustion engines are much less fuel efficient than natural gas power plants. Limited supplies of biogas may be better directed at reducing transportation emissions.

PGP Interests

Washington state carbon-reduction policies are balanced and recognize:

- All four pillars of decarbonization are necessary: energy efficiency, electrification of transportation and other uses, low carbon electricity and low carbon fuels.
- Transportation and buildings/industry are the #1 and #2 sources of carbon in the Washington economy.
- Policy objectives in the electric sector are considered in the context of an economy-wide strategy for decarbonization.
- The price of electricity impacts the ability to electrify other sectors.

Electric sector carbon-reduction policies:

- Focus on efficiently reducing carbon at the least-cost to customers
- Regulate carbon directly and uniformly rather than require or limit specific technologies
- Preserve and enhance the value of existing carbon-free resources
- Require reliability of the electric system
- Support electrification of transportation with cross-sector consideration of funding and analysis
- Ensure regulatory approaches do not limit Washington resources' ability to engage in Western markets

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[i] Elimination of all carbon from the electric sector has not been proven to be reliable and is estimated to cost $18.4 billion/year. Other studies conducted in California have comparable findings of high cost relative to low carbon solutions when eliminating *all* carbon from the electric system. See Slide 12 SMUD IRP Preliminary Results and pages 39-40 of CEC Deep Decarbonization in a High Renewables Future, June 2018.

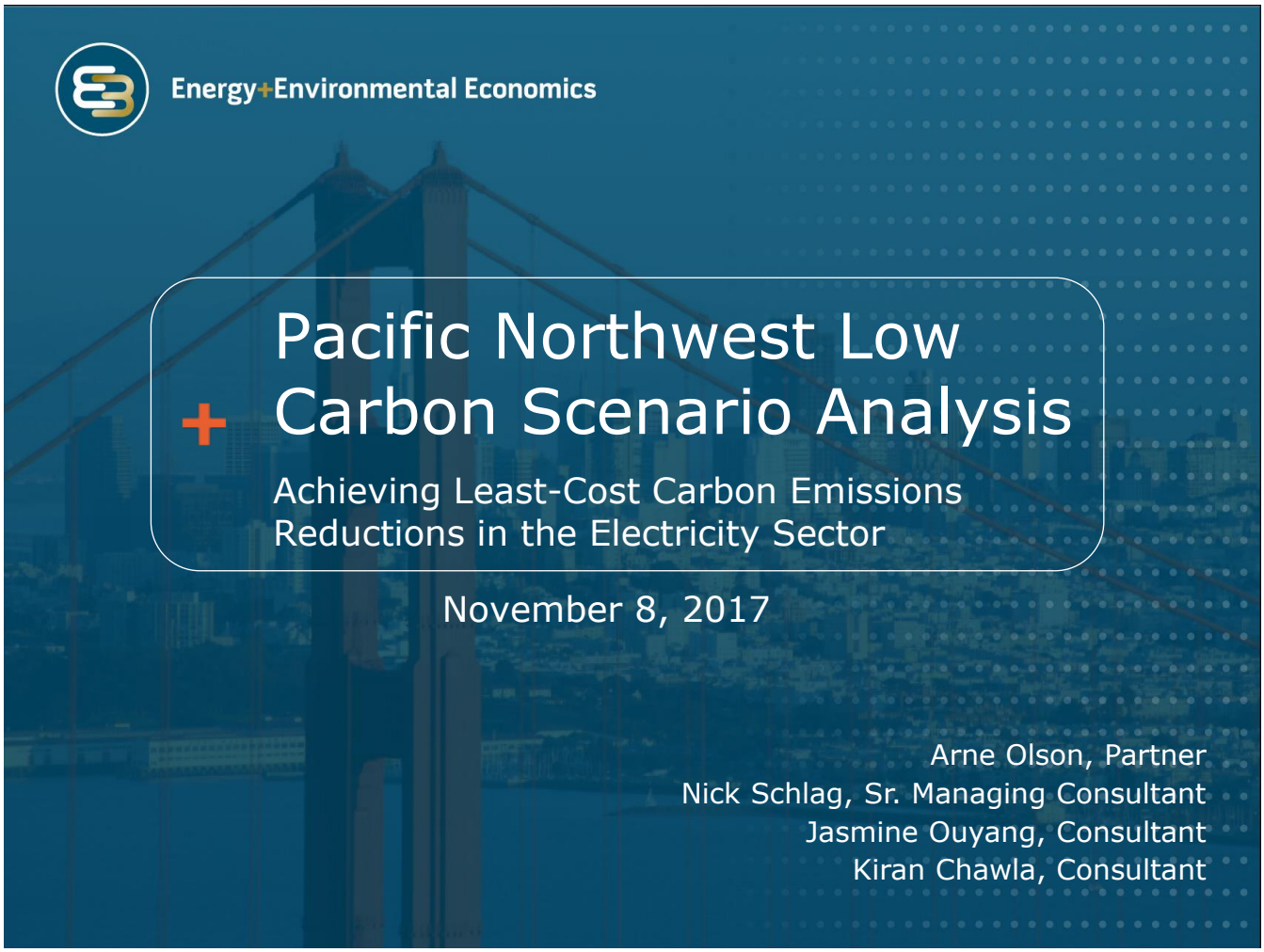
[ii] The 2017 Pacific Northwest Low Carbon Scenario Analysis demonstrated that many scenarios, including 80% below 1990 levels, could achieve 100% effective net zero carbon while maintaining reliability.

[iii] Or when the Washington and Oregon electric sector allowable carbon budget drops below 6 million metric tons of carbon.

[iv] PGE Pathways to Deep Decarbonization, June 2018 presentation to Oregon Global Warming Commission, slide 8.

[v] The 2017 Pacific Northwest Low Carbon Scenario Analysis included a sensitivity analysis that increased electric vehicle adoption by 3.5 million cars in 2050 while maintaining 80% below 1990 levels. The study estimated an increase in electric sector load of 2,200 aMW and costs of $1.45 billion/year to meet the additional load.

APPENDIX 3:
E3 STUDY



Outline

- Study Background & Context
- Methodology & Scenarios
- Key Inputs & Assumptions
- Results
- Conclusions

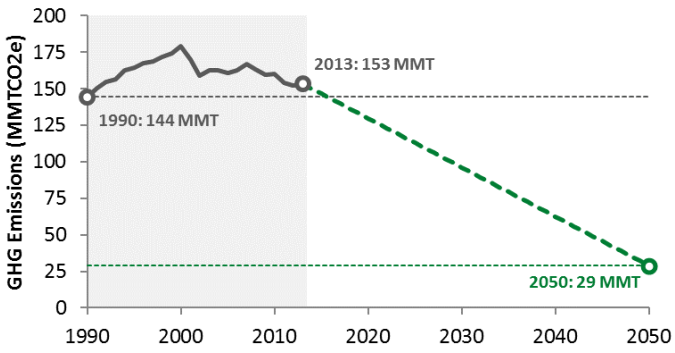
Energy+Environmental Economics

STUDY BACKGROUND & CONTEXT

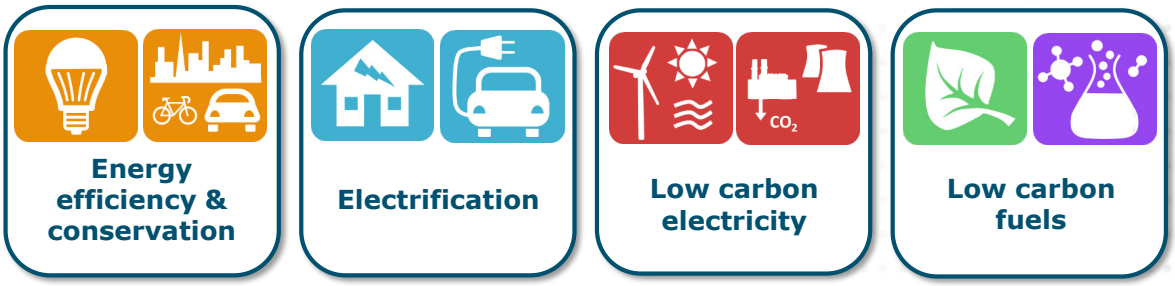
About This Study

- **Oregon and Washington are currently exploring potential commitments to deep decarbonization in line with international goals:**
  - Oregon: 91% below 1990 levels by 2050 (proposed)
  - Washington: 80% below 1990 levels by 2050 (proposed)
- **This study was conceived to inform policymakers on the effectiveness of various potential policies to reduce GHG emissions in the Northwest:**
  - What are the most cost-effective ways to reduce electricity sector emissions in the Northwest?
  - What is the value of existing carbon-free resources?
- **Study considers the unique characteristics of the Pacific Northwest**
  - Reliance on existing hydropower
  - Historical emphasis on conservation

Oregon and Washington Greenhouse Gas Emissions Trends



Four "Pillars" of Decarbonization to Meet Long-Term Goals

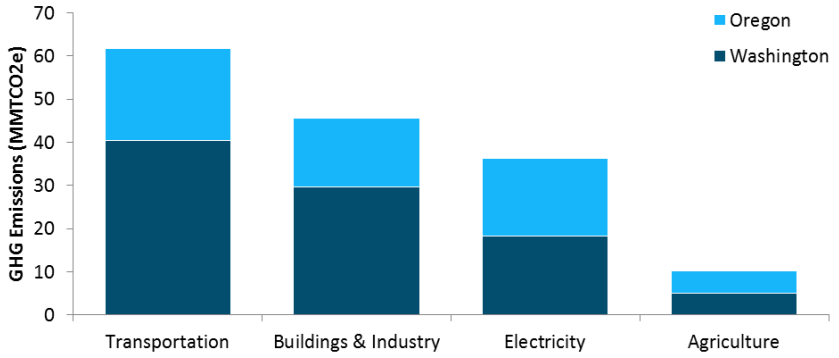


- **Four foundational elements are consistently identified in studies of strategies to meet deep decarbonization goals**
- **Across most decarbonization studies, electric sector plays a central role in meeting goals**
  - Through direct carbon reductions
  - Through electrification of loads to reduce emissions in other sectors

Meeting Long-Term GHG Goals Requires Reductions from All Sectors

+ **Largest sources of GHG emissions in the region guide prioritization of emission reduction strategies:**
  1. Transportation
  2. Buildings and industry
  3. Electricity

Oregon and Washington Greenhouse Gas Emissions by Sector (2013)



Sources: Report to the Legislature on Washington Greenhouse Gas Emissions Inventory: 2010 – 2013 (*link*); Oregon Greenhouse Gas In-boundary Inventory (*link*)

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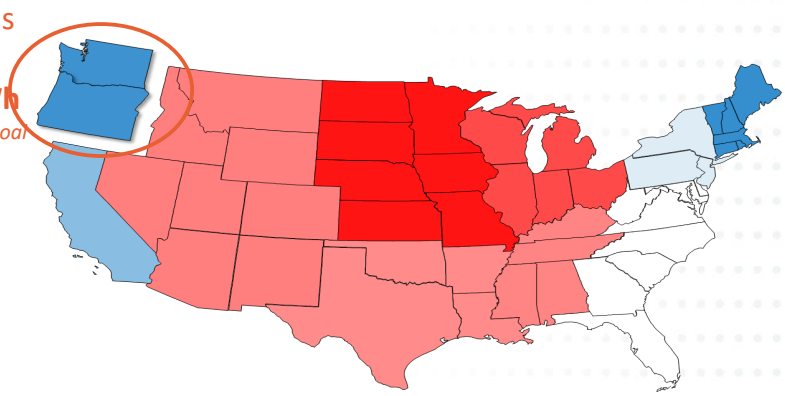
Carbon Intensity of the Northwest's Electricity Sector is Relatively Low

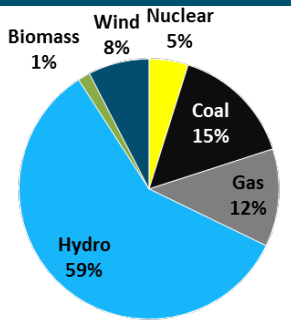
+ **Due to large fleet of existing zero-carbon resources, electric emissions intensity in the Pacific Northwest is already below other regions in the United States**

2013 Regional GHG Intensity of Electricity Supply (tons/MWh)

2013 emissions intensity:
0.26 tons/MWh
(includes out-of-state coal resources)



WA/OR Generation Mix



2013 Emissions Intensity (tons/MWh)												
0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80

Figure developed using data gathered from state 2013 GHG inventories for Washington, Oregon, and California; supplemented with data from EIA Annual Energy Outlook 2016

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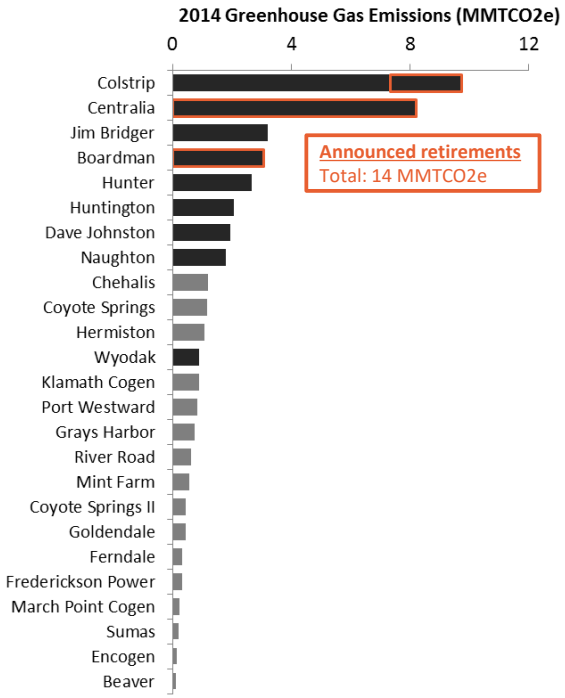
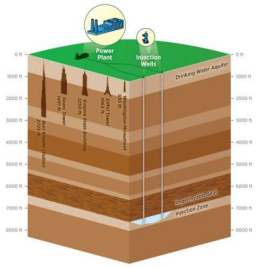
A Handful of Plants are Responsible for Most of the Electric Sector GHG Emissions in the Northwest



- **Existing coal plants (9 units) are responsible for 33 million metric tons of emissions—roughly 80% of all emissions attributed to Washington & Oregon**
  - Includes contracted generation in Montana, Wyoming
- **Existing gas generation accounts for roughly 9 million metric tons**

Low-Carbon Electricity Generation Becomes the Predominant Source of Primary Energy for the Entire Economy

1. **Renewable**
   - Hydroelectric: *flexible low-carbon resource in the Northwest that can help to balance wind and solar power*
   - Wind: *high quality resources in West, particularly East of the Rockies, intermittent availability*
   - Solar: *high quality resources across the West, intermittent availability*
   - Geothermal: *resource limited*
   - Biomass: *resource limited*
2. **Nuclear**
   - Conventional: *baseload low-carbon resource*
   - Small modular reactors: *potentially flexible low-carbon resource (not considered)*
3. **Fossil generation with carbon capture and storage (CCS)**



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METHODOLOGY & SCENARIOS

Overview of the Analysis

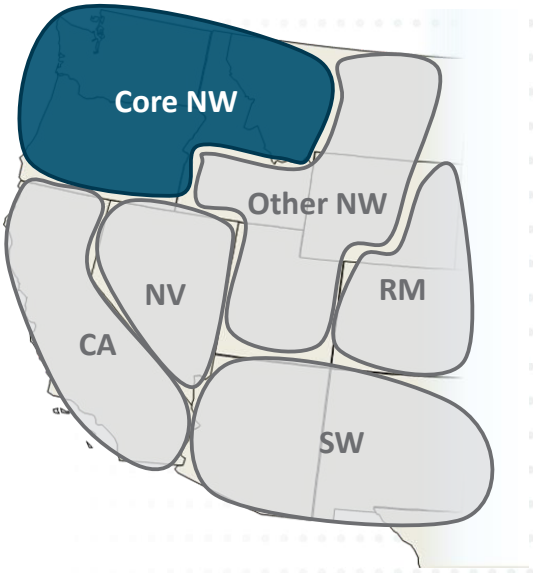
- **This study uses E3's Renewable Energy Solutions (RESOLVE) Model to select optimal portfolio of renewable and conventional resources for each scenario**
  - RESOLVE was designed for modeling operations and investments for high-renewable power systems
  - Utilized in several jurisdictions including California, Hawaii and New York
- **RESOLVE minimizes the sum of investment and operating costs over a defined time period**
  - Investment decisions are made every 10 years between 2020 and 2050
  - Performs optimal dispatch over a representative set of operating days in each year
- **Selects least-cost combination of resources over time**
  - Meets energy, capacity and balancing needs
  - Complies with RPS or GHG target ("overbuilding" portfolio if necessary)

Key Metrics Calculated by RESOLVE

Metric Description	Units
Resource additions for each investment period	MW and aMW
Total resource cost for combined electricity system during each model year	$/year
Annual generation by resource type	GWh or aMW
CO2 emissions	Metric tons/year
Renewable curtailment	GWh and % of available energy
Electricity market prices	Hourly $/MWh
Average and marginal CO2 abatement cost	$/metric ton

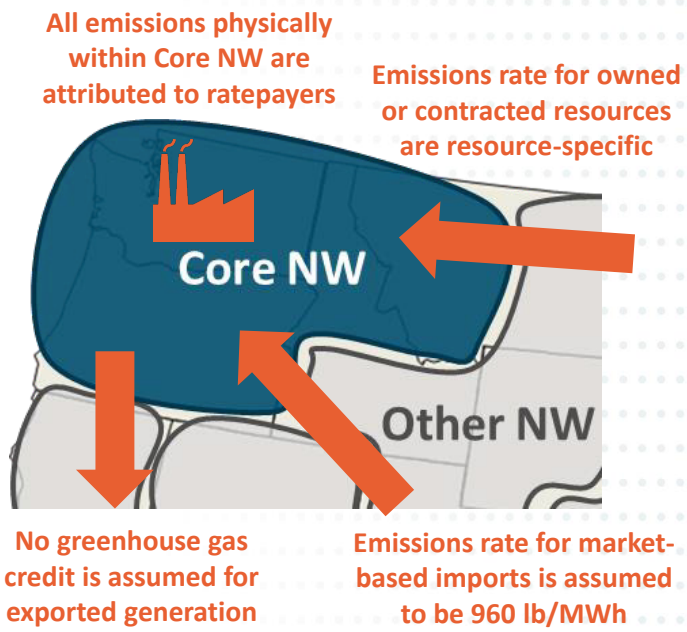
Study Footprint

- **RESOLVE is used to optimize a portfolio for "Core NW" loads in Washington, Oregon, northern Idaho and western Montana**
- **Remaining BAs of the WECC are grouped into five zones**
  - RESOLVE optimizes operations—but not investments—in external zones to reflect market opportunities for energy trading between regions in investment decisions
- **British Columbia and Alberta are not modeled**



Greenhouse Gas Accounting Conventions for Study Footprint

- **Study focuses on quantifying greenhouse gases associated with Core NW resource mix**
- **Accounting conventions mirror current cap & trade rules in California**
- **Emissions attributed to Core NW include:**
  - All fossil generation physically located in the Core NW
  - Ownership shares of remotely-owned coal plants
  - Economic imports, at an assumed rate of 960 lb/MWh
  - No GHG credit for exported generation



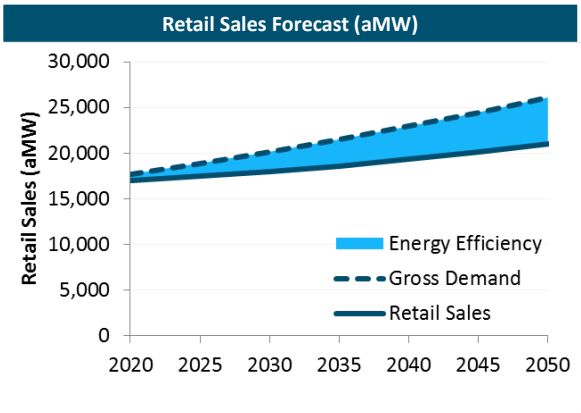
Overview of Core Policy Scenarios

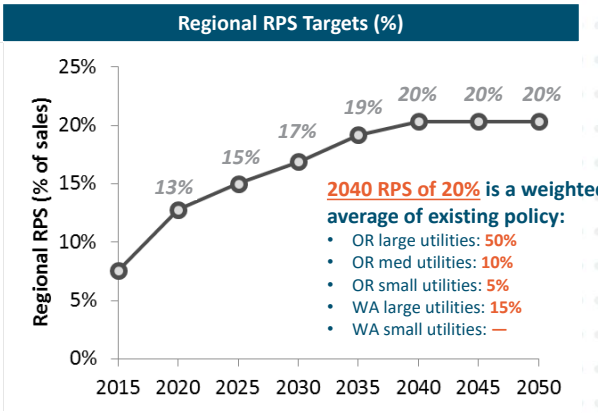
1. **Reference Case:** reflects current state policy and industry trends
2. **Carbon Cap Cases:** meet electric sector reduction goal through implementation of a carbon cap on the electric sector
   - **40%, 60%,** and **80%** GHG reduction by 2050
3. **Carbon Tax Cases:** impose an escalating carbon tax on the electric sector
   - **WA Leg. tax proposal** ($15/ton in 2020 escalating at 5.5%/yr. + inflation)
   - **WA Gov. tax proposal** ($25/ton in 2020 escalating at 3.0%/yr. + inflation)
4. **High RPS Cases:** impose increased RPS targets upon WA & OR utilities by 2050 as a policy mechanism to decarbonize the electric sector
   - **30%, 40%,** and **50%** RPS achieved regionally by 2050
5. **'No New Gas' Case:** prohibits construction of new gas generation

Reference Case

+ Reference Case captures current policies and trends:

- **Achievement of cost-effective energy efficiency** as identified in NWPCC 7th Power Plan
- **Announced coal plant retirements:** Boardman (2020), Colstrip 1 & 2 (2022), Centralia (2020/'24)
- **State- and utility-specific RPS goals:** achieves regionwide weighted average of 20% RPS by 2040

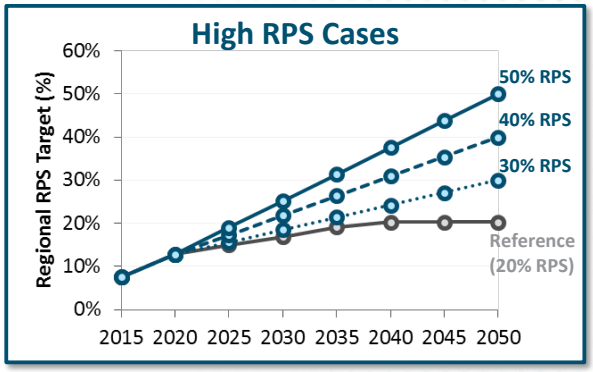


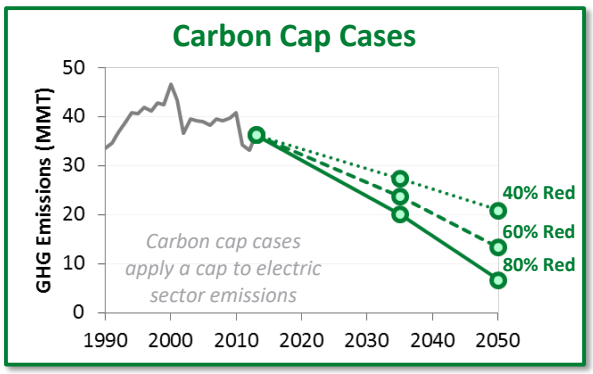


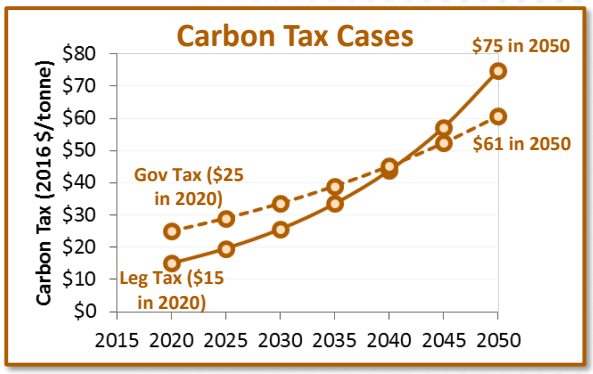
Core Policy Scenario Trajectories

+ Each scenario is defined by a set of goals, constraints, or cost assumptions through 2050

+ 'No New Gas' case prohibits construction of new gas generation across the entire horizon







Sensitivity Analysis Used to Explore Additional Questions

Sensitivity	Purpose
A. No Revenue Recycling	Examine impact to ratepayers if revenue collected under carbon pricing mechanism is not returned to the electricity sector
B. Loss of Existing Carbon-Free Resources	Examine the cost and GHG implications of decommissioning existing hydro and nuclear generation
C. High Energy Efficiency	Examine the potential role of higher-cost energy efficiency measures in a GHG-constrained future
D. High Electric Vehicles	Explore the role of vehicle as a potential strategy for reducing GHG emissions in the transportation sector
E. High & Low Gas Prices	Examine sensitivity of key learnings to assumptions on future natural gas prices
F. Low Technology Costs	Explore changes in cost and portfolio composition under assumptions of lower costs for solar, wind and energy storage
G. California 100% RPS	Explore implications of California clean energy policy on decarbonization in the Northwest

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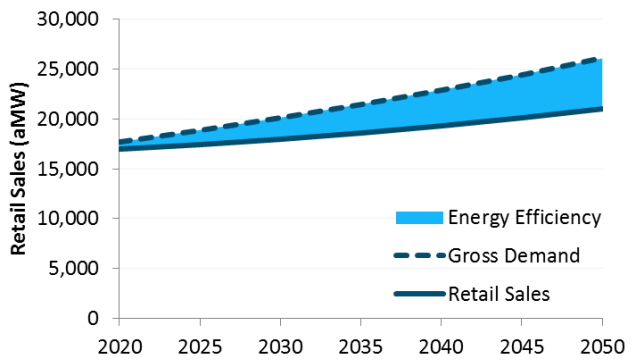
KEY INPUTS & ASSUMPTIONS

Demand Forecast Assumptions

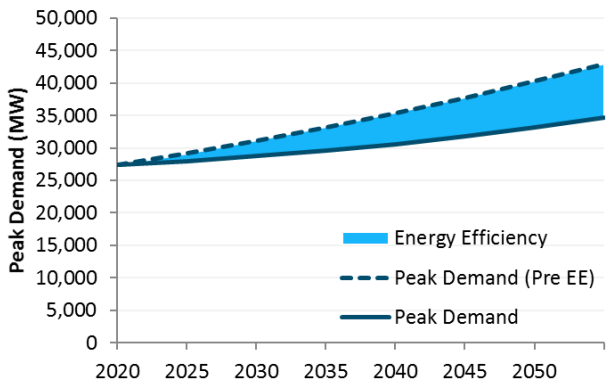
+ **Demand forecast benchmarked against multiple long-term projections**
  - Assumes 7th Power Plan EE is included in load
  - Average growth rate after efficiency: **0.7%/yr**

Source	Pre EE	Post EE
PNUCC Load Fcst	1.7%	0.9%
BPA White Book	1.1%	—
NWPCC 7th Plan	0.9%	0.0%
TEPPC 2026 CC	—	1.3%
E3 Recommended	**1.3%**	**0.7%**

Retail Sales Forecast (aMW)



Peak Demand Forecast (MW)

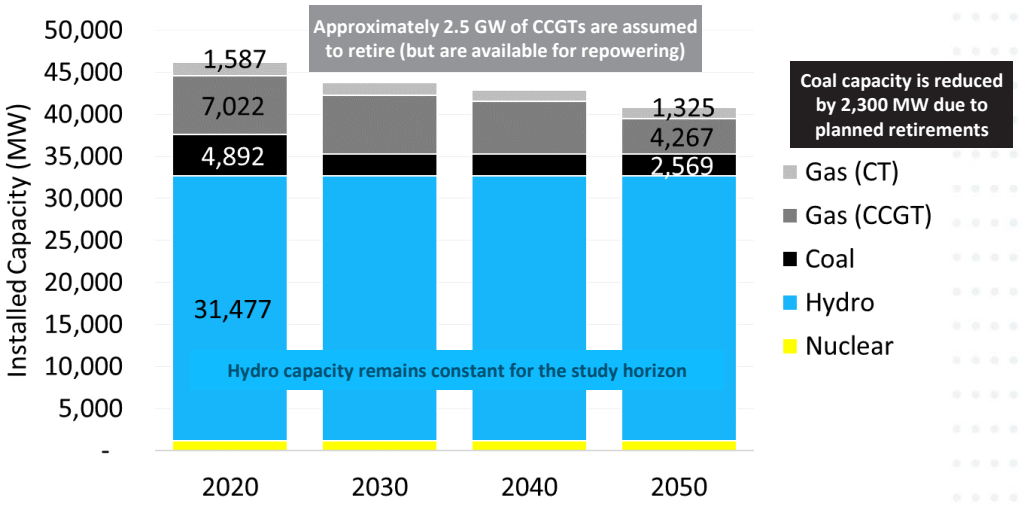


Existing Resource Assumptions
Conventional Generation

+ **Conventional fleet data is derived using TEPPC 2026 common case**
+ **Announced coal retirements included**
  - Boardman (2020)
  - Centralia 1 & 2 (2020/2024)
  - Colstrip 1 & 2 (2022)

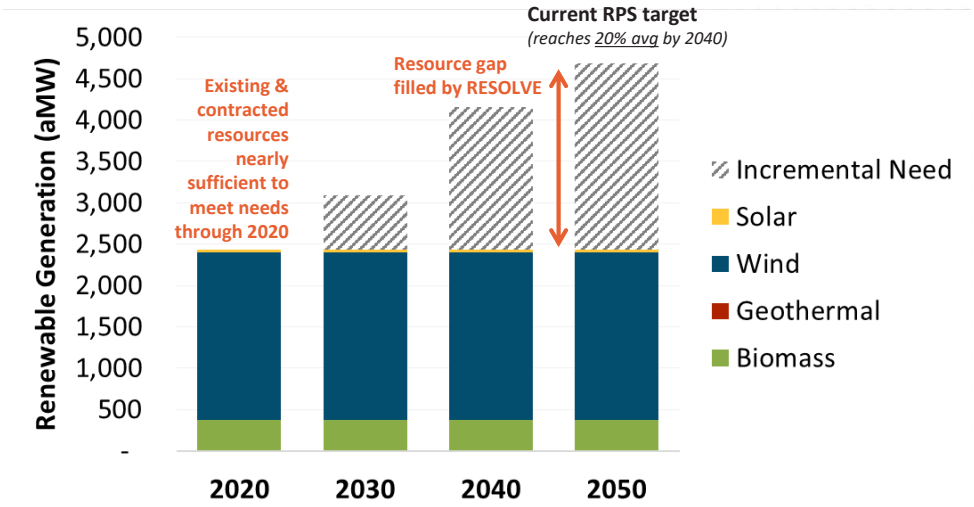
Remaining coal generation reflects OR/WA ownership shares of remote resources

+ **Remaining coal & nuclear remains online throughout analysis**



Existing Resource Assumptions
Renewable Generation

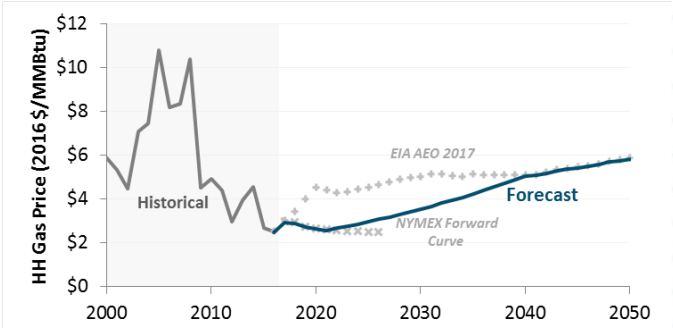
- **Baseline renewable portfolio includes existing resources and planned near-term additions**
  - All assumed to remain online indefinitely through analysis
  - Based on Western Electric Coordinating Council's 2026 Common Case
  - Excludes renewable resources contracted to California



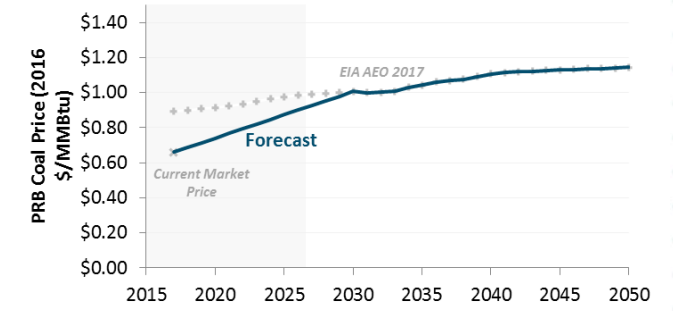
Fuel Price Forecasts

- **Gas price forecast blends market data and long-term fundamentals**
  - 2017-'21: NYMEX forwards
  - 2022-'40: transition
  - 2040-'50: EIA AEO 2017
- **Coal price forecast transitions from current market prices to long-term fundamental forecast**
  - 2017: current market data
  - 2030-'50: EIA AEO 2017
- **Basis differentials and adders for delivery applied**

Henry Hub Gas Price Forecast (2016 $/MMBtu)



Powder River Basin Coal Price ($/MMBtu)



Resource Options in RESOLVE

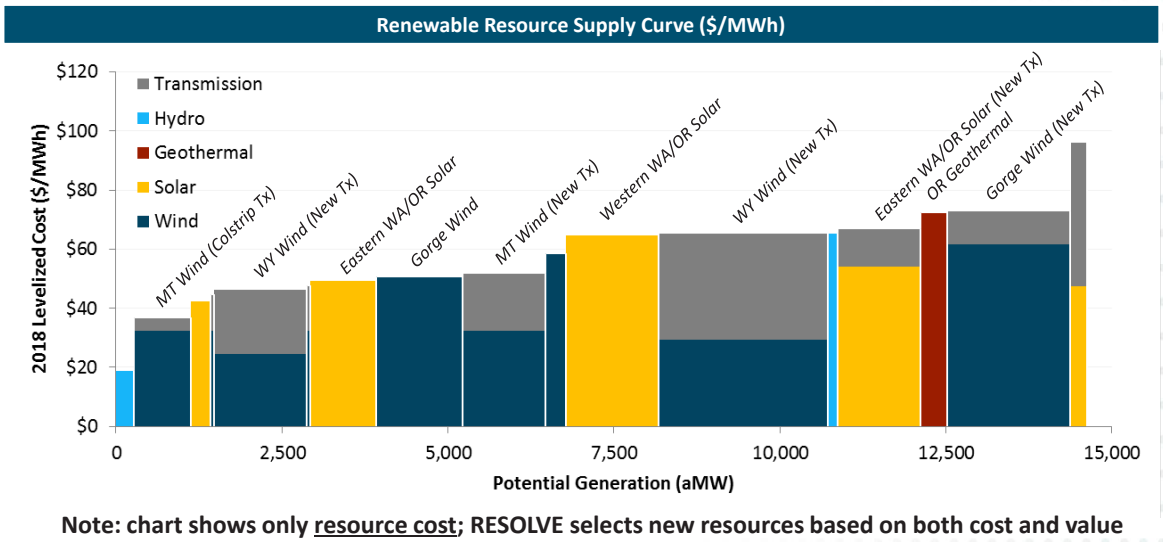
Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines • Repowered CCGTs	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting reserve needs and ramping constraints
Renewable Generation	• Geothermal • Hydro upgrades • Solar PV • Wind	• Produces zero-carbon generation that contributes to meeting RPS goals • Curtailable when necessary to help balance load
Energy Storage	• Batteries (>1 hr) • Pumped Storage (>12 hr)	• Stores excess energy for later use • Contributes to meeting reserve needs and ramping constraints
Energy Efficiency	• HVAC & appliances • Lighting	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Interruptible tariff (ag) • DLC: space & water heating (res)	• Contributes to planning reserve margin needs

New Resource Options
Natural Gas Generation

- **Four options for new gas generation are considered:**
  - Frame combustion turbines
  - Repowering of retiring combined cycle gas turbines (assumed cost of 75% of new CCGT cost)
  - Reciprocating engines
  - New CCGTs
- **Costs and characteristics of new gas units are based on E3's "Cost and Performance Assessment of Generation Technologies" study prepared for WECC**
  - Capital cost of new gas generation assumed to remain constant in real terms over time

New Resource Options
Renewable Generation

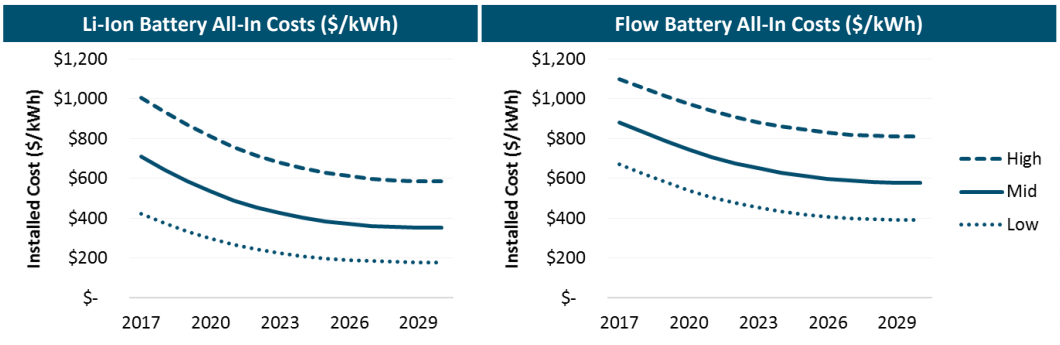
- **Renewable supply curve captures regional and technological diversity of options for renewable development**
  - Adders for new transmission and wheeling included as necessary
- **Resources selected based on value and "fit" in addition to cost**



Note: chart shows only resource cost; RESOLVE selects new resources based on both cost and value

New Resource Options
Energy Storage

- **Assumptions on energy storage cost drive cost-effectiveness of investments in integration solutions**
- **Battery cost assumptions (current & future) derived from Lazard Levelized Cost of Storage 2.0**

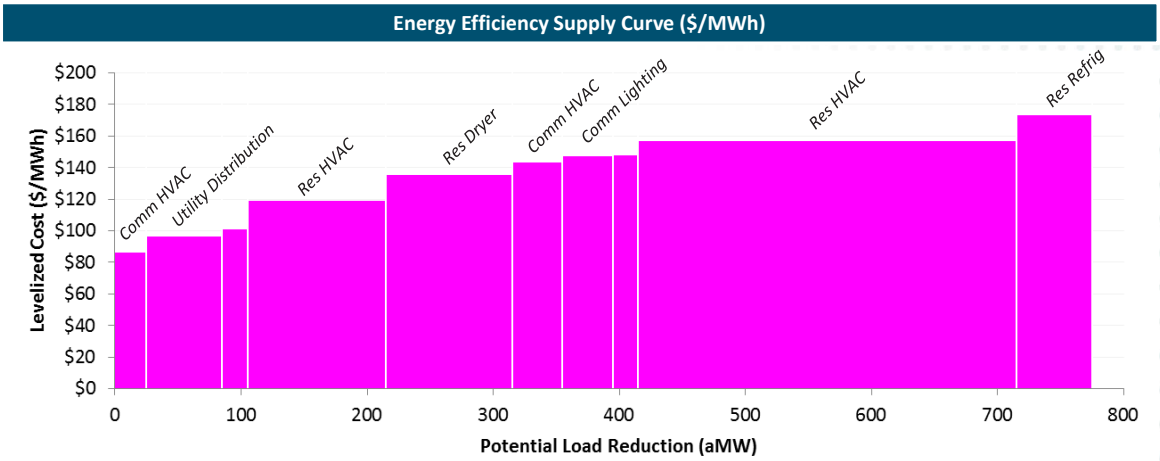


Capital costs shown for 4-hr storage devices; RESOLVE can select optimal duration for energy storage resources

- **Pumped storage assumed to cost $2,875/kW**
  - Limited to 5,000 MW of potential in Northwest

New Resource Options
Incremental Energy Efficiency

- **Supply curve of incremental energy efficiency constructed from measures identified in the NWPCC Seventh Power Plan as "not cost effective"**
  - Resources bundled by cost and end use for purpose of selection in RESOLVE



Note: chart shows only EE measures that are treated as options in RESOLVE; all EE identified by NWPCC as cost-effective is included in the load forecast

New Resource Options
Demand Response

- **Demand response cost & potential incorporated from Navigant's *Assessing Demand Response Program Potential for the Seventh Power Plan***
- **From this study, two DR resources—representing the majority of winter peak load reduction potential—are included in RESOLVE:**
  1. **Agricultural interruptible tariff:** **657 MW** available by 2050 at a cost of **$19/kW-yr.**
  2. **Residential space & water heating direct load control (DLC):** **902 MW** available by 2050 at a cost of **$59/kW-yr.**

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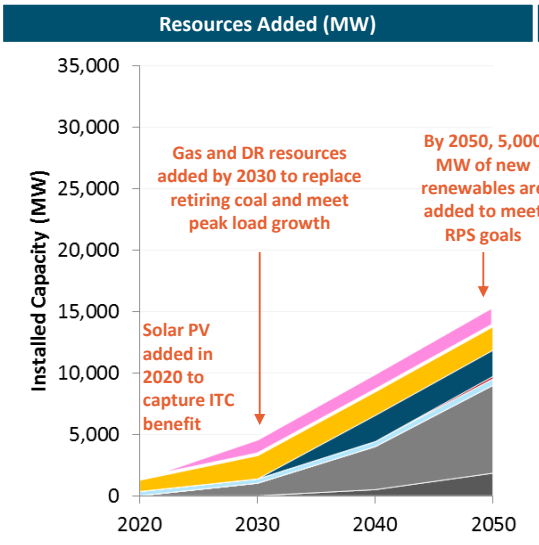
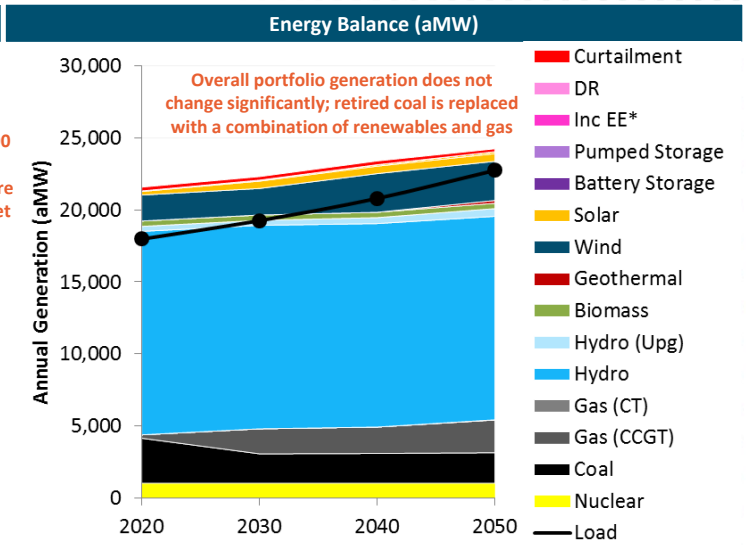
CORE POLICY SCENARIOS: PORTFOLIO SUMMARIES

Portfolio Summary
Reference Case

- New gas gen. and DR added after 2020 to meet capacity needs
- Planned coal retirements result in increased reliance on gas generation
- By 2050, 5 GW of renewable resources are needed to meet RPS goals



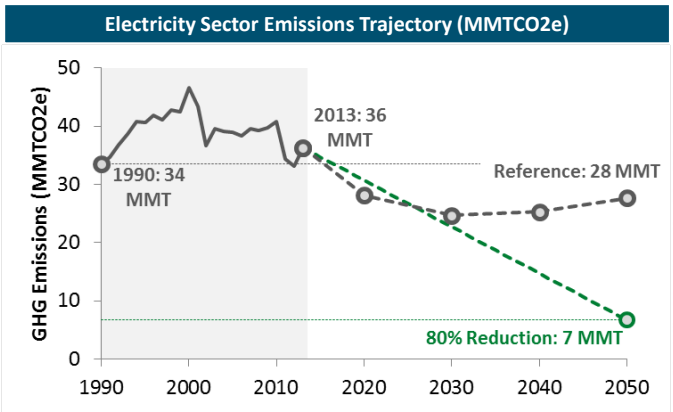


* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

Emissions Trajectory
Reference Case

+ **Through 2030, current policies and trends result in emissions reductions that are generally consistent with long-term goals**
  - Load growth limited by cost-effective energy efficiency
  - 2,500 MW of renewable generation added to meet RPS policy goals by 2030
  - 2,300 MW of coal capacity retired

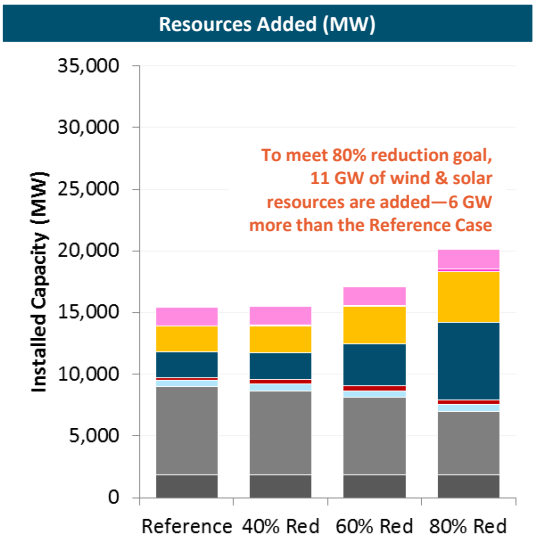
+ **Additional measures are needed to meet long-term goals beyond 2030**
  - Coal generation remains the largest source of emissions beyond 2030
  - Additional gas generation & imports are needed to meet load growth
  - Emissions start to trend back up after 2030 without new policy

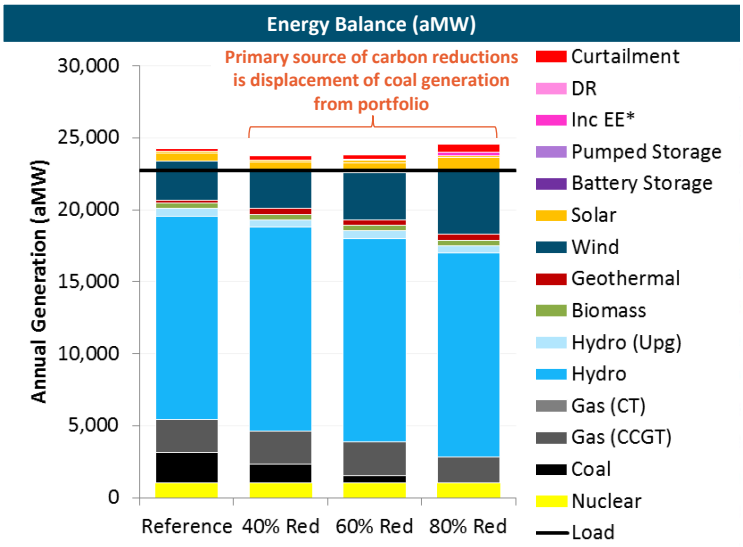


2050 Portfolio Summary
Carbon Cap Scenarios

Highlights
- Coal retired under 80% Case, replaced with renewables & gas
- 11 GW of new renewables by 2050
- 7 GW of new gas capacity added
- Gas capacity factor is 30% in 2050

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Reference	—	—	20%	91%
40% Reduction	+$163	7.5	21%	92%
60% Reduction	+$434	14.2	25%	95%
80% Reduction	+$1,046	20.9	31%	102%





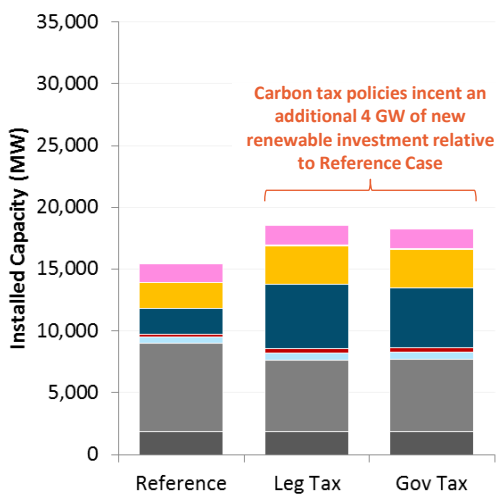
* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

2050 Portfolio Summary
Carbon Tax Scenarios

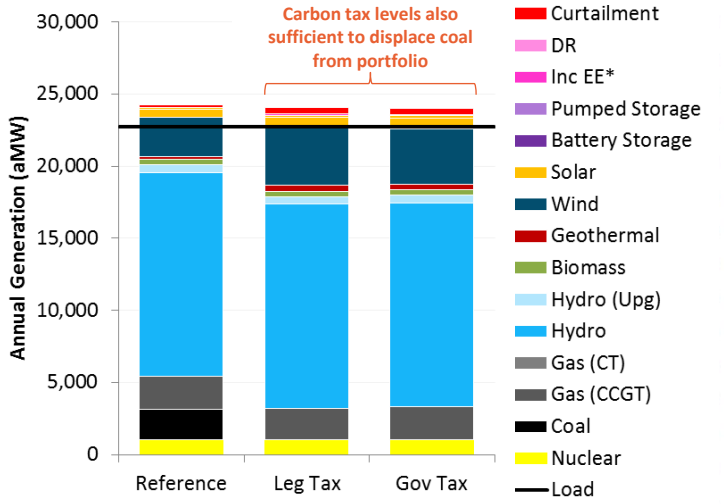
Highlights
- Coal retired under both cases and replaced with renewables & gas
- 9 GW of new renewables needed
- Carbon tax and cap lead to similar outcomes with these resource costs

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Reference	—	—	20%	91%
Leg Tax ($15-75)	+$804	19.1	28%	99%
Gov Tax ($25-61)	+$775	18.7	28%	99%

Resources Added (MW)



Energy Balance (aMW)



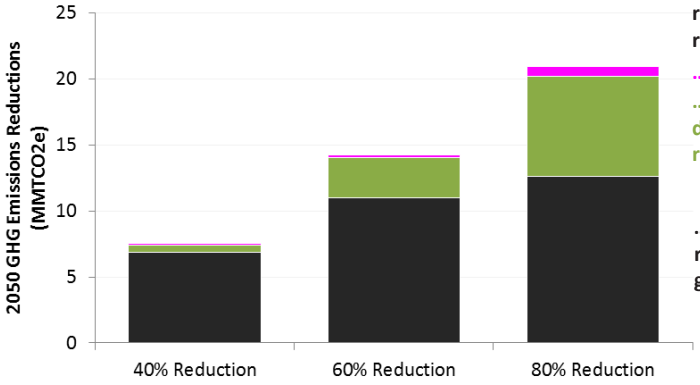
* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

Sources of Carbon Reductions in GHG Constrained Cases

+ Three key strategies needed to meet 80% reduction goals:

1. **Coal displacement:** reduced utilization and/or retirement of existing coal resources & replacement with natural gas
2. **Renewables:** displacement of gas & coal generation with additional investment in renewable generation
3. **Energy efficiency:** reductions in load due to additional energy efficiency

Emissions Reductions Relative to Reference Case (MMTCO2e)



Of the 21 MMT of emissions reductions needed to meet the 80% reduction goal…

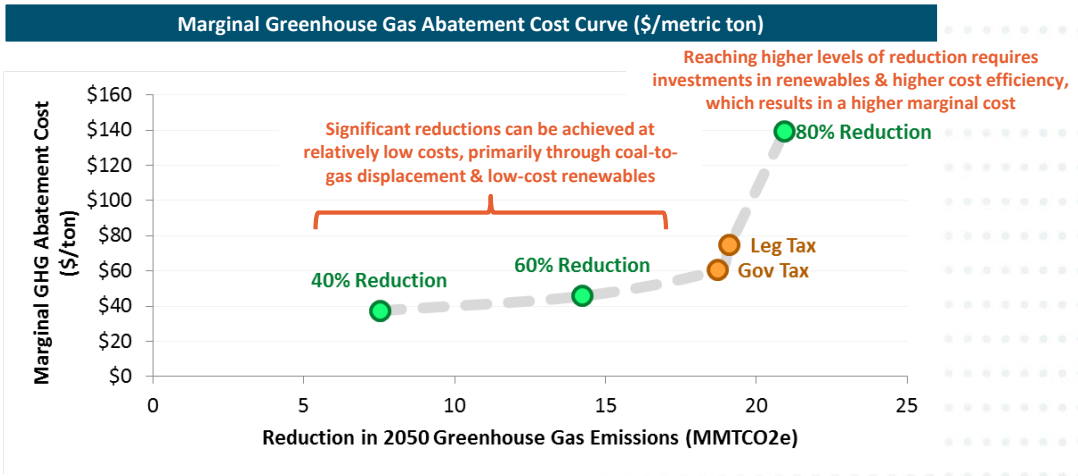
…1 MMT is due to incremental EE

…7 MMT result from displacement of natural gas with renewables

…13 MMT are a result of the retirement of existing coal generation

Marginal Greenhouse Gas Abatement Costs

- **Shape of GHG marginal cost curve highlights (1) low-hanging fruit; and (2) high cost of final mitigation measures needed to meet 2050 targets**
- **GHG abatement results of carbon tax scenarios are consistent with scenarios based on targets**



Note: marginal GHG abatement cost based on shadow price of GHG constraint for GHG policy scenarios; based on assumed 2050 carbon tax for tax scenarios

Carbon Tax vs. Cap-and-Trade: Qualitative Factors

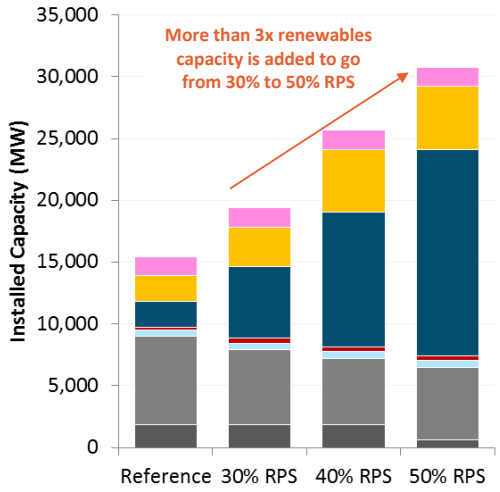
Resource Option	Carbon Tax	Carbon Cap-and-Trade
Compliance mechanism	Pay tax on each ton of CO2 emissions	Surrender carbon allowance for each ton of CO2 emissions
Disposition of funds collected	Tax revenue appropriated through legislative process	Allowances can be auctioned or allocated to affected companies; auction revenues administered by state agency (e.g., DEQ)
Breadth of carbon abatement options	In-state abatement options only	Ability to link with regional carbon markets to expand liquidity
Effect on electric markets	Potential for multiple prices on carbon within Western Interconnection creates challenges for market liquidity and interconnected operations	Single regional price on carbon would preserve wholesale power market liquidity and avoid operational wrinkles
Emissions reductions	Carbon price is fixed but actual emissions levels would vary	Emissions levels are specified, but carbon price would vary over time as abatement costs change

2050 Portfolio Summary
High RPS Scenarios

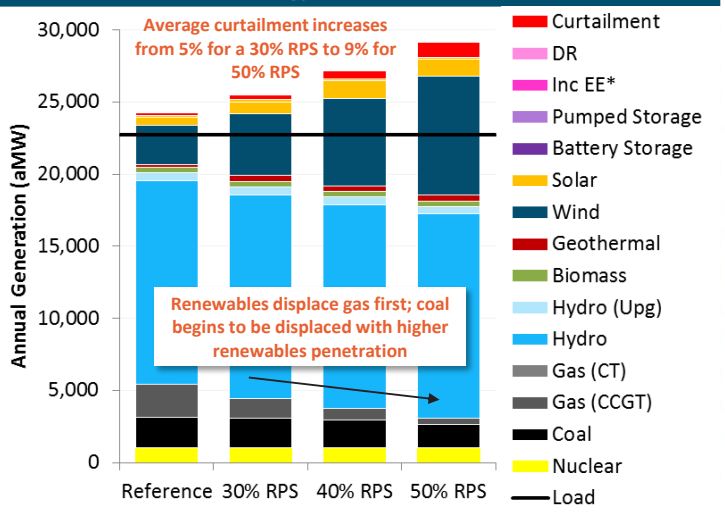
Highlights
- 23 GW of new renewables needed to meet a 50% RPS by 2050
- Curtailment increases to 9% of available renewable energy
- Coal provides most thermal energy

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Reference	—	—	20%	91%
30% RPS	+$330	4.3	30%	101%
40% RPS	+$1,077	7.5	40%	111%
50% RPS	+$2,146	11.5	50%	121%

Resources Added (MW)



Energy Balance (aMW)

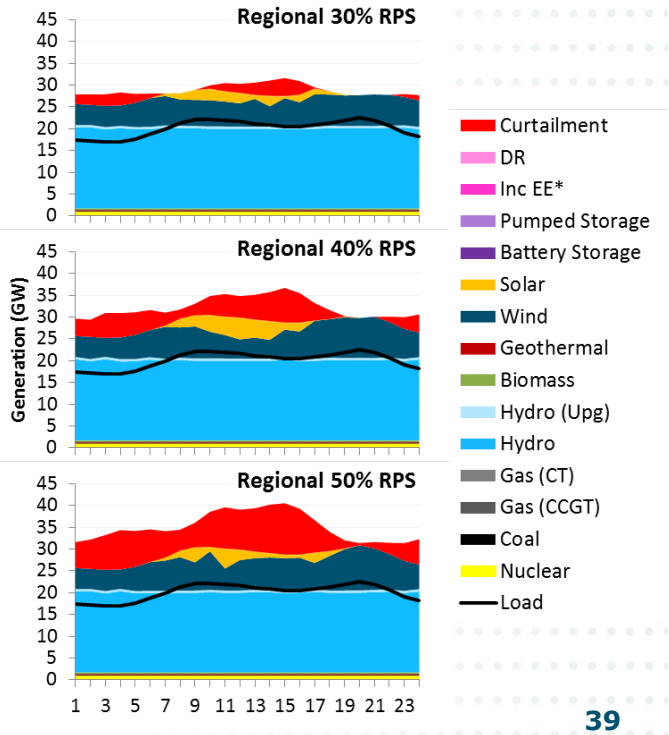


* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

Renewable Curtailment Becomes the Primary Integration Challenge

- **Higher renewable generation results in increased frequency and magnitude of renewable curtailment**
- **A significant proportion of incremental renewable generation above 30% RPS is either exported or curtailed**
- **Predominance of hydropower contributes to renewable curtailment but already serves as a zero-carbon baseload power source in the region**

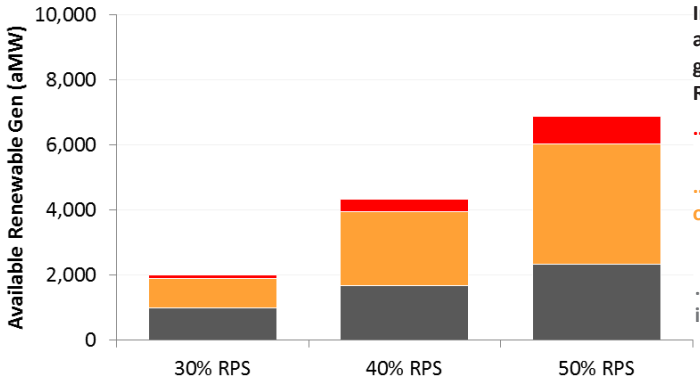
Snapshot of Daily Operations on a High Hydro Day (2050)



Impact of Incremental Renewables on Carbon is Limited

- **Under High RPS policies, renewables become less effective at reducing carbon in the Northwest, as large shares of generation are either exported or curtailed**
- **Frequency and magnitude of renewable curtailment events grows considerably, driving up cost of meeting RPS targets**

Impact of Incremental Renewable Resources Added (aMW)



In the 50% RPS case, roughly 7,000 aMW of potential renewable generation are added to the Reference Case. Of this total…

…12% is curtailed

…55% is exported to other parts of WECC

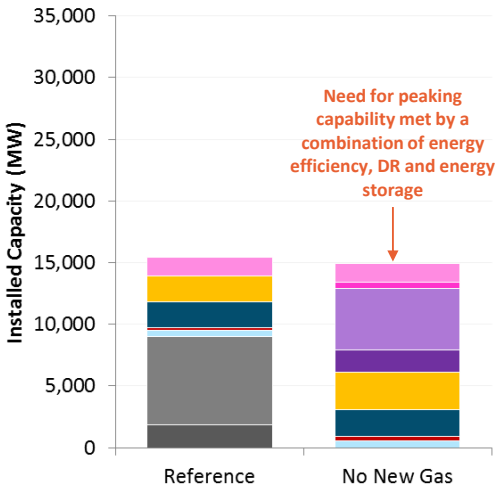
…33% displaces fossil generation in the Northwest

2050 Portfolio Summary
No New Gas Scenario

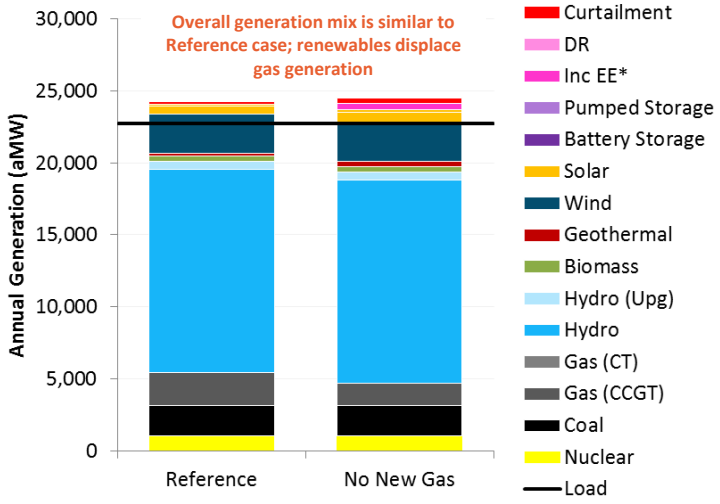
Highlights
- 7 GW of new energy storage added to meet capacity needs
- Very little change in coal & gas generation or GHG emissions

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Reference	—	—	20%	91%
No New Gas	+$1,202	2.0	22%	93%

Resources Added (MW)



Energy Balance (aMW)



* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

No New Gas Scenario Might Not Be Resource Adequate After 2025

- **New resources are needed in 2025-2030 time frame to ensure resource adequacy due to coal plant retirements and load growth**
  - Primary source of capacity added under No New Gas Case is energy storage (pumped hydro & batteries)
- **Storage provides capacity to help meet peak demands but does not generate energy that is needed during low hydro years or multi-day low generation events**
- **More study is needed to analyze whether the system as modeled meets reliability expectations**
  - The 'No New Gas' portfolio meets the current reserve margin requirement with the addition of new energy storage
  - However, it is unclear how much energy storage can contribute to Resource Adequacy in the Pacific Northwest

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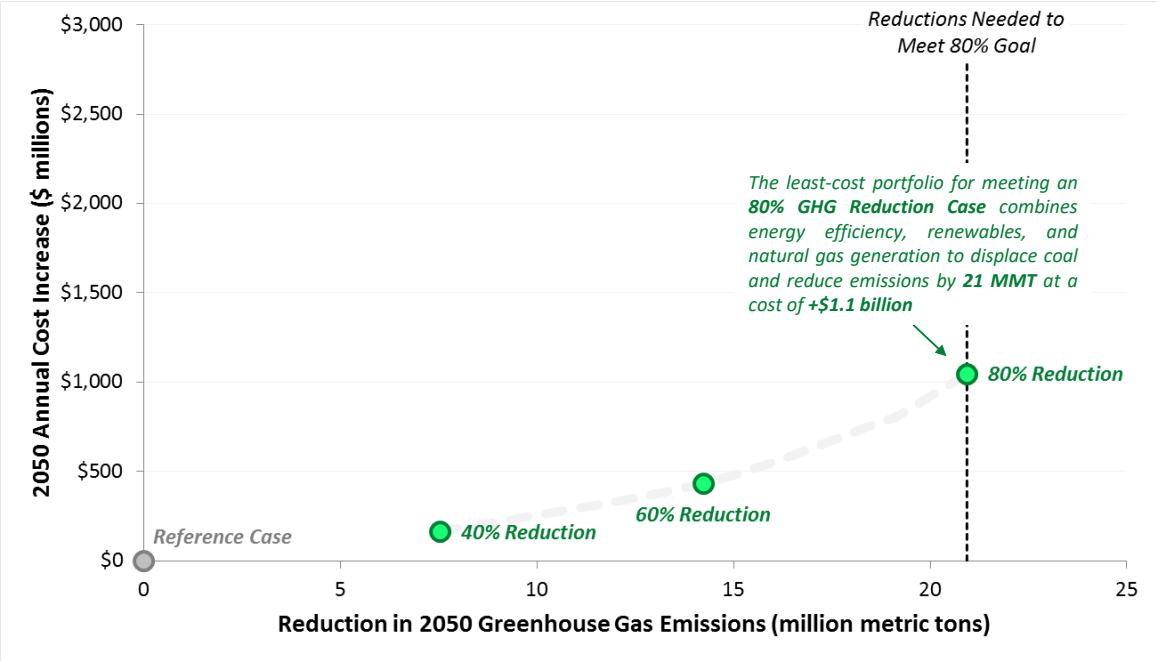
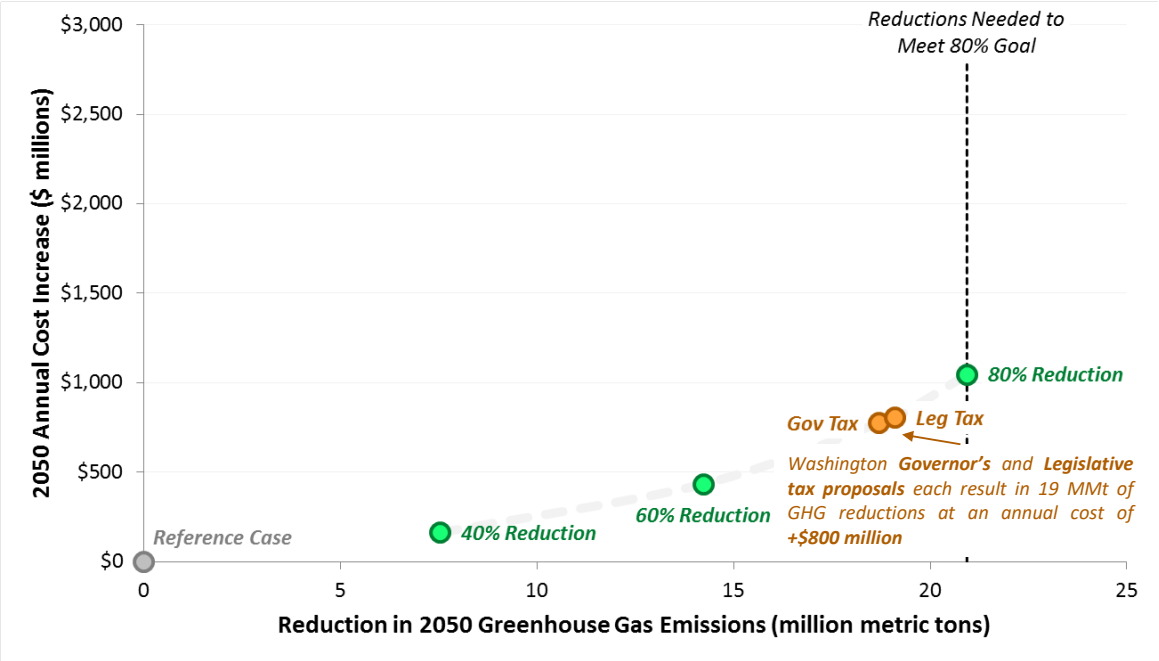
CORE POLICY SCENARIOS: SUMMARY OF COST & EMISSIONS IMPACTS

Cost & Emissions Impacts
Carbon Cap Cases



Note: Reference Case reflects current industry trends and state policies, including Oregon's 50% RPS goal for IOUs and Washington's 15% RPS for large utilities

Cost & Emissions Impacts
Carbon Tax Cases



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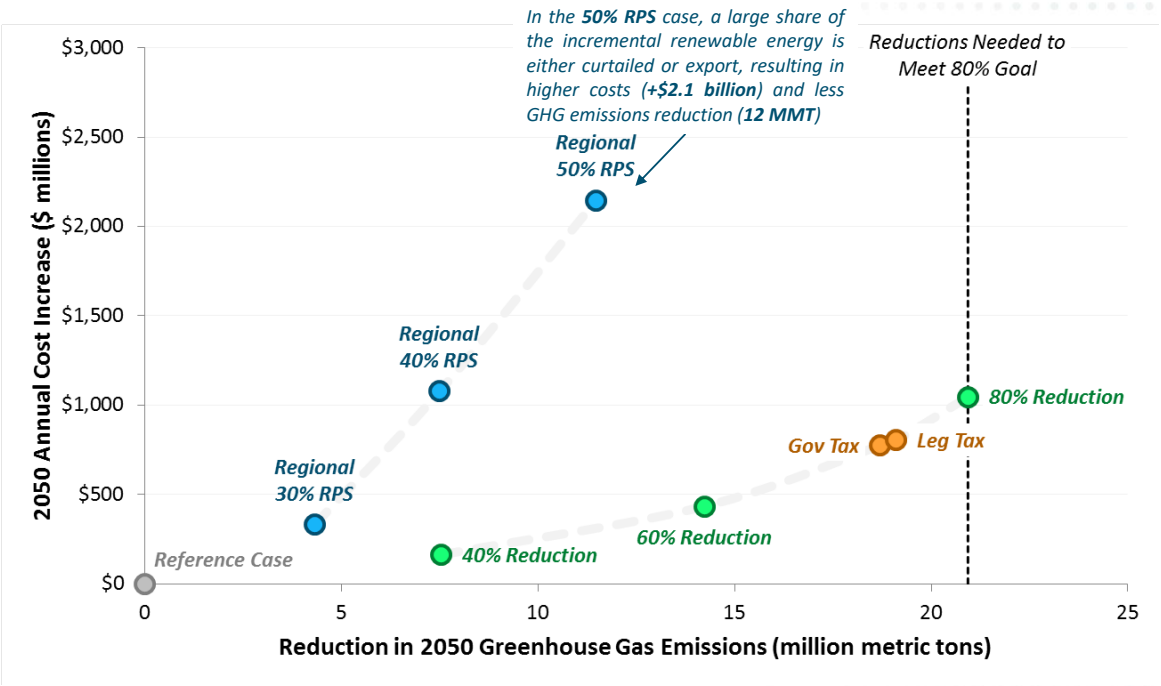
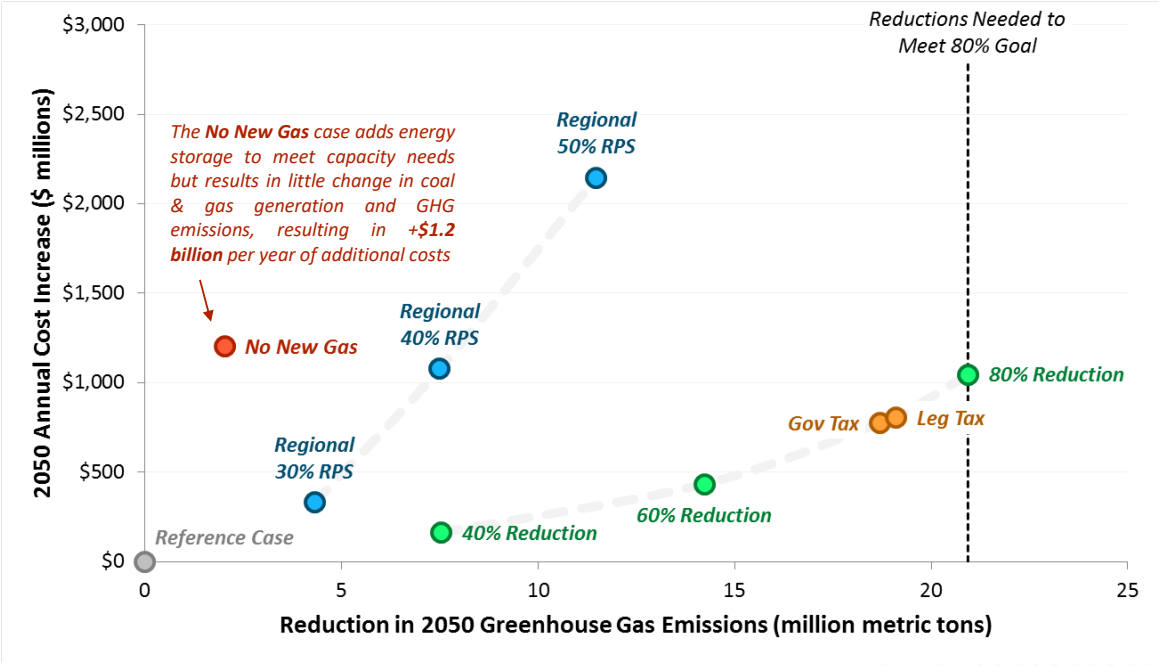
Cost & Emissions Impacts
High RPS Cases



Note: Reference Case reflects current industry trends and state policies, including Oregon's 50% RPS goal for IOUs and Washington's 15% RPS for large utilities

Cost & Emissions Impacts
No New Gas Case



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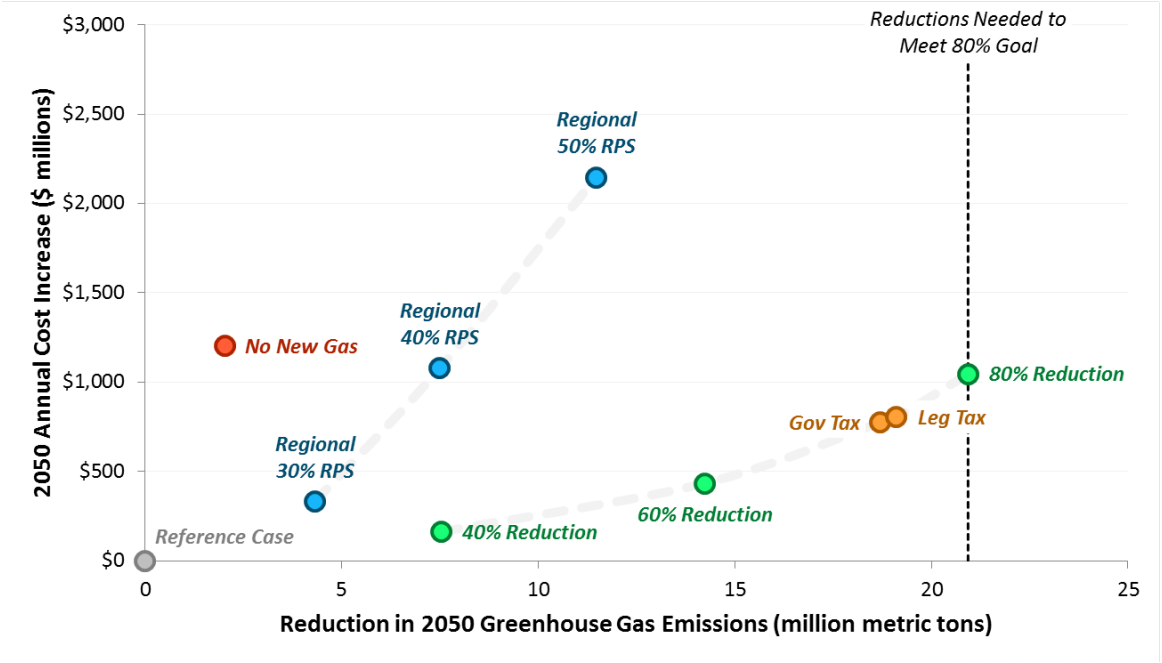
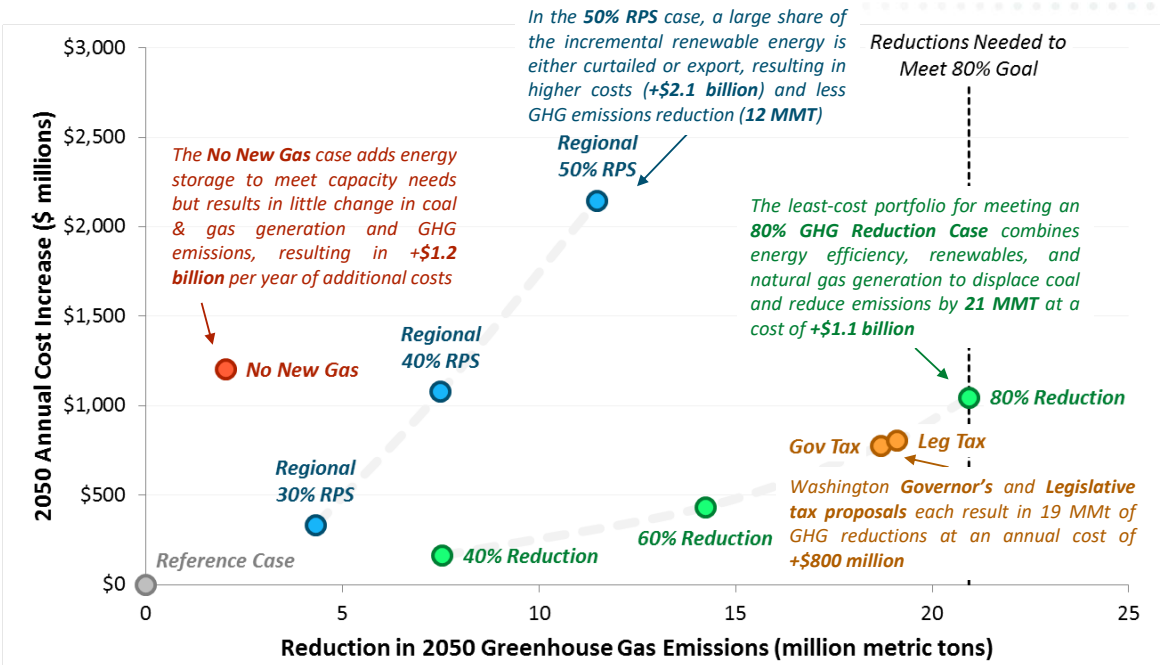
Cost & Emissions Impacts
All Cases



Note: Reference Case reflects current industry trends and state policies, including Oregon's 50% RPS goal for IOUs and Washington's 15% RPS for large utilities

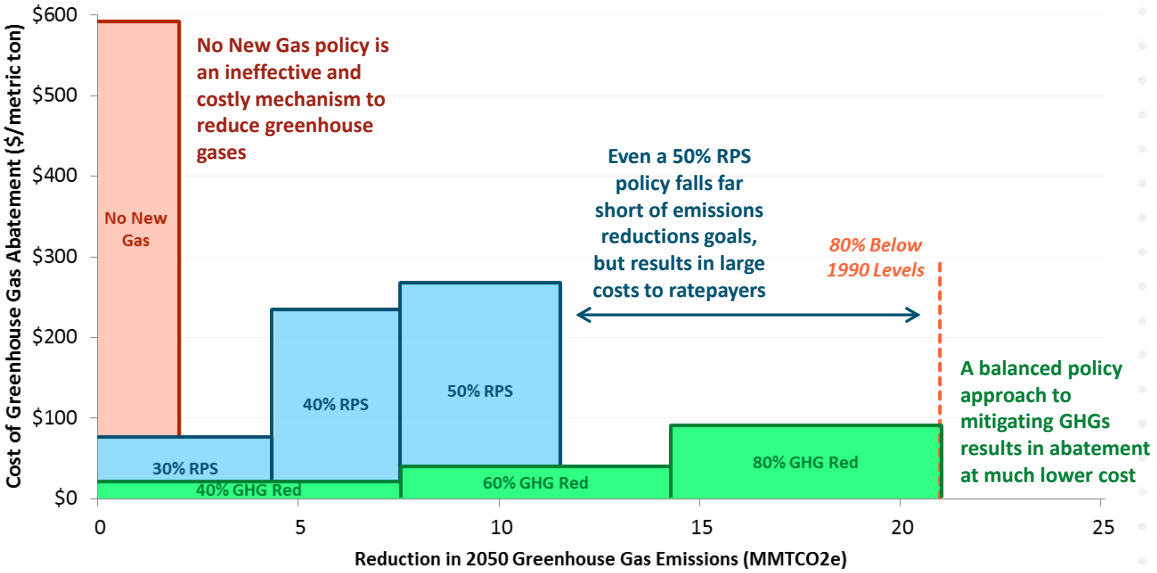
Cost & Emissions Impacts
All Cases



Note: Reference Case reflects current industry trends and state policies, including Oregon's 50% RPS goal for IOUs and Washington's 15% RPS for large utilities

Cost of GHG Abatement

+ Shape of GHG marginal cost curve highlights (1) low-hanging fruit; and (2) high cost of final mitigation measures needed to meet 2050 targets



2050 Scenario Summary

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Avg GHG Abatement Cost ($/ton)	Effective RPS %	Zero Carbon %	Renewable Curtailment (aMW)
Reference	—	—	—	20%	91%	201
40% Reduction	+$163	7.5	$22	21%	92%	294
60% Reduction	+$434	14.2	$30	25%	95%	364
80% Reduction	+$1,046	20.9	$50	31%	102%	546
30% RPS	+$330	4.3	$77	30%	101%	313
40% RPS	+$1,077	7.5	$144	40%	111%	580
50% RPS	+$2,146	11.5	$187	50%	121%	1,033
Leg Tax ($15-75)	+$804	19.1	$42	28%	99%	437
Gov Tax ($25-61)	+$775	18.7	$41	28%	99%	424
No New Gas	+$1,202	2.0	$592	22%	93%	337

Incremental cost and GHG reductions are measured relative to the Reference Case

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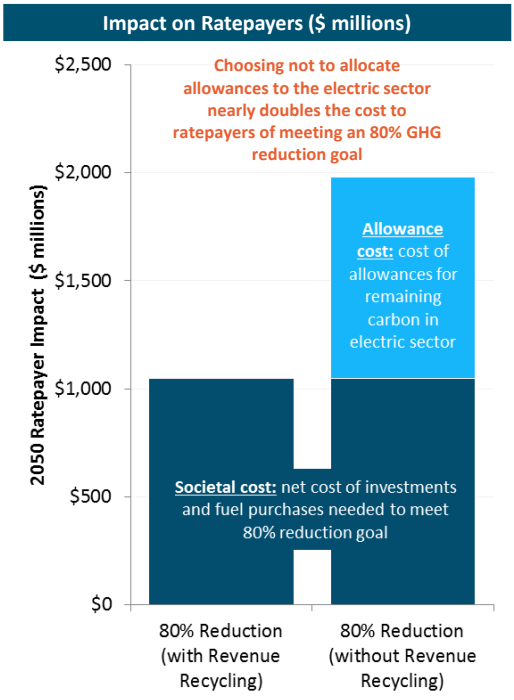
SENSITIVITY RESULTS

No Revenue Recycling

Disposition of Revenues from Carbon Pricing is Important for Cost Mitigation

- **The primary cost metric in this analysis is the incremental <u>societal</u> cost associated with each policy**
  - Reflects costs of burning more expensive fuel and investing in more expensive generation resources
- **Ratepayer costs may not align with societal costs**
  - Returning or "recycling" revenues from cap/tax would mitigate impact on electric ratepayers
  - If revenues from cap/tax are diverted to other uses, ratepayer impact will be larger
- **Most jurisdictions that have implemented carbon pricing have included revenue recycling to mitigate cost to ratepayers**



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SENSITIVITY RESULTS

Existing Resource Retirement

Retirement of Existing Zero-Carbon Generation

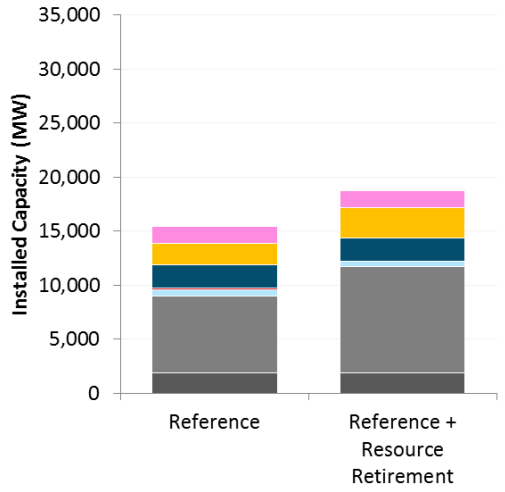
- **In order to highlight the value of existing zero carbon (non-RPS-qualifying) resources—and their key role in meeting GHG goals—E3 evaluated a sensitivity in which approximately 2,000 aMW of nuclear & hydro was assumed to retire:**
  - Columbia Generating Station (1,207 MW)
  - 1,000 aMW of generic existing hydro
- **Sensitivity analysis conducted on Reference Case (current policy), 80% GHG Reduction Case and 50% RPS Case**

2050 Portfolio Summary
Reference Case (Existing Resource Retirement)

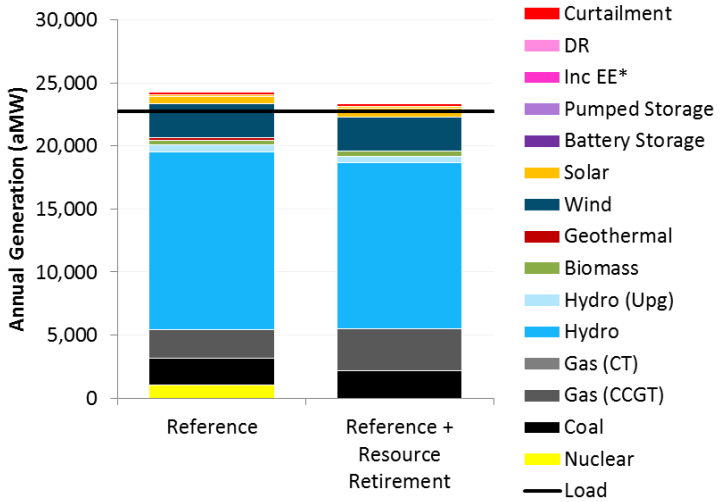
Highlights
- Under Reference Case, retiring resources are replaced with gas generation
- Results in both higher costs and GHG emissions

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	—	—	20%	91%
Retirement Case	+$1,071	-5.1	20%	82%
Delta	+$1,071	-5.1	—	-9%

Selected Resources (MW)



Energy Balance (aMW)



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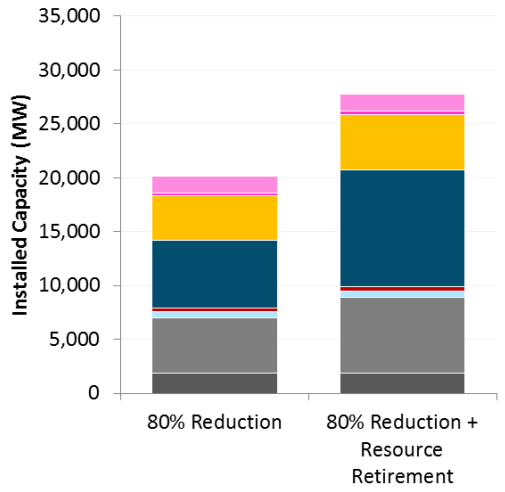
* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

2050 Portfolio Summary
80% Reduction (Existing Resource Retirement)

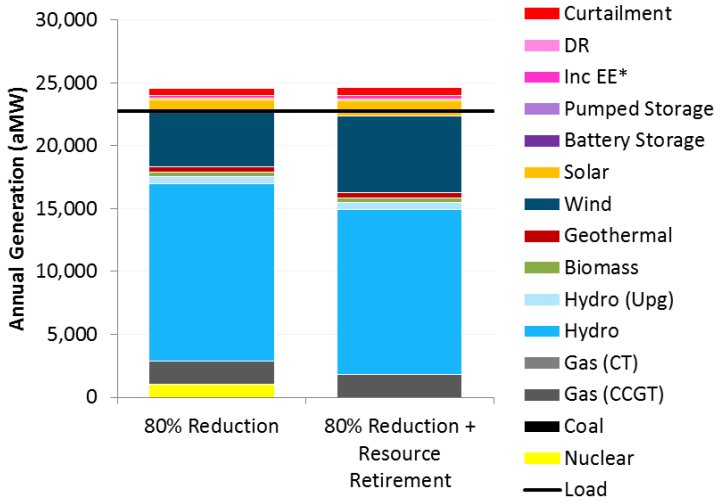
Highlights
- Under 80% GHG reduction scenario, retiring carbon-free resources replaced with 5.5 GW of renewables and 2 GW of gas
- Cost to meet goal increases $1.6 B

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	+$1,046	20.9	31%	102%
Retirement Case	+$2,652	20.9	40%	102%
Delta	+$1,606	—	+9%	—

Selected Resources (MW)



Energy Balance (aMW)



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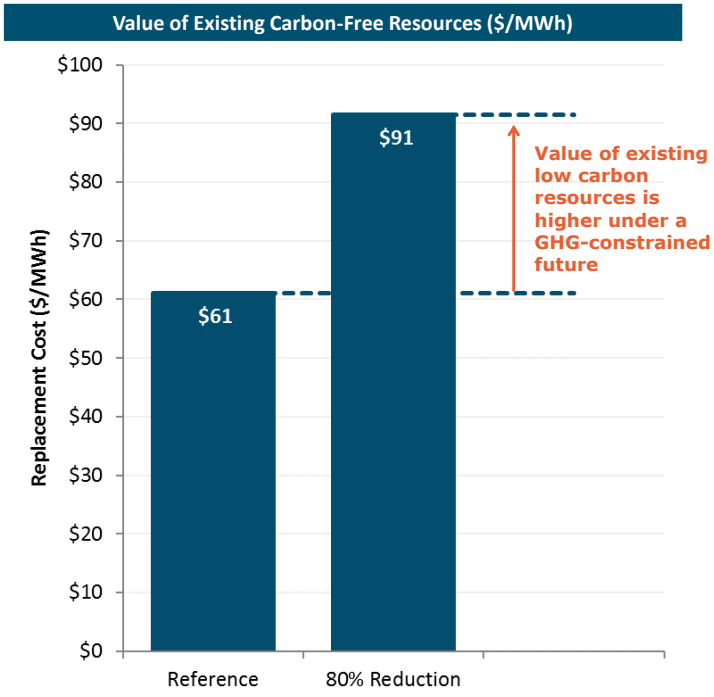
Value of Existing Zero Carbon Gen Increases Under GHG Constraints



- In the Reference Case, lost capacity and energy is replaced with natural gas generation
- In the 80% GHG Reduction Case, lost energy is replaced with 5500 MW of renewables and lost capacity is replaced with 2000 MW of gas generation
- Higher value in a carbon constrained world reflects the significant increase in cost to meet GHG policy goals should existing low carbon resources retire

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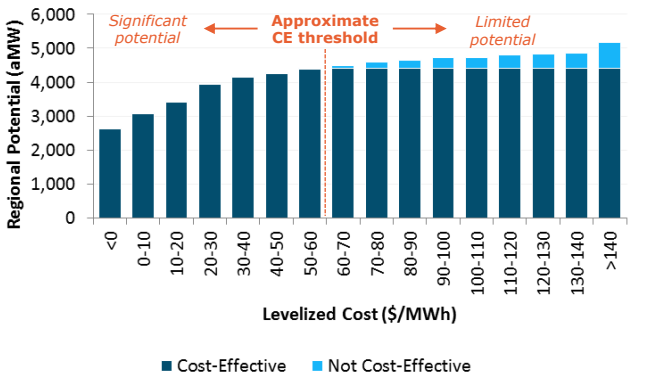
SENSITIVITY RESULTS

High Incremental Energy Efficiency Potential

High Energy Efficiency Sensitivity

- **This study relies on the NWPCC Seventh Power Plan for its characterization of energy efficiency:**
  - All cost-effective efficiency integrated into demand forecast
  - Additional measures available for selection in RESOLVE
- **Beyond the cost-effectiveness threshold, NWPCC's supply curve for efficiency measures flattens out—limited additional potential has been identified**
- **This sensitivity tests the impact of allowing RESOLVE to select additional high-cost EE measures**
  - 1,000 aMW of additional potential a a cost of $110/MWh
- **Purpose of sensitivity is to explore whether additional focus on EE is merited under GHG policy**

NWPCC Energy Efficiency Supply Curve



2050 Portfolio Summary

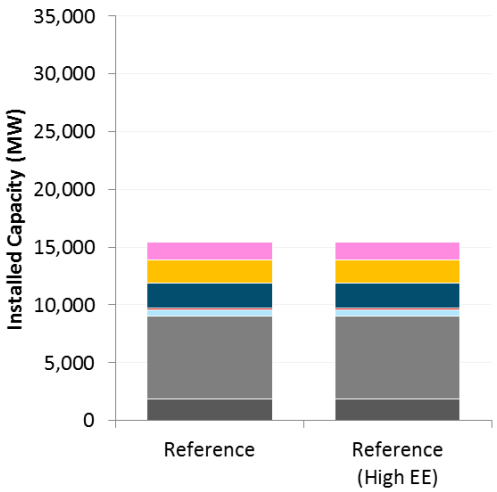
Reference Case (High EE Potential)

Highlights

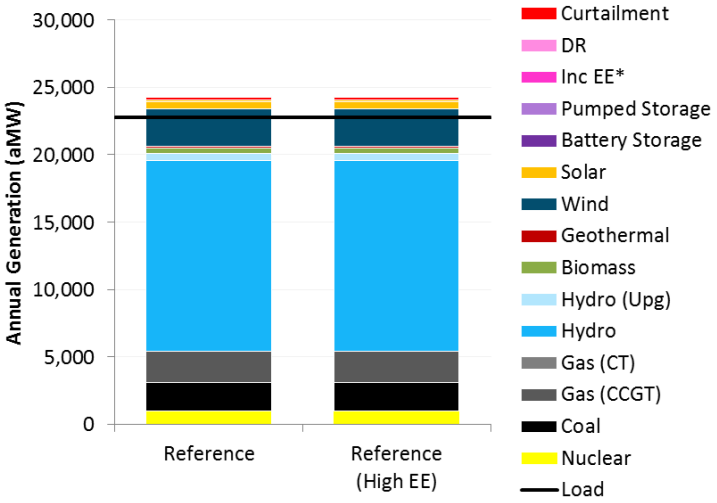
- Additional EE potential at $110/MWh is not selected in the Reference Case

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	—	—	20%	91%
High EE	—	—	20%	91%
Delta	—	—	—	—

Selected Resources (MW)



Energy Balance (aMW)



* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

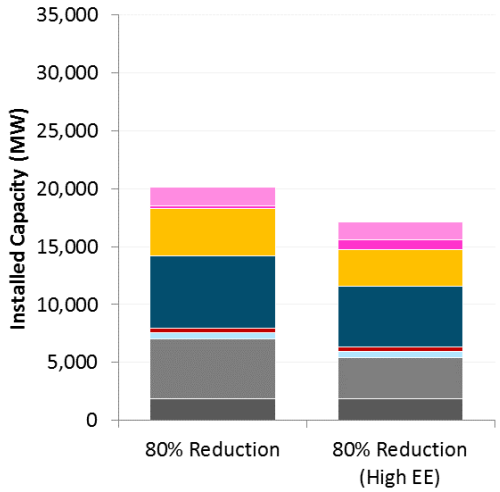
2050 Portfolio Summary
80% Reduction (High EE Potential)

Highlights

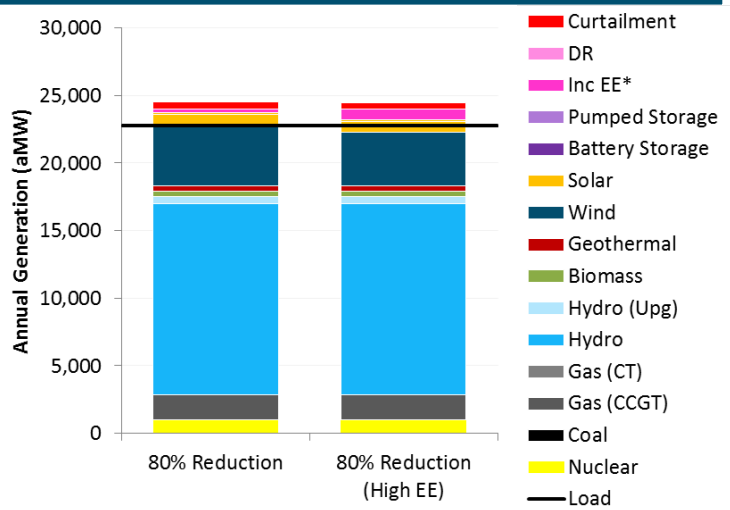
- An additional 600 aMW of EE is selected, reducing renewable build by 2,000 MW and thermal build by 1,500 MW

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	+1,046	20.9	31%	102%
High EE	+$908	20.9	28%	99%
Delta	-$138	—	-3%	-3%

Selected Resources (MW)



Energy Balance (aMW)

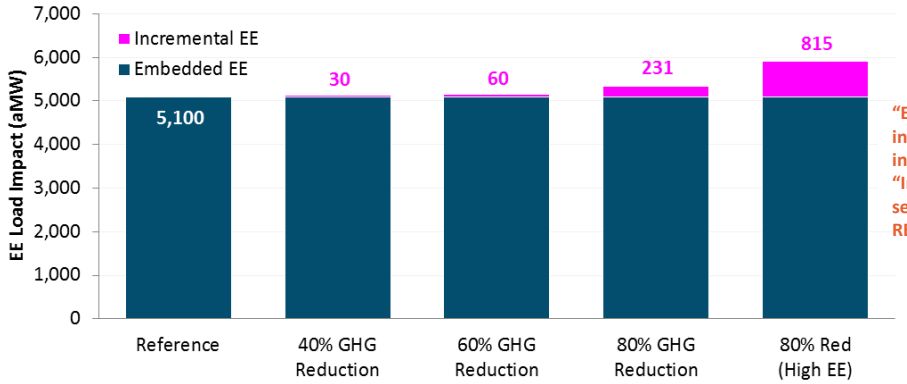


* EE shown here is incremental to efficiency i in load forecast (based on NWPCC 7th Plan)

Implications for Future Energy Efficiency Programs

- **Energy efficiency contributes toward meeting policy goals under a carbon pricing system**
  - RPS policy hinders the development of new energy efficiency due to low market pricing
- **Additional R&D is needed to identify new technologies and measures that may be cost-effective in future under GHG constraints**

Total 2050 Energy Efficiency Load Impact Across Multiple Scenarios (aMW)



"Embedded EE" is assumed in all cases and is included in the demand forecast; "Incremental EE" is selected by optimization in RESOLVE

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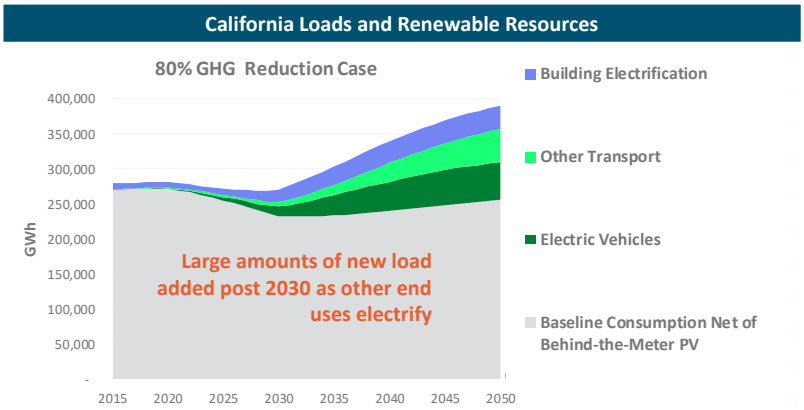
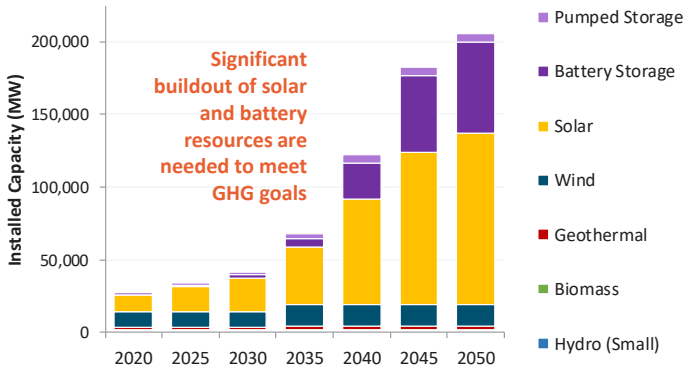
SENSITIVITY RESULTS

High California RPS

Sensitivity Overview
California 100% RPS





E3 tested the impact of a California 80% GHG reduction scenario on NW buildout and costs associated with meeting GHG goals:

- Increased California loads due to electrification of transportation and buildings
- 100% RPS policy in California (including existing hydro & nuclear)

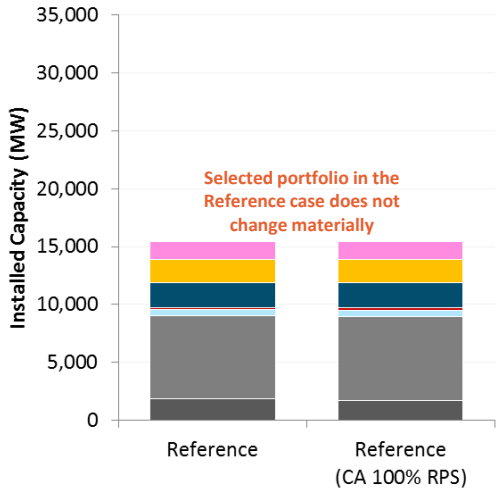
+ Changes in California policy result in: (1) more frequent curtailment and negative pricing in California; and (2) more volatility in wholesale markets

2050 Portfolio Summary
Reference Case (CA 100% RPS)

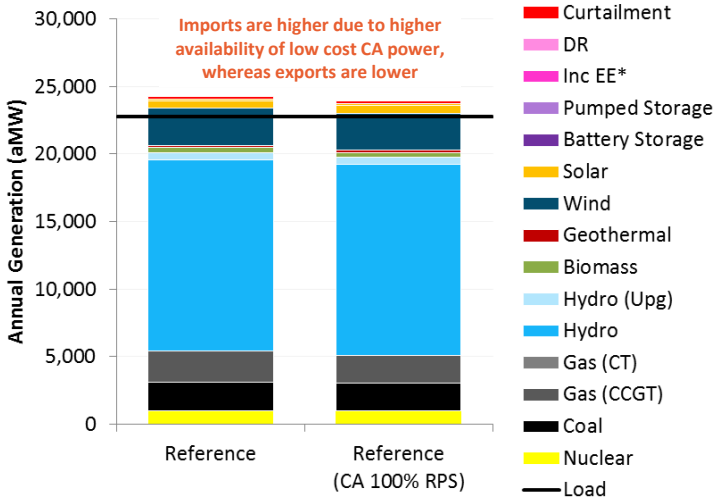
Highlights
- A 100% RPS in CA increases costs but has a limited impact on the portfolio in the Reference Case
- Slight increase in imports due to negative power prices in CA

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	—	6.7	20%	91%
CA 100% RPS	+$216	6.7	20%	91%
Delta	+$216	—	—	—

Selected Resources (MW)



Energy Balance (aMW)



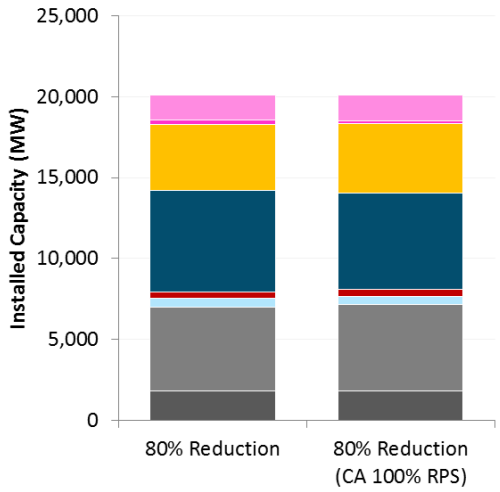
* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

2050 Portfolio Summary
80% Reduction Case (CA 100% RPS)

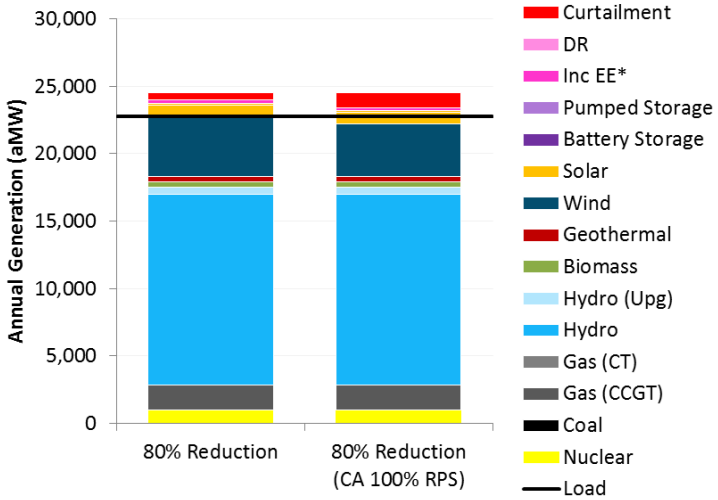
Highlights
- Limited impact on new resources
- Major impact is an increase in renewable curtailment, as the market for exports to California decreases with high CA RPS

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	+$1,046	20.9	31%	102%
CA 100% RPS	+$1,266	20.9	29%	99%
Delta	+$220	—	-2%	-3%

Selected Resources (MW)



Energy Balance (aMW)



* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

Implications of California Policy

- **Primary impact of California's increasing renewable goals is a reduction in the size of the potential export market for the Northwest—particularly during hydro runoff**
  - Increases likelihood of oversupply & renewable curtailment
- **Reduction in secondary revenues increases costs in the Northwest—under both Reference Case and GHG Reduction cases**
- **While not directly modeled, increased renewable goals in California could also create additional market opportunities for Northwest entities (i.e. flexible capacity payments, EIM revenues) if proper arrangements are made**

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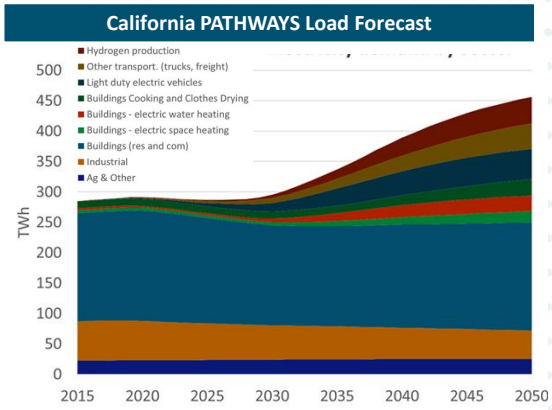
SENSITIVITY RESULTS

High Electric Vehicles

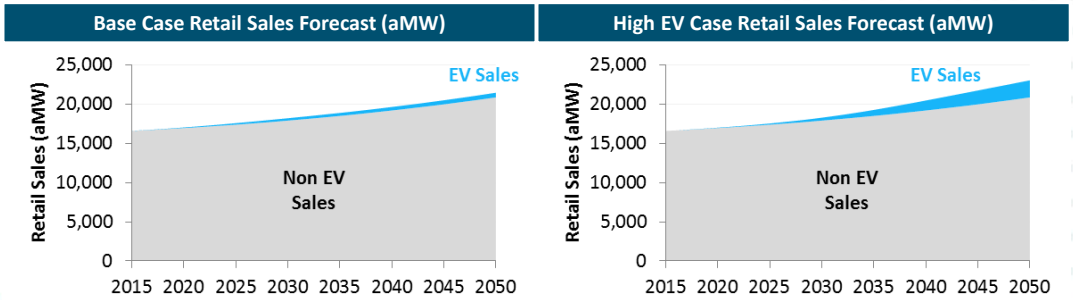
Role of Electrification in Meeting Economy-Wide Carbon Goals

- **Across multiple studies of long-term carbon goals, electrification of transportation and buildings is consistently identified as a key strategy to meeting long-term carbon goals:**
  - **Deep Decarbonization Pathways Analysis for Washington State** (Evolved Energy Research)
  - **Pathways to Deep Decarbonization in the United States** (E3/LBNL/PNNL)
  - **California PATHWAYS: GHG Scenario Results** (E3)
- **Long-term scenario planning identifies potentially significant increase in load as a result**



Overview of High EV Sensitivity

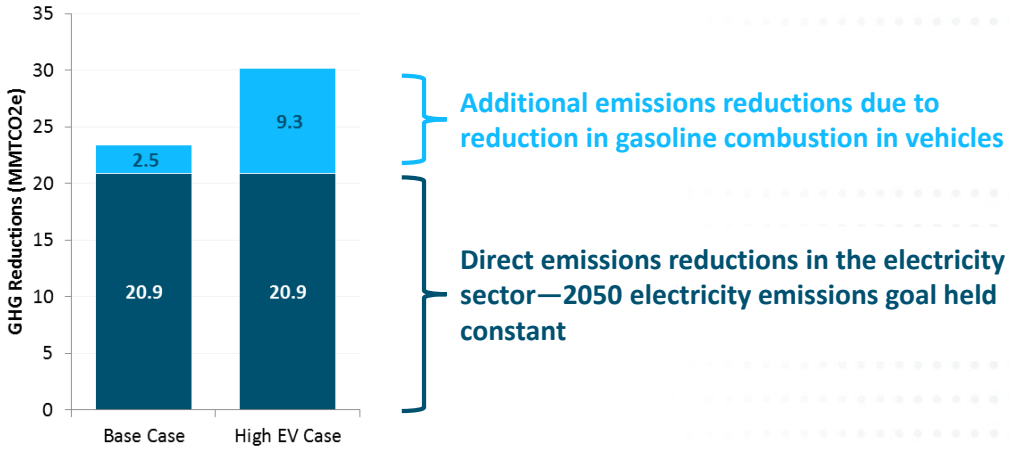
- **To explore interactions between electricity and other sectors in the Northwest, this sensitivity tests impact of adding 1,700 aMW of additional new transportation electrification load by 2050**
  - Total light-duty vehicle fleet: 5 million vehicles by 2050; **+3.5 million increase** relative to Base Case
  - Incremental GHG reduction in transportation sector: +**7 million metric tons**
- **Analysis addresses two questions:**
  - What is the cost of meeting incremental loads in the electric sector?
  - What is the **total resource cost** of electric vehicles for carbon abatement?



Greenhouse Gas Impacts
High EV Sensitivity

+ **Electrification of vehicles (and potentially other end uses) provides another mechanism for the electricity sector to contribute to meeting economy-wide decarbonization goals**

2050 Economy-Wide Emissions Reductions (MMTCO2e)



Costs & Benefits of EV Adoption

+ **Impacts of electric vehicle adoption span beyond the electricity sector, and cost-effectiveness is sensitive to factors external to electricity industry**
  - **Gasoline prices** (analysis assumes $3.12/gal in 2030 and $4.35/gal in 2050)
  - **Incremental vehicle capacity cost** (analysis assumes incremental cost has decreased to zero by 2050)

Item	Category	
Energy & Capacity Cost	Cost	→ Evaluated by RESOLVE
Incremental Vehicle Cost	Cost	Estimated outside of RESOLVE
T&D Cost	Cost	Estimated outside of RESOLVE
Charger Cost	Cost	Estimated outside of RESOLVE
Avoided Gasoline Purchases	Benefit	Estimated outside of RESOLVE
Avoided Vehicle O&M	Benefit	Estimated outside of RESOLVE

2050 Portfolio Summary
80% Reduction (High EV Adoption)

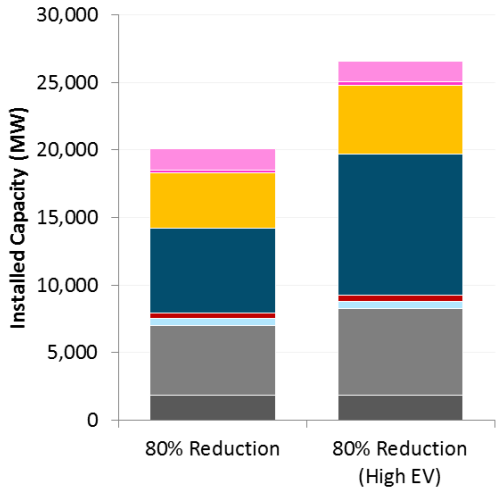
Highlights

- New electrification load stimulates additional investment in renewables & storage—5 GW of additional wind and solar relative to Base Case

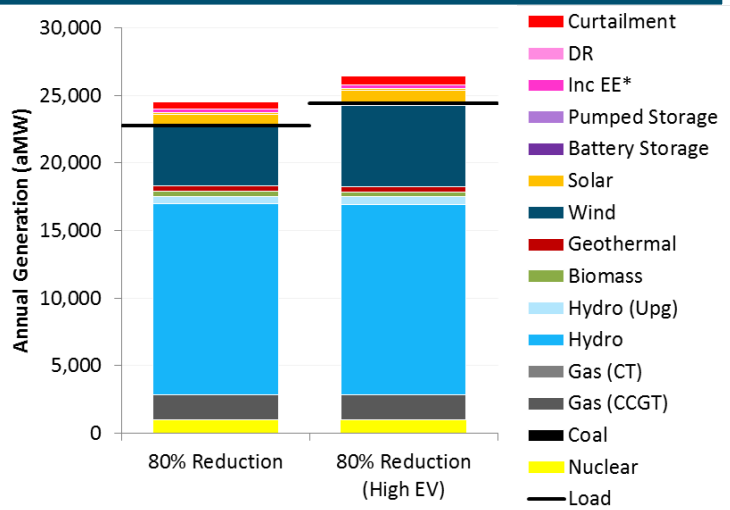
Scenario	Inc Cost* ($MM/yr.)	GHG Reductions* (MMT)	Effective RPS %	Zero CO2 %
Base	+$1,046	20.9	31%	102%
High EV	+$2,498	20.9	37%	103%
Delta	+$1,452	—	+6%	+1%

* Costs and GHG results reflect only the impact on the electric sector

Selected Resources (MW)



Energy Balance (aMW)

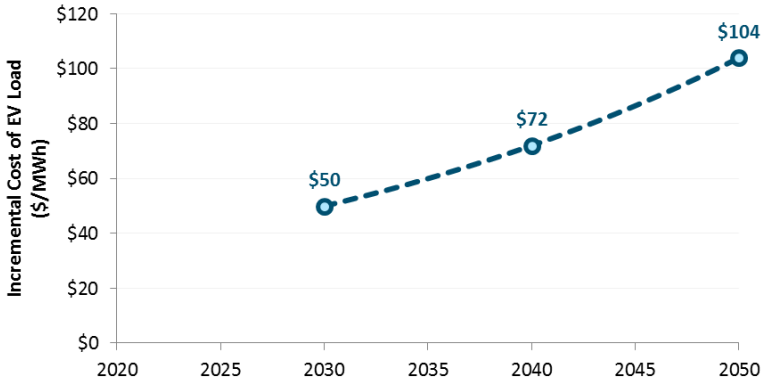


* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

Cost to Supply EV Loads

+ The cost to supply EV loads with carbon-free power increases through time as the system becomes increasingly greenhouse gas constrained

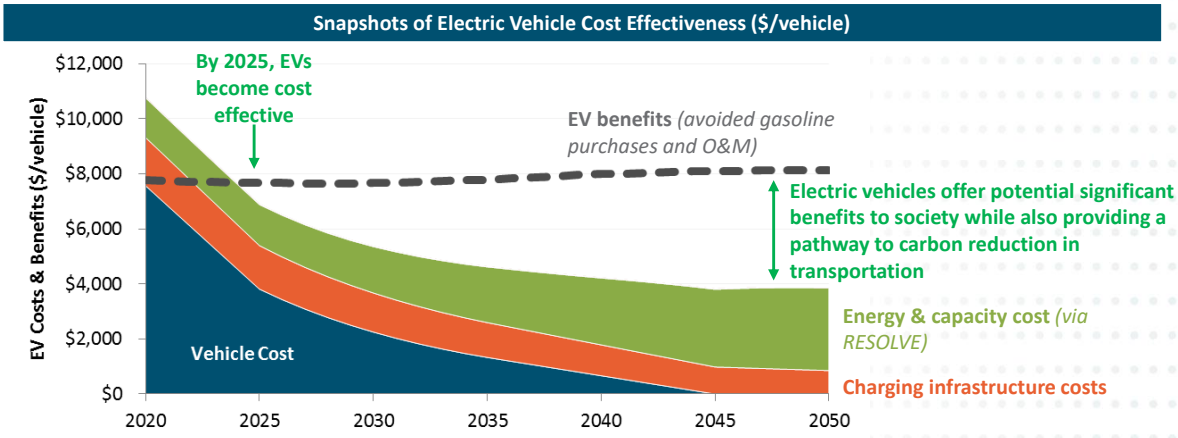
Incremental Cost to Meet EV Loads ($/MWh)



As system becomes constrained on greenhouse gases, cost to supply loads increases

Comparison of Total Resource Costs & Benefits

- **Despite increasing cost to supply energy and capacity, electric vehicles provide net TRC benefits in all years beyond 2030—implying a negative cost of carbon abatement**
  - **-$117/ton** in 2030
  - **-$291/ton** in 2050
- **While not cost-effective at today's vehicle prices, long-term support for adoption of electric vehicles is a potential low-hanging fruit to achieve economy-wide carbon reductions**



Implications for Electrification

- **Transportation electrification appears to be a promising strategy for furthering regional greenhouse gas goals**
  - Significant greenhouse gas reduction potential
  - Long-term net benefits to society, even ignoring GHG savings
- **With current high costs of electric vehicles, policy support may be needed initially to encourage adoption and ensure adequate supporting infrastructure**
  - General agreement in industry that vehicle costs will decrease rapidly and eventually reach parity with gasoline vehicles
- **Electrification of transportation and buildings requires more renewable development under a GHG policy framework**
  - Under a GHG policy, renewables are added to meet 100% of the new electrification energy requirements
  - Under an RPS policy, renewables are added only up to the specified RPS %

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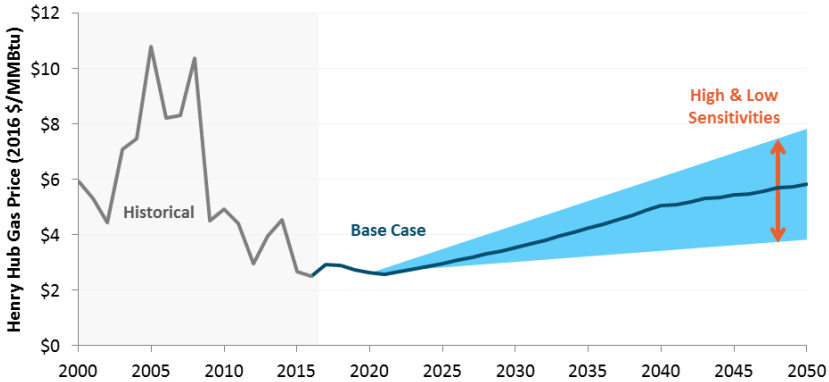
SENSITIVITY RESULTS

High & Low Gas Prices

Gas Price Sensitivity

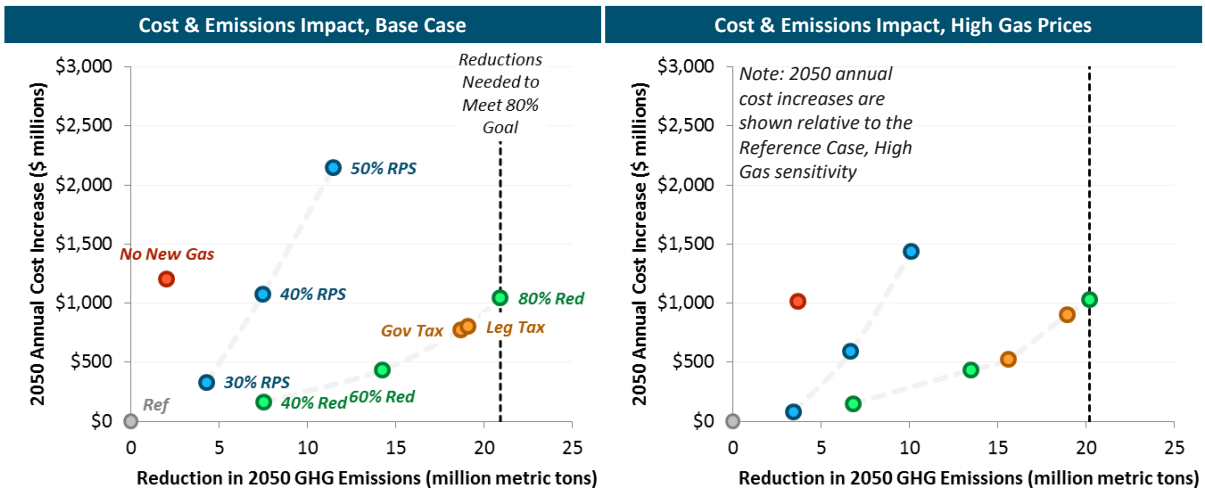
- **Future cost of natural gas is a key uncertainty; analysis high and low gas price forecasts demonstrates sensitivities of key results to this assumption**
- **All "Core Policy Scenarios" simulated with high and low gas prices (+/- 2/MMBtu relative to Base Case in 2050) to highlight how directional relationships among scenarios change**

Range of Long-Term Gas Price Forecasts Studied



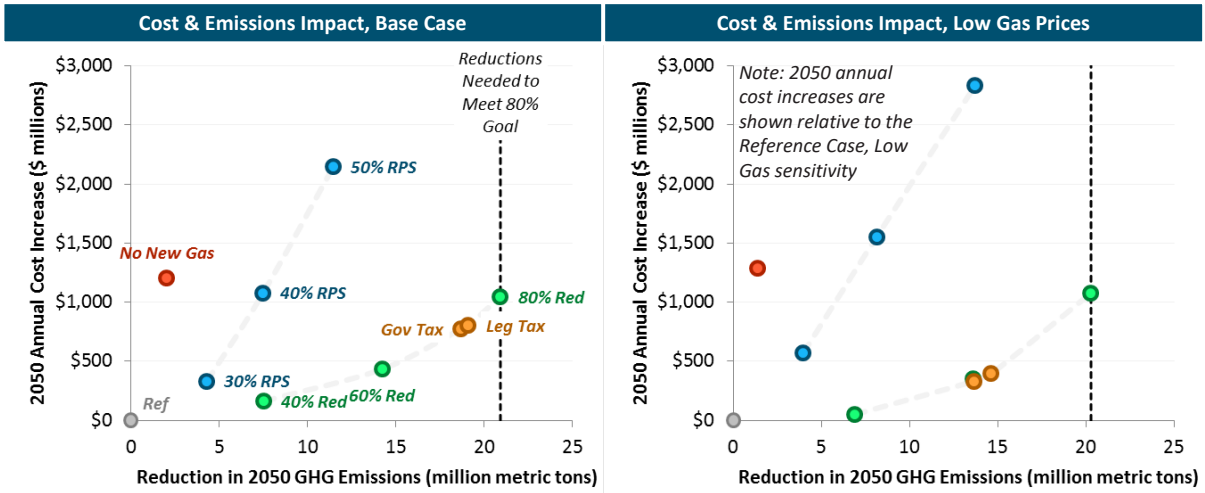
Cost & Emissions Impact
High Gas Price Sensitivity

+ **High Gas Price sensitivity reduces the cost of meeting high RPS targets, but has little impact on the cost of meeting greenhouse gas goals**



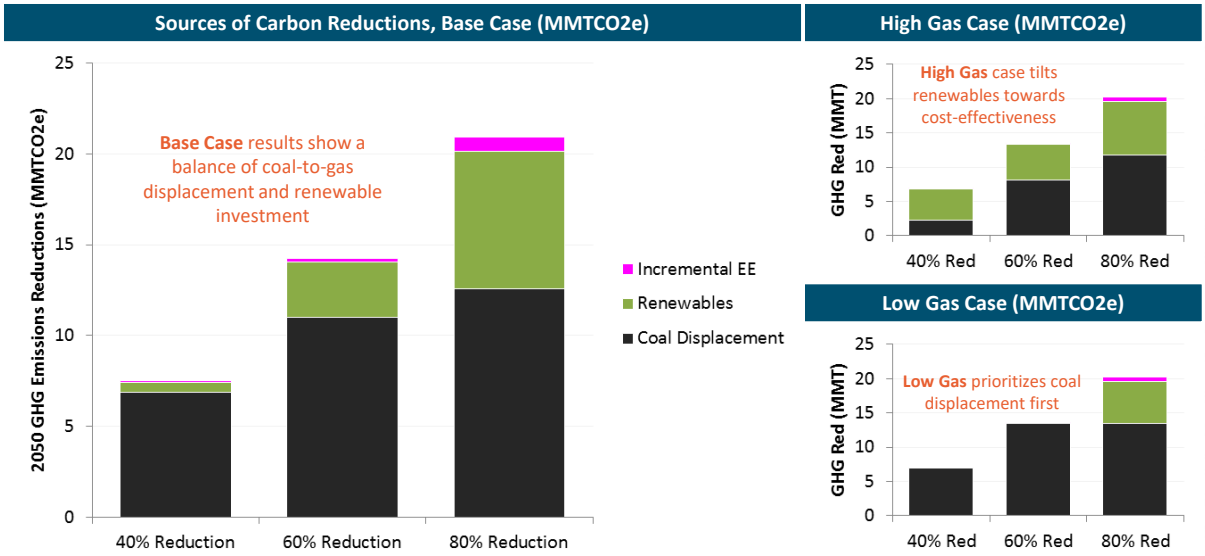
Cost & Emissions Impact
Low Gas Price Sensitivity

+ **Low Gas Price sensitivity results in substantial additional costs to meet higher RPS goals, but has little impact on the cost of meeting GHG**



Sources of Carbon Reductions

+ **Gas price sensitivities highlight importance of a technology-neutral policy for GHG reductions, as least-cost measures for GHG abatement will depend on a range of factors**



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SENSITIVITY RESULTS

Low Technology Costs

Low Technology Cost Sensitivity

- **In the Low Technology Cost sensitivity, this study explores potential increased cost reductions for emerging technologies:**
  - **Solar PV and wind:** capital costs reduced by 20% relative to the Base Case
  - **Battery storage:** capital costs reduced by 45% relative to the Base Case
- **Sensitivity captures the potential impact of technological breakthrough on the optimal renewable portfolio for the Northwest**

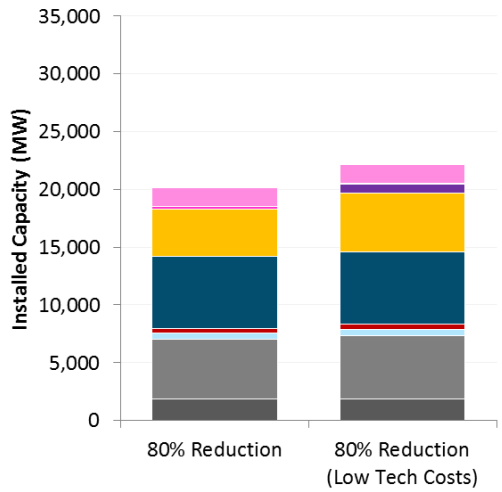
2050 Portfolio Summary

80% Reduction (Low Technology Costs)

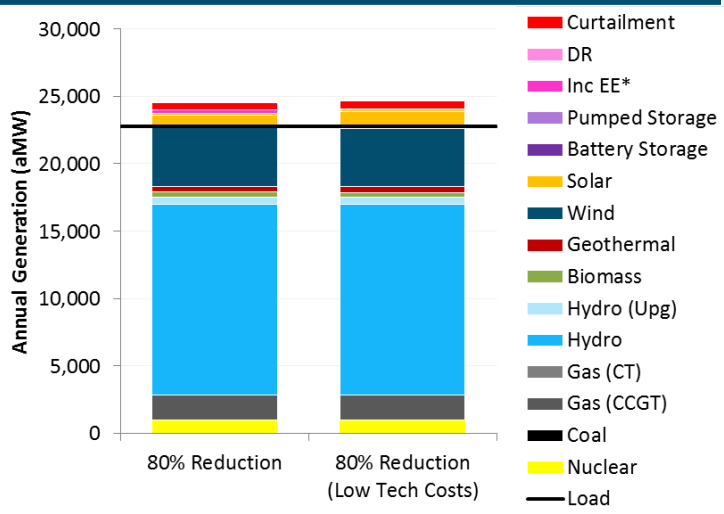
Highlights
- Portfolio shifts slightly towards solar PV + battery storage to meet clean energy needs
- Relative cost to achieve 80% reduction goal drops slightly

Scenario	Inc Cost ($MM/yr.)	GHG Reductions (MMT)	Effective RPS %	Zero CO2 %
Base	+$1,046	20.9	31%	102%
Low Tech Costs	+$900	20.9	32%	103%
Delta	-$146	—	+1%	+1%

Selected Resources (MW)



Energy Balance (aMW)

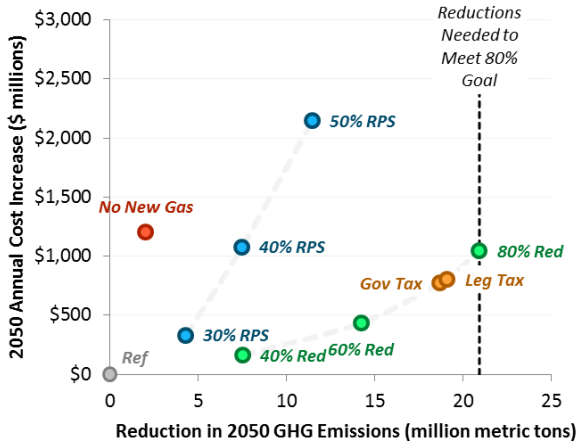


* EE shown here is incremental to efficiency included in load forecast (based on NWPCC 7th Plan)

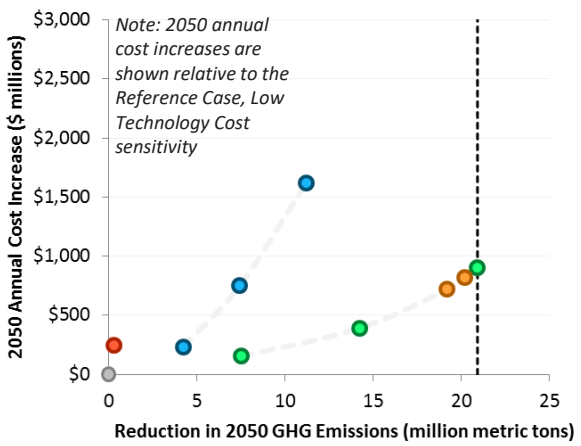
Cost & Emissions Impact
Low Technology Costs Sensitivity

- **Low technology cost sensitivity reduces cost of meeting RPS goals, as large investments in wind and solar are available at a lower cost**
- **Availability of low cost batteries reduces cost premium of No New Gas case—but greenhouse gas reductions are minimal**

Cost & Emissions Impact, Base Case



Cost & Emissions Impact, Low Technology Costs



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CONCLUSIONS & KEY FINDINGS

Key Findings (1 of 3)

1. **The most cost-effective opportunity for reducing carbon in the Northwest is to displace coal generation with a combination of energy efficiency, renewables and natural gas**
   - Coal generation produces approximately 80% of the Northwest's electricity-sector GHG emissions today
   - A technology-neutral policy that focuses on carbon provides incentives for leveraging the lowest-cost GHG emissions reductions
2. **Renewable generation is an important component of a low-carbon future, however a Renewables Portfolio Standard results in higher costs and higher carbon emissions than a policy that focuses directly on carbon**
   - RPS policy has been successful at driving investment in renewables but ignores other measures such as energy efficiency and coal displacement
   - RPS policy has unintended consequences such as oversupply and negative wholesale electricity prices that create challenges for reinvestment in existing zero-carbon resources

Key Findings (2 of 3)

3. **Prohibiting the construction of new natural gas generation adds significant cost but does little to save GHG emissions**
   - Older gas plants run at a higher capacity factor and generate more carbon emissions
   - More study is needed to determine whether the system modeled has sufficient energy and capacity to meet resource adequacy requirements
   - Building new gas resources for capacity is part of a least-cost portfolio even under carbon-constrained scenarios
4. **Meeting decarbonization goals becomes significantly more challenging and costly should existing zero-carbon resources retire**
   - Replacing 2,000 aMW of existing hydro or nuclear generation would require nearly 6,000 MW of new wind and solar generation and 2,000 MW of natural gas generation at an annual cost of $1.6 billion by 2050
   - A policy that encourages the retention of existing zero-carbon generation resources will help contain costs of meeting carbon goals

Key Findings (3 of 3)

5. **Returning revenues raised under a carbon pricing policy to the electricity sector is crucial to mitigate higher costs**
   - This is a common feature of carbon pricing programs adopted in other jurisdictions
   - This helps ensure that electricity ratepayers are not required to pay twice: first for the cost of investments in GHG abatement measures, and second for the emissions that remain
6. **Research and development is needed for the next generation of Energy Efficiency measures**
   - Higher-cost measures that have not traditionally been considered may become cost-effective in a carbon-constrained world
7. **Vehicle electrification is a low-cost measure for reducing carbon emissions in the transportation sector**
   - Electrification has benefits for society as a whole, but may increase costs in the electric sector

Next Steps

+ **This study considered many scenarios and sensitivities, however, additional research is indicated in the following areas:**

1. Economy-wide analysis of deep decarbonization pathways for the Pacific Northwest that examines the role of electric vehicles, building electrification, biofuels, hydrogen, and other potential GHG abatement measures
2. The role of natural gas in buildings and electric generation in meeting economy-wide GHG abatement goals
3. The role of energy storage in meeting capacity needs in a hydro-dominated region such as the Pacific Northwest, particularly under cases with restrictions on gas generation
4. The potential benefits of greater regional coordination in electricity system operations, renewable resource procurement, transmission planning and carbon allowance trading

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Thank You!

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APPENDIX 4: 2017 CONSERVATION POTENTIAL ASSESSMENT

Grant County County Public Utility District

2017 Conservation Potential Assessment Final Report

November 27, 2017

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

EES Consulting

November 27, 2017

Mr. Richard Cole
Grant County Public Utility District
30 C Street, SW
Ephrata, WA 98823

SUBJECT: 2017 Conservation Potential Assessment – Final Report

Dear Mr. Cole:

Please find attached a final report summarizing the 2017 Grant County Public Utility District (Grant PUD) Conservation Potential Assessment (CPA). This report covers the 20-year time period from 2018 through 2037. The measures and information used to develop Grant PUD's conservation potential incorporate the most current information available for Energy Independence Act (EIA) reporting. The near-term potential has increased from the 2015 CPA, largely due to improvements in LED technology and its increasing acceptance and adoption in the market. Over the 20-year study period, savings potential is down slightly.

We would like to acknowledge and thank you and your staff for the excellent support in developing and providing the baseline data for this project.

Best Regards,

Amber Nyquist
Senior Project Manager

Contents

Executive Summary

This report describes the methodology and results of the 2017 Conservation Potential Assessment (CPA) for Grant County Public Utility District (Grant PUD). This assessment provides estimates of energy savings by sector for the period 2018 to 2037. The assessment considers a wide range of conservation resources that are reliable, available and cost-effective within the 20-year planning period.

Background

Grant PUD provides electricity service to more than 46,930 customers in Grant County, Washington. Washington's Energy Independence Act (EIA), effective January 1, 2010 and modified October 4, 2016, requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utility-specific conservation potential assessment methodology.

The EIA sets forth specific requirements for setting, pursuing and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and

Conservation Council (Council) in developing the Seventh Power Plan. Thus, this Conservation Potential Assessment will support Grant PUD's compliance with EIA requirements.

This assessment was built on a new model based on the completed Seventh Power Plan, but utilizes the same methodology as previous Conservation Potential Assessments. However, the model was further updated to reflect changes since the completion of the Seventh Power Plan. The primary model updates included the following:

- Avoided Cost – recent forecast of wholesale power market prices, customized inputs as they apply to Grant PUD such as deferred capacity benefits, and included a range of prices for the social cost of carbon
- A peak hour definition specific to Grant PUD
- Customer Characteristics Data
  - New residential home counts
  - Updated commercial floor area
  - Updated industrial sector consumption

- Measure Updates
  - Updated measures from the Regional Technical Forum (RTF) subsequent to the development of the Seventh Power Plan
  - Revised/updated measure data for existing measures
  - Updated measure saturation data from the Council
- Improved modeling methodology that allows for measure opportunities not captured early in the study period to be achieved in subsequent replacement cycles
- Accounting for recent achievements in Grant PUD's programs

The first step of this assessment was to carefully define and update the planning assumptions using the current data and forecasts. The Base Case conditions were defined as the most likely market conditions over the planning horizon, and the conservation potential was estimated based on these assumptions. Additional scenarios were also developed to test a range of conditions and evaluate risk.

Results

Table ES-1 shows the high-level results of this assessment. The cost-effective potential by sector in 2, 6, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 42.52 aMW. The most important numbers per the EIA are the 10-year potential of 22.32 aMW, and the 2-year potential of 3.67 aMW.

Table ES-1
Cost Effective Potential - Base Case (aMW)

	2-Year*	6-Year	10-Year	20-Year
Residential	0.23	1.28	3.44	9.01
Commercial	0.47	2.31	5.22	12.86
Industrial	2.40	6.89	10.74	16.02
Agricultural	0.56	1.80	2.92	4.63
Total	**3.67**	**12.28**	**22.32**	**42.52**

**2018 and 2019*

These estimates include energy efficiency that could be achieved through Grant PUD's own utility programs and also through the utility's share of future momentum savings (defined as energy efficiency that occurs outside of utility programs). In addition, it is likely that some of the potential will be achieved through codes and standards, especially in the later years.

Energy efficiency also has the potential to reduce peak demands. Based on the hourly load profiles developed for the Seventh Power Plan and load data provided by Grant PUD, the reductions in peak demand provided by energy efficiency are summarized in Table ES-2 below. Grant PUD's annual peak typically occurs in winter evenings. In addition to these peak demand savings, demand savings would occur throughout the year.

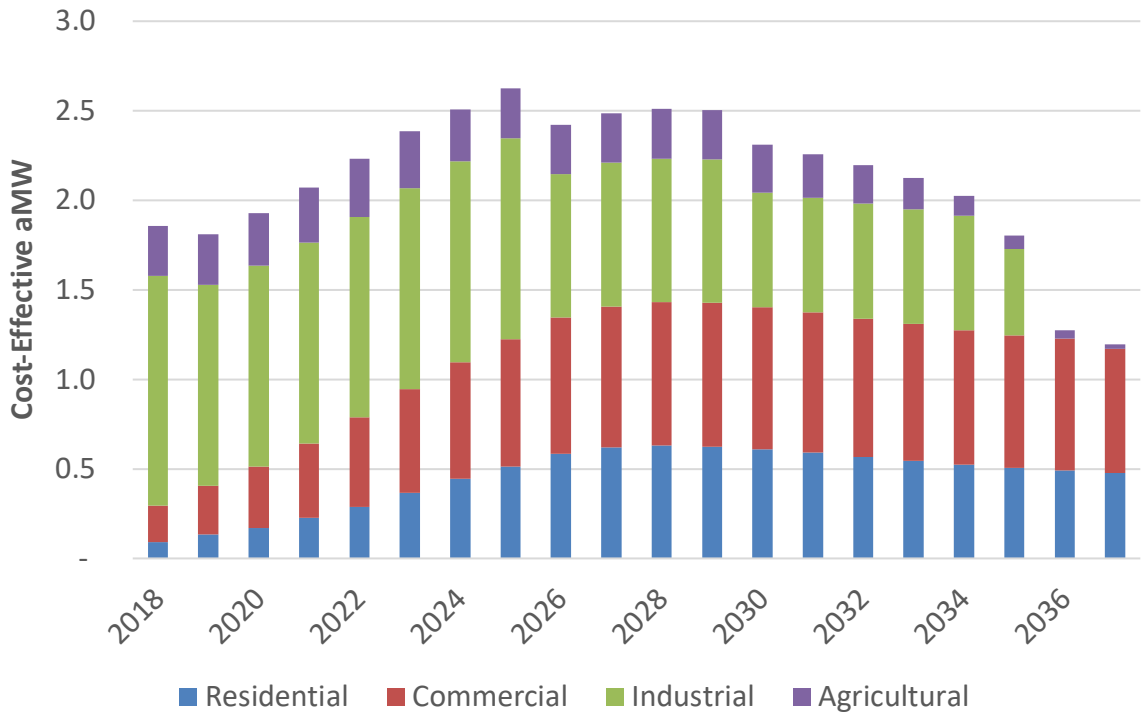
Table ES-2
Cost Effective Demand Savings - Base Case (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.82	4.19	10.26	22.96
Commercial	0.68	3.48	8.14	20.93
Industrial	2.66	7.63	11.89	17.74
Agricultural	0.06	0.14	0.19	0.24
Total	**4.22**	**15.44**	**30.47**	**61.88**

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-1. This assessment shows annual potential starting at 1.86 aMW in 2018 and ramping up to a maximum of 2.51 aMW in 2028. Potential gradually ramps down through the remaining years of the planning period. Ramp rates

from the Northwest Power and Conservation Council's (Council) Seventh Power Plan technical documentation were used to develop the annual savings potential over the 20-year study for the residential, commercial, and agriculture sectors. Some measures in these sectors were assigned lower ramp rates than what was used in the Seventh Power Plan to more closely match Grant PUD's recent program achievement levels. Industrial measures were assigned a custom ramp rate developed by EES. Compared with the Seventh Power Plan, the EES industrial ramp rate smooths potential out over a longer period of time. The EES ramp rate reflects Grant PUD's historic achievement patterns where large industrial projects are completed as both the PUD and the companies are able to budget for those projects. Historically, Grant PUD has saved an average of 1.05 aMW in the industrial sector (2012-2016).

Figure ES-1
Annual Cost-Effective Energy Efficiency Potential Estimates – Base Case Scenario



Within the residential sector, the savings potential is distributed among the main areas of residential energy consumption. Notable areas of potential include:

- HVAC-related measures, including weatherization and ductless heat pumps
- LED Lighting
- Water heating measures like heat pump water heaters and low-flow showerheads

The largest share of potential is available in Grant PUD's industrial sector. The notable areas for industrial potential include:

- Energy management measures, including Strategic Energy Management and the efficient operation of other motor-driven industrial systems
- Lighting – including high bay and other efficient lighting
- Refrigerated storage – including fruit, food and cold storage equipment tune-ups and retrofits

Significant potential is also available in the commercial sector. Commercial sector potential falls into the main categories of commercial energy usage: lighting and HVAC.

Comparison to Previous Assessment

Table ES-3 shows a comparison of 10 and 20-year Base Case conservation potential by customer sector for this assessment and the results of Grant PUD's 2015 CPA.

Table ES-3
Comparison of 2015 CPA and 2017 CPA Cost-Effective Potential

	10-Year			20-Year		
	2015	**2017**	**% Change**	**2015**	**2017**	**% Change**
Residential	5.38	3.44	-36%	12.63	9.01	-29%
Commercial	3.62	5.22	44%	5.34	12.86	141%
Industrial	10.69	10.74	0%	22.50	16.02	-29%
Agricultural	0.88	2.92	232%	2.89	4.63	60%
Total	**20.57**	**22.32**	**9%**	**43.36**	**42.52**	**-2%**

Notes:

1. Note that the 2015 columns refer to the CPA completed in 2015 for the time period of 2016 through 2035. The 2017 assessment is for the timeframe: 2018 through 2037.
2. Distribution system potential was not included in the 2015 or 2017 CPA. Grant PUD is unable to measure savings from DEI projects; therefore, DEI is excluded from both potential and achievement.

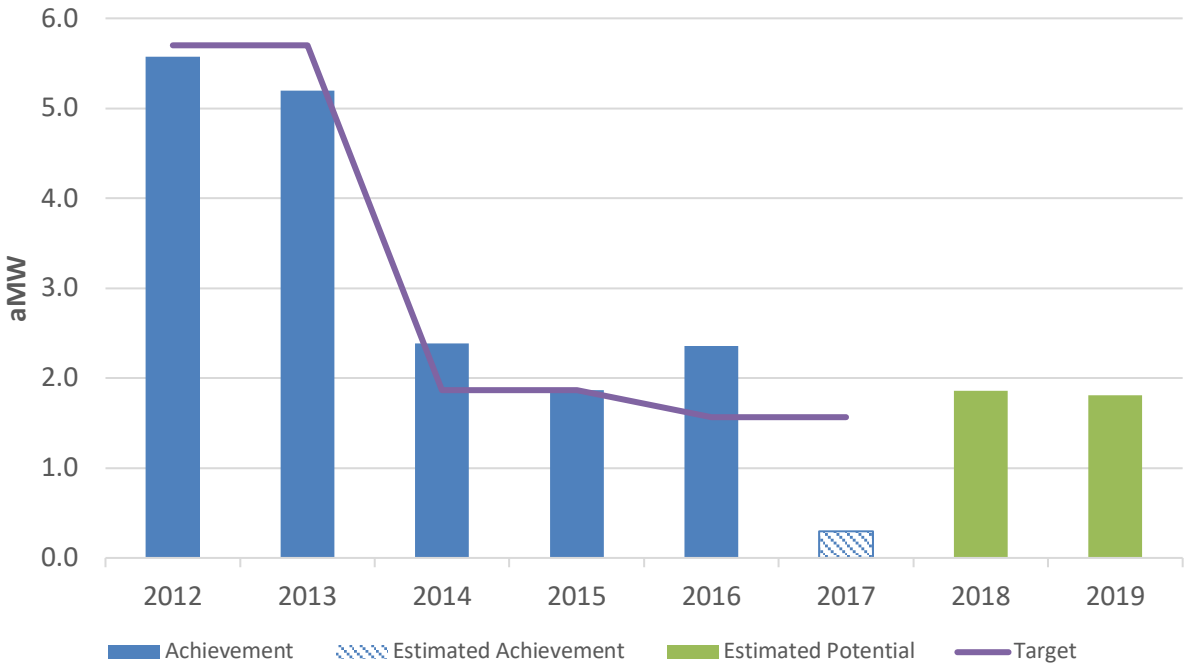
The results of this 2017 assessment are higher in the near term compared with the 2015 results. Despite lower energy market prices additional avoided cost components, now required under EIA rules, resulted in more measures being cost effective. Additionally, improvements in the performance and cost of key technologies like LED lighting and heat pump water heaters has led to increased potential.

Targets and Achievement

Figure ES-2 compares Grant PUD's historic conservation achievement with the 2017 CPA potential. The 2018 and 2019 potential estimates are based on the Base Case results of this assessment. With an average achievement of nearly 3.5 aMW per year between 2012 and 2016, the potential estimates for 2018-2019 of 1.83 aMW per year are achievable through Grant PUD's utility energy efficiency programs and Grant PUD's share of future Momentum savings.[1]

[1] Targets and potential shown in the figure are based on numbers reported to Washington State Department of Commerce. Note that savings significantly declined in 2014 due to a reduction in Scientific Irrigation Scheduling claimed by Grant PUD.

Figure ES-2
Historic Achievement and Targets



Summary

This report summarizes the CPA conducted for Grant PUD for the 2018 to 2037 timeframe. Based on the results of the Base Case scenario, the total 10-year cost effective potential is 22.32 aMW and the 2-year potential is 3.67 aMW.

Introduction

Objectives

The objective of this report is to describe the results of the Grant County Public Utility District (Grant PUD) 2017 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2018 to 2037, with the primary focus on 2018 to 2027 (10 years). This analysis has been conducted in a manner consistent with requirements set forth in 19.285 RCW (EIA) and 194-37 WAC (EIA implementation) and is part of Grant PUD's compliance documentation. The results and guidance presented in this report will also assist Grant PUD in strategic planning for its conservation programs in the near future. Finally, the resulting conservation supply curves can be used in Grant PUD's integrated resource plan (IRP).

The conservation measures used in this analysis are based on the most recent set of measures approved by the Regional Technical Forum (RTF) and are representative of the measures that will be used in the Council's Seventh Power Plan. The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

Electric Utility Resource Plan Requirements

According to Chapter 19.280 RCW, utilities with at least 25,000 customers are required to develop integrated resource plans (IRPs) by September 2008 and biennially thereafter. The legislation mandates that these resource plans include assessments of commercially available conservation and efficiency measures This CPA is designed to assist in meeting these requirements for conservation analyses. The results of this CPA may be used in the next IRP due to the state by September 1, 2018. More background information is provided below.

Energy Independence Act

Chapter 19.285 RCW, the Energy Independence Act, requires that, "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The timeline for requirements of the Energy Independence Act are detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document.
- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent ten years.
- By June 2012, each utility shall submit an annual conservation report to the department (the department of commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

This report summarizes the preliminary results of a comprehensive CPA conducted following the steps provided for a Utility Analysis. A checklist of how this analysis meets EIA requirements is included in Appendix III.

Study Uncertainties

The savings estimates presented in this study are subject to the uncertainties associated with the input data. This study utilized the best available data at the time of its development; however, the results of future studies will change as the planning environment evolves. Specific areas of uncertainty include the following:

- Customer characteristic data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that Grant PUD's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market price forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, risk credits are included in the analysis to mitigate the market price risk over the study period.
- Utility system assumptions – Credits have been included in this analysis to account for the avoided costs of bulk transmission and distribution system expansion and local distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits to be representative estimates of these avoided costs.
- Discount and finance rate – For this study, a discount rate specific to Grant PUD was used. Assumptions from the Seventh Plan about measure financing costs were also applied in the model. The Council develops a finance rate for each power plan based on the relative share of the costs of conservation and the cost of capital for the various program sponsors. The

Council has estimated these figures using the most current available information. While this study reflects current values for the discount and finance rates, changes in market rates will likely vary over the study period.

- Load and customer growth forecasts – The CPA bases the 20-year potential estimates on forecasted loads and customer growth. Each of these forecasts includes a level of uncertainty.
- Load shape data – The Council provides conservation load shapes for evaluating the timing of energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. This assessment uses the hourly load shapes used in the Seventh Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, under the EIA, qualifying utilities must update their CPAs every two years to reflect the best available information.

Report Organization

The main report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – Grant PUD's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy savings and costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary
- Appendices

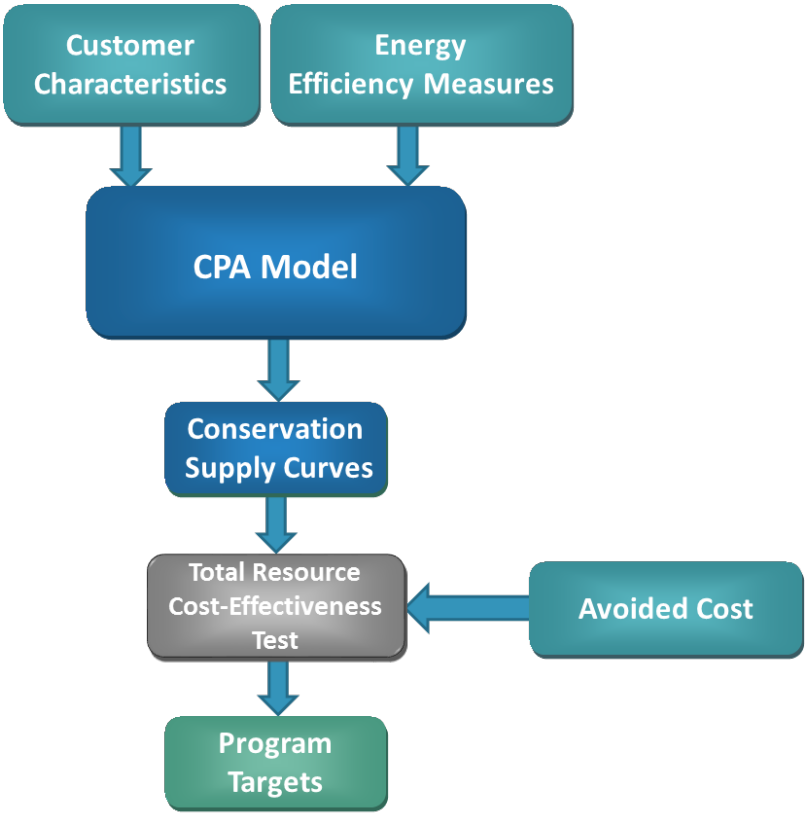
CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in Grant PUD's service area. The methodology complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. This section provides a broad overview of the methodology used to develop Grant PUD's conservation potential estimates. Specific assumptions and methodology as it pertains to compliance with the EIA is provided in the appendix of this report.

Basic Modeling Methodology

The basic methodology used for this assessment is illustrated in Figure 1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure are then aggregated to produce the total potential. The detailed methodology summary that follows the EIA requirements is listed in Appendix III.

Figure 1
Conservation Potential Assessment Process



Building Characteristic Data

The quantification of energy efficiency begins with compiling customer characteristics, baseline measure saturation data, and appliance saturation. For this analysis, the characterization of Grant PUD's baseline was determined based on information provided by Grant PUD's staff, NEEA's commercial and residential building stock assessments, and census data. Details of data sources and assumptions are described for each sector later in the report. Details of data sources and assumptions are discussed for each sector later in the report.

This assessment primarily sourced baseline measure saturation data from the Council's Seventh Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments,

studies, market research and other sources. Historic conservation achievement data was used to update measure saturation levels where applicable. EES adjusted measure saturation levels, using Grant PUD's conservation achievement history, for those measures with saturations that have not been updated since the 2011 Residential Building Stock Assessment. Grant PUD's historic achievement is discussed in detail in the next section.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs, and measure life (years). Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's Seventh Power Plan is the primary source for conservation measure data. Where appropriate, the Council's Seventh Plan supply curve workbooks, have been updated to include any subsequent updates from the RTF.

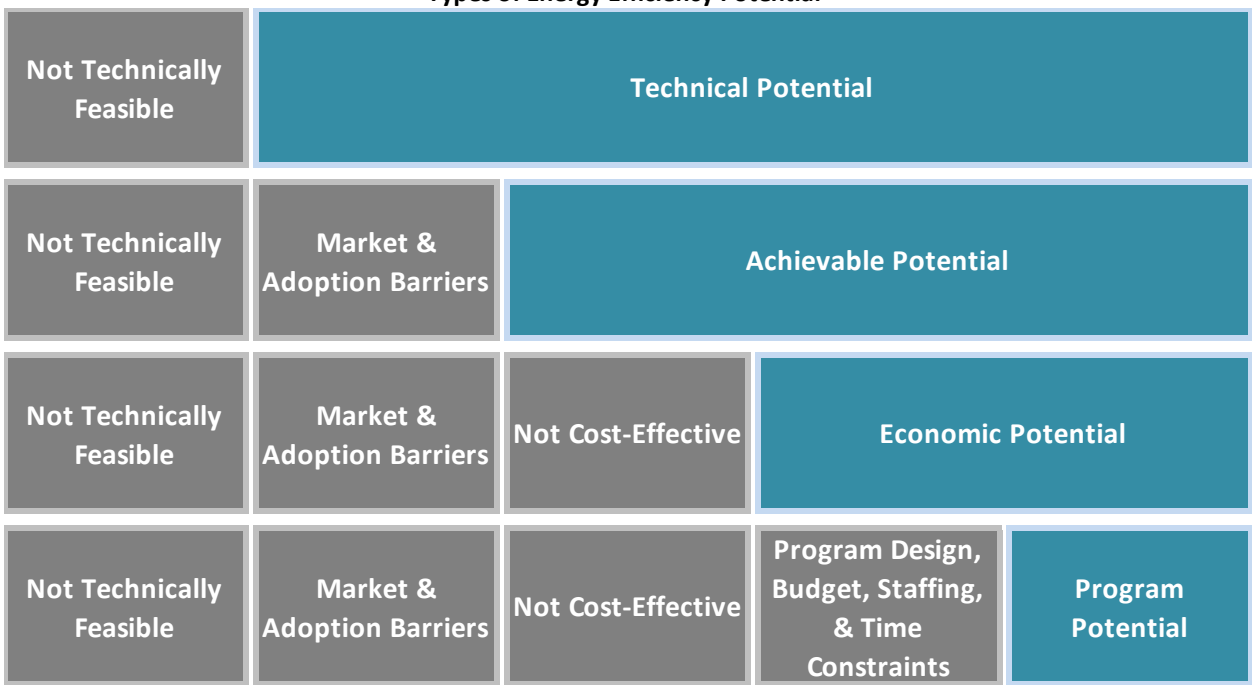
The measure data include adjustments from raw savings data for several factors. The effects of space-heating interaction, for example, are included for all lighting and appliance measures, where appropriate. For example, if an electrically-heated house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the electric heating system. These interaction factors are included in measure savings data to produce net energy savings. Other financial-related data needed for defining measure costs and benefits include: discount rate, avoided costs, line losses, and deferred capacity-expansion benefits.

A list of measures by end-use is included in this CPA is included in Appendix V.

Types of Potential

Three types of potential are used in this study: technical, achievable, and economic potential. Technical potential is the theoretical maximum efficiency in the service territory if cost and achievability barriers are excluded. There are physical barriers, market conditions, and other consumer acceptance constraints that reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the technical-achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 2 illustrates the four types of potential followed by more detailed explanations.

Figure 2
Types of Energy Efficiency Potential[2]



Technical – Technical potential is the amount of energy efficiency potential that is available, regardless of cost or other technological or market constraints, such as customer willingness to adopt measures. It represents the theoretical maximum amount of energy efficiency absent these constraints in a utility's service territory.

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Then, the number of "applicable units" must be estimated. "Applicable units" refers to the number of units that could technically be installed in a service territory. This includes accounting for units that may already be in place. The "applicability" value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A "saturation" factor accounts for measures that have already been completed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, if a home installs energy efficient lighting, the demands on the heating system will rise, due to a reduction in heat emitted by the lights (interaction). If a home installs both insulation and a high-efficiency heat pump, the total savings in the home is less than if each measure were installed individually (stacking). Interaction is addressed by accounting for impacts on other energy uses. Stacking is often addressed by considering the savings of each measure as if it were installed after other measures that impact the same end use.

The total technical potential is often significantly more than the amount of achievable and economic potential. The difference between technical potential and achievable potential is a result of the number of measures assumed to be unaffected by market barriers. Economic potential is further limited due to the number of measures in the achievable potential that are not cost-effective.

Achievable – Achievable potential is the amount of potential that can be achieved with a given set of conditions. Achievable potential takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include market availability of technology, non-measure costs, and physical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure. The Council uses achievability rates

[2] Reproduced from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency.* Figure 2-1, November 2007

equal to 85% for all measures over the 20-year study period. This is a consequence of a pilot program offered in Hood River, Oregon where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes. The Council also uses a variety of ramp rates to estimate the rate of achievement over time. This CPA follows the Council's methodology, including both the achievability and ramp rate assumptions. Note that the achievability factors are applied to the technical potential before the economic screening.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, the total resource cost test (TRC) is used to determine economic potential (per EIA requirements). This means that the present value of the benefits exceeds the present value of the costs over the lifetime of the measure. TRC costs include the incremental costs and benefits of the measure regardless of who pays a cost or receives the benefit. Costs and benefits include the following: capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Non-energy costs and benefits can be difficult to enumerate, yet non-energy costs are quantified where feasible and realistic. Examples of non-quantifiable benefits might include: added comfort and reduced road noise from better insulation, or increased real estate value from new windows. A quantifiable non-energy benefit might include reduced detergent costs or reduced water and sewer charges.

For this potential assessment, the Council's ProCost models are used to determine cost-effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2017 CPA evaluates measure savings on an hourly basis, but ultimately values the energy savings during two segments covering high and low load hour time periods.

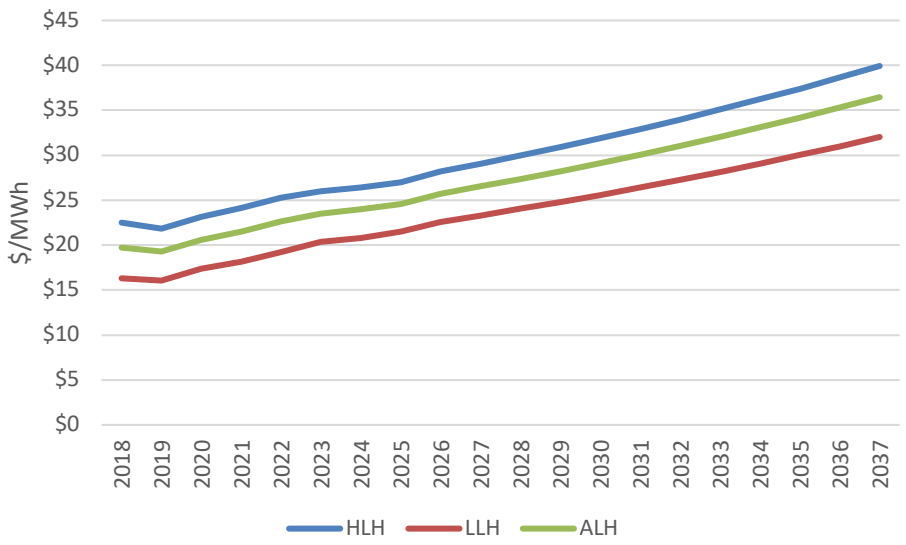
Program – Program potential is the amount of potential that can be achieved through utility administered programs. The program achievable potential excludes savings estimates that are achieved through future code changes and market transformation. The program potential is not the emphasis of this assessment, but understanding the sources of achievement is an important reporting requirement.

Avoided Cost

Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are generally included in the numerator in a benefit-cost test. The avoided cost input unit is dollars per MWh of energy or dollars per kW-yr for capacity-related savings. The primary component of the avoided cost of conservation is the forecast cost of an alternative resource, which may be based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the integrated resource planning process. However, for CPA analysis the EIA requires that utilities "…set avoided costs equal to a forecast of market prices."

Figure 3 shows the price forecast used for this assessment. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH). The market price forecast was provided by the utility and is used by the utility for power planning purposes. The levelized value of market prices over the study period is $26.10/MWh, assuming a 4 percent discount rate. The market forecast used for this assessment is 41 percent lower than the forecast used for the 2015 CPA. A primary driver of electricity prices (and forecasts) is the price of natural gas. The lower market price forecast used in this CPA is based on natural gas prices that are lower compared with the natural gas prices at the time the 2015 assessment was developed.

Figure 3
20-Year Market Price Forecast



Transmission and Distribution System Benefits

The EIA requires that deferred capacity expansion benefits for transmission, and distribution systems be included in the CPA cost-effectiveness analysis. To account for the value of deferred transmission and distribution system expansions, credits of $26/kW-yr and $31/kW-yr, respectively, were applied to peak savings from conservation measures. These values are consistent with the transmission and distribution credits developed by the Council for the Seventh Power Plan.

Generation Capacity

New to the Seventh Plan was the explicit calculation of a value for avoided generation capacity costs. Since the Northwest does not have an organized capacity market, the uncertainty of this value was addressed through a scenario analysis, where low, base, and high values were considered. For the base scenario, a three percent premium was added to market energy prices, which represents the premium value for capacity made available for sale through energy efficiency.

For the high scenario, the Council's value of $115/kW-yr was used. The Council reasoned that in pursuing energy efficiency, in each year it was deferring the cost of a generation unit to meet the region's capacity needs. Based upon the cost savings of deferring this cost for 30 years, the Council estimated a generation capacity value of $115/kW-year.

In the low scenario, it was assumed that spot market purchases would continue to be available to meet peak demands, and no value for generation capacity was assumed.

Risk Analysis

In the past, Grant PUD's CPAs have included risk mitigation credits in the scenario analysis to account for risks that were not quantified. Rather than including an explicit risk credit in each of the scenarios, this CPA addresses the uncertainty of the inputs by varying the avoided cost values. The avoided cost components that were varied included the energy prices, generation capacity value, and the social cost of carbon. Through the variance of these components, implied risk credits averaging $16/MWh and $115/kW-year were included in the high avoided cost scenario.

Additional information regarding the avoided cost forecast and risk mitigation credit values is included in Appendix IV.

Pacific Northwest Electric Power Planning and Conservation Act Credit

Finally, a 10 percent benefit was also added to measures per the Pacific Northwest Electric Power

Planning and Conservation Act and as required by the EIA.

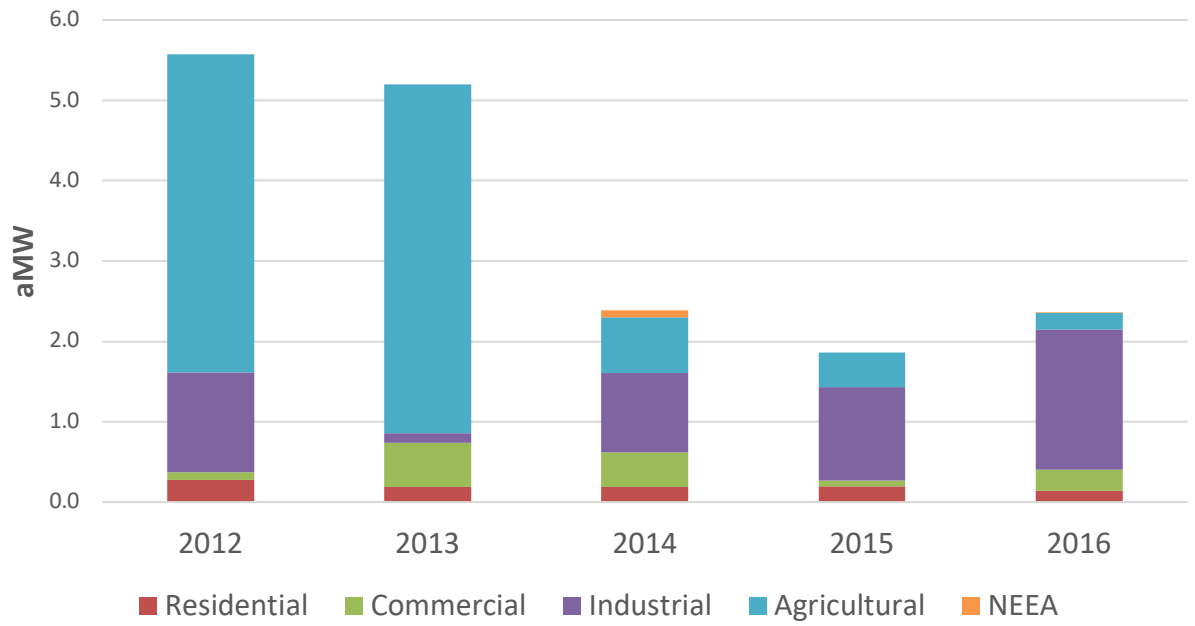
Discount and Finance Rate

The Council develops real discount rate assumptions for each of its Power Plans. The most recent real discount rate assumption developed by the Council is 4%, which was used in the Seventh Plan. This rate was used to model conservation potential for this assessment. The discount rate is used to convert future cost and benefit streams into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives. In addition, the Council uses a finance rate developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration, utilities, and customers. The second set of assumptions looks at the financing parameters for each of these entities to establish the after-tax average cost of capital for each group. These figures are then weighted, based on each group's assumed share of project cost to arrive at a composite finance rate.

Recent Conservation Achievement

Grant PUD has pursued conservation and energy efficiency resources for many years. Currently, the utility offers several rebate programs for both residential and non-residential applications. These include incentives for weatherization upgrades, appliances, new manufactured homes, heat pumps and ductless heat pumps, and custom projects. In addition to utility programs, Grant PUD has received credit for market-transformation activities that impact its service territory. These market-transformation activities are accomplished by the Northwest Energy Efficiency Alliance (NEEA). Figure 4 shows Grant PUD's conservation achievement from 2012 through 2016.

Figure 4
Grant PUD's Recent Conservation History by Sector

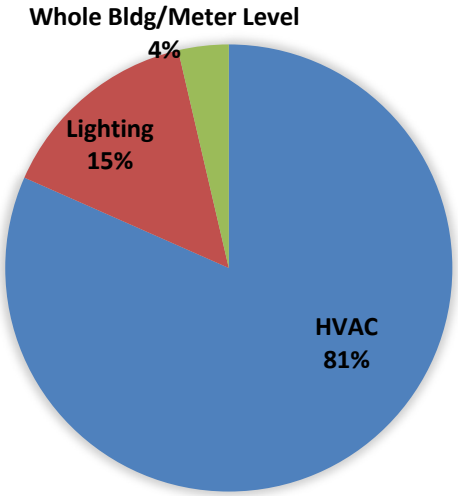


Grant PUD has achieved an average of 3.48 aMW of energy savings per year since 2012. This includes savings achieved through utility program efforts and NEEA savings. A large share of the 2012 and 2013 savings are from SIS measures in agriculture. The amount of savings Grant PUD could claim decreased in 2014 and a recent study conducted by BPA found that these measures no longer offer additional savings. Average annual savings excluding SIS have been 1.83 aMW since 2012. More detail on Grant PUD's utility program achievement is provided below for each customer sector.

Residential

Figure 5 shows recent conservation achievement by program in the residential sector. Due to the large share of electric heat in Grant PUD's service area, heating and weatherization measures account for about 81 percent of savings in the residential sector.

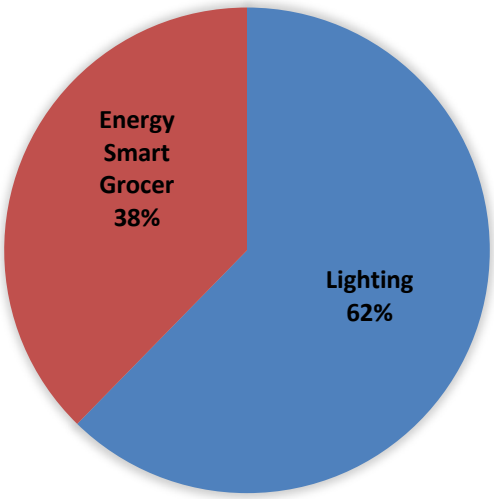
Figure 5
2015-2016 Residential Savings



Commercial

Historic achievement in the commercial sector is primarily due to lighting projects and the Energy Smart Grocer program. Figure 6 shows the breakdown of commercial sector achievement from 2015-2016.

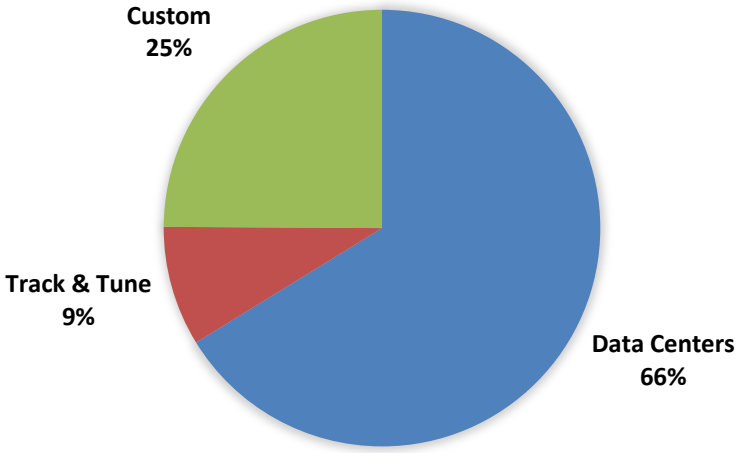
Figure 6
2015-2016 Commercial Savings



Industrial

Industrial achievement has been acquired through various custom projects, Track & Tune improvements, lighting, and Green Motor Rewinds. Savings from data centers are also claimed under the industrial sector in I-937 reporting. Figure 7 summarizes the industrial sector achievement 2015-16. Note that lighting and Green Motor rewinds have been omitted as they represent a very small fraction of industrial savings in this time period.

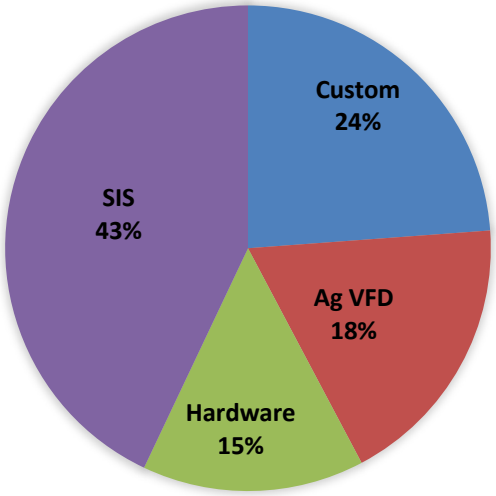
Figure 7
2015-2016 Industrial Savings



Agriculture

Agriculture program achievement has been acquired through SIS, irrigation hardware and custom system upgrades, as well as variable frequency drives (VFD). Figure 8 summarizes the agriculture sector achievement for the period 2015-2016. Note that SIS programs are not available going forward.

Figure 8
2015-2016 Agriculture Savings



Summary

Grant PUD plans to continue offering incentives for energy efficiency investments. The results of this study will assist Grant PUD program managers in strategic planning for energy efficiency program offerings, incentive levels, and program review.

Customer Characteristics Data

Grant PUD serves over 46,900 electric customers in Grant County, Washington, with a service area population of approximately 93,546. A key component of an energy efficiency assessment is to understand the characteristics of these customers – primarily the building and end-use characteristics. These characteristics for each customer class are described below.

Residential

For the residential sector, the key characteristics include house type and vintage distribution, space-heating fuel, and water heating fuel. Tables 1, 2 and 3 show relevant residential data for single family, multi-family and manufactured homes in Grant PUD's service territory. Residential characteristics are based on utility-provided data, census data for Grant County and regional data from the 2011 Residential Building Stock Assessment (RBSA) developed by NEEA. These data provide estimates of the current residential characteristics in Grant PUD's service territory and are utilized as the baseline in this study.

The unique characteristics of Grant PUD's service territory influence the amount and distribution of available conservation. In particular, potential for this study was impacted by the large share of electric space heating and water heating in the utility's service area. The distribution of Grant PUD's residential housing stock also impacted residential potential for this assessment.

This assessment assumes an average annual residential growth rate of 1.5 percent and uses the regional average annual demolition rate. The growth rate is based on utility estimates of residential growth.

Table 1
Residential Building Characteristics

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	35,970	93,546

Table 2 Existing Homes - Heating / Cooling System Saturations			
Electric Heat/Cooling System Saturations	**Single Family**	**Multifamily - Low Rise**	**Manufactured**
Electric Forced Air Furnace (FAF)	39%	2%	74%
Heat Pump (HP)	66%	0%	15%
Ductless HP (DHP)	0%	0%	0%
Electric Zonal (Baseboard)	48%	91%	5%
Central AC	48%	11%	11%
Room AC	14%	2%	3%

New Homes - Heating / Cooling System Saturations			
Electric Heat/Cooling System Saturations	**Single Family**	**Multifamily - Low Rise**	**Manufactured**
Electric Forced Air Furnace (FAF)	19%	2%	74%
Heat Pump (HP)	44%	0%	15%
Ductless HP (DHP)	0%	0%	0%
Electric Zonal (Baseboard)	34%	94%	5%
Central AC	48%	11%	11%
Room AC	14%	2%	3%

Table 3 Existing Homes - Appliance Saturations			
Appliance Saturation	**Single Family**	**Multifamily - Low Rise**	**Manufactured**
Electric WH	97%	97%	97%
Refrigerator	129%	103%	121%
Freezer	53%	4%	43%
Clothes Washer	99%	47%	99%
Clothes Dryer	98%	47%	95%
Dishwasher	89%	78%	77%
Electric Oven	75%	97%	90%
Desktop	96%	44%	71%
Laptop	68%	26%	42%
Monitor	102%	45%	72%

Table 3 (cont'd) New Homes - Appliance Saturations			
Appliance Saturation	**Single Family**	**Multifamily - Low Rise**	**Manufactured**
Electric WH	97%	97%	97%
Refrigerator	129%	103%	121%
Freezer	53%	4%	43%
Clothes Washer	99%	47%	99%
Clothes Dryer	98%	47%	95%
Dishwasher	89%	78%	77%
Electric Oven	75%	97%	90%
Desktop	96%	44%	71%
Laptop	68%	26%	42%
Monitor	102%	45%	72%

Commercial

Building square footage is the key parameter in determining conservation potential for the commercial sector since many of the measures are based on savings as a function of building area (kWh per square foot). Grant PUD provided 2016 MWh consumption for each of the 18 building categories shown in Table 4. Square footage for each category was calculated based on 2016 consumption and regional energy use intensity (EUI) values. The regional EUI values used for this assessment are based on data collected for the 2014 Commercial Building Stock Assessment (CBSA).[3] EUI units are kWh per square foot of building floor area.

Commercial square footage estimates for this assessment are approximately 4 million square feet higher than the adjusted 2014 commercial square footage used in the 2015 CPA. The higher commercial floor area estimates are a contributing factor to the increased commercial sector potential for this assessment, as compared to commercial potential estimated for the 2015 CPA. More detail regarding commercial sector potential is provided in the Results section of this report.

Regional growth rates by building type were adjusted to match utility-provided growth forecasts for the commercial rate class. The growth rates presented in Table 4 are net of commercial building demolition assumptions for Grant PUD's service territory. Demolition rates are based on Council assumptions.

[3] Navigant Consulting. 2014. *Northwest Commercial Building Stock Assessment: Final Report.* Portland, OR: Northwest Energy Efficiency Alliance.

Table 4 Commercial Building Square Footage by Segment			
Segment	**Area (Square Feet)**	**EUI (kWh/sf)***	**Net Growth Rate**
Large Office	115,977	15.9	1.2%
Medium Office	568,251	15.9	1.2%
Small Office	1,286,082	15.9	1.2%
Extra Large Retail	1,032,562	12.7	1.1%
Large Retail	1,049,786	12.7	1.1%
Medium Retail	456,822	12.7	1.1%
Small Retail	2,013,588	12.7	1.1%
K-12 Schools	3,863,115	9.77	1.1%
University	855,245	17.9	1.1%
Warehouse	18,275,087	5.46	1.6%
Supermarket	312,489	54.6	1.0%
Mini Mart	216,975	54.6	1.1%
Restaurant	477,807	44.1	1.2%
Lodging	1,901,792	14.3	1.0%
Hospital	997,169	23.7	1.1%
Residential Care	74,401	12.7	1.3%
Assembly Hall	1,451,355	14.5	1.2%
Other	9,032,043	11.6	1.0%
Total	43,980,545		**1.2%**

*NEEA 2014 Commercial Building Stock Assessment.

The Council includes data center savings potential in the commercial sector as the Seventh Plan analysis focuses on server room measures. Since Grant PUD data centers are large centralized loads, these are treated as industrial customers in the next section.

Industrial

The methodology for estimating industrial potential is different than approaches used for the residential and commercial sectors primarily because industrial energy efficiency opportunities are based on the distribution of electricity use among processes at industrial facilities. Industrial potential for this assessment was estimated based on the Council's "top-down" methodology that utilizes annual consumption by industrial segment and then disaggregates total electricity usage by process shares to create an end-use profile for each segment. Estimated measure savings are applied to each sector's process shares.

Grant PUD provided 2016 energy use for its industrial customers. Individual industrial customer usage is summed by industrial segment in Table 5. The 2016 industrial sector consumption totaled 1,658 GWh compared with 1,506 GWh in 2012. Regional growth rates were revised based on estimated future growth.

Table 5 Industrial Sector Load by Segment		
Segment	**MWh**	**Annual Growth Rate**
Paper	15,196	1.6%
Foundries	23,910	2.0%
Frozen Food	259,514	1.0%
Other Food	98,778	1.8%

Table 5 Industrial Sector Load by Segment		
Segment	**MWh**	**Annual Growth Rate**
Electric Fabrication	760	0.0%
Silicon[1]	132,553	0.4%
Metal Fabrication	4,658	2.4%
Equipment	104,450	-0.5%
Cold Storage	12,480	3.5%
Fruit Storage	50,940	3.6%
Refinery	158,970	0.0%
Chemical	629,813	1.9%
Miscellaneous Manufacturing	166,234	2.4%
Total	**1,658,257**	**1.4%**

1. Includes one customer with two plants: one efficient plant and one older plant. Under normal business practices, the efficient plant operates most of the time and the older plant is the first to shut down when not needed.

The table above does not include data centers, which represent a large portion of Grant PUD's load and have been an occasional source of large amounts of savings. Through discussions with Grant PUD staff, it was determined the opportunities to work with these customers on energy efficiency generally occurs during construction, and typically on measures relating to the shell and mechanical systems. Many data center operators are intrinsically motivated to install energy efficient servers or their business model prevents such upgrades from happening after the start of operations. As such, of the measures applicable to data centers, only the measures relating to building shell and mechanical systems were included, and the opportunities were quantified based only on the forecasted growth of data centers.

Agriculture

To determine agriculture sector characteristics in Grant PUD's service territory, EES utilized Grant County data collected by the United States Department of Agriculture (USDA). The USDA conducts a census of farms and ranches in the U.S. every five years. The most recent available data for this analysis is from the 2012 census, which was published in 2014.[4]

Irrigated acreage of 428,200 acres was used for this assessment, consistent with the 2015 CPA. Dairy farms with a total of 28,103 cattle head was also used to quantify dairy farm potential. According to the 2012 Census, there are 1,146 farms in Grant PUD's service territory. The number of farms is used to determine potential for the new area lighting measure. Table 6 shows key agriculture sector characteristics and applicable data sourced from the 2012 Census.

Table 6 Agriculture Sector Inputs		
Agriculture Data	**Count**	**2012 Census Data Point**
Number of Farms	1,146	Total number of farms
Irrigated Acres	428,200	Irrigated land
Dairy Cows	28,103	Milk Cows

Conservation potential for Scientific Irrigation Scheduling (SIS) was excluded from this assessment. A review of savings conducted by the Bonneville Power Administration confirmed Grand PUD's findings that the measures are not cost-effective (no savings).

[4] United States Department of Agriculture. (2014). *2012 Census of Agriculture.* Retrieved from: http://www.agcensus.usda.gov/Publications/2012/

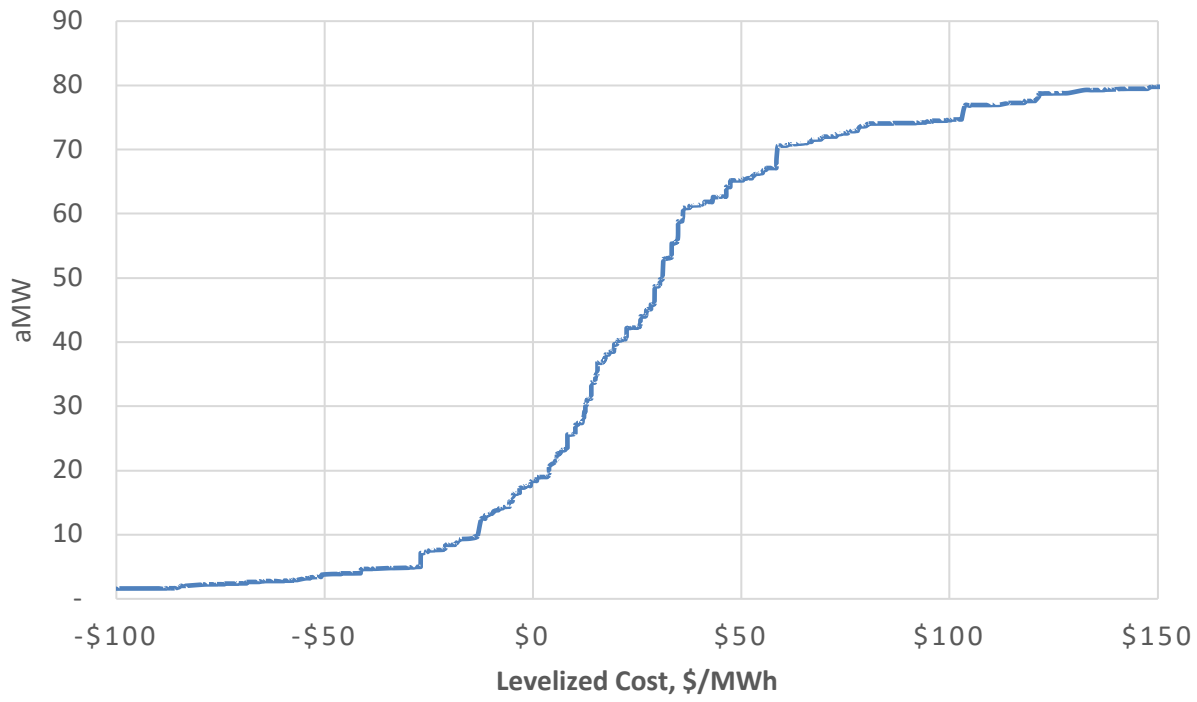
Results – Energy Savings and Costs

Achievable Conservation Potential

Achievable potential is the amount of energy efficiency potential that is available regardless of cost. It represents the theoretical maximum amount of achievable energy efficiency savings.

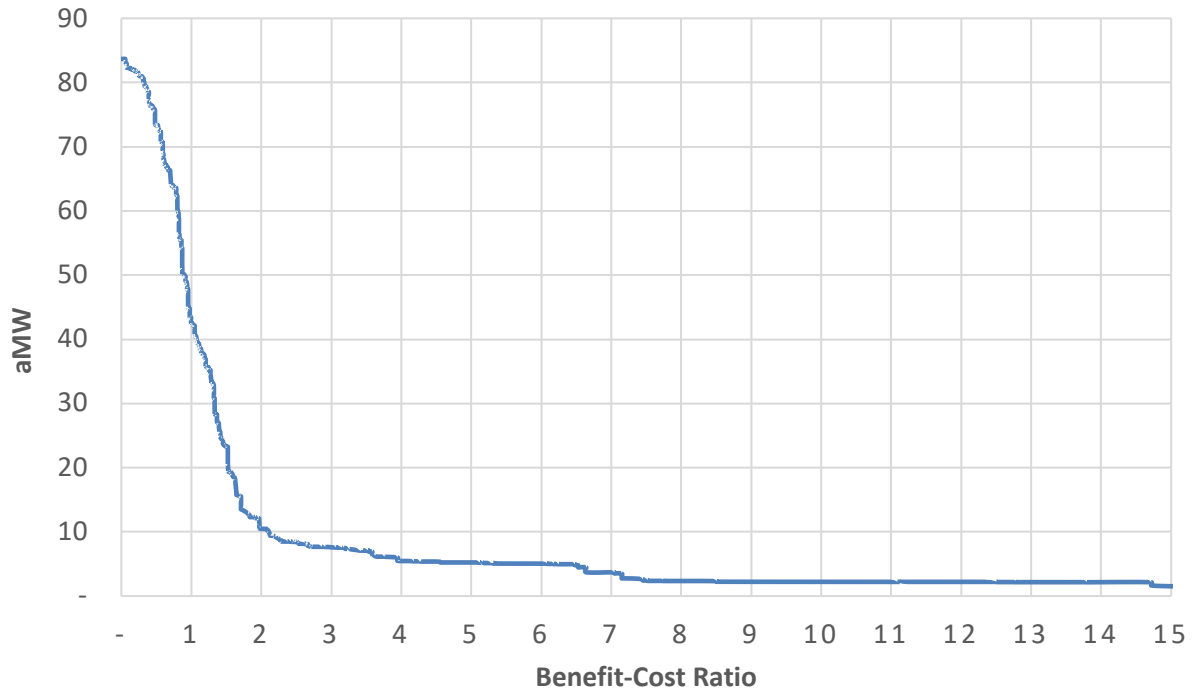
Figure 9, below, shows a supply curve of 20-year, technical-achievable potential. A supply curve is developed by plotting cumulative energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the conservation. The technical potential has not been screened for cost effectiveness. Costs are standardized (levelized), allowing for the comparison of measures with different lives. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with IRPs. Figure 9 shows that approximately 48.7 aMW of savings potential is available for less than $30/MWh and 81 aMW are available for under $80/MWh. Total technical-achievable potential for Grant PUD is approximately 73 aMW over the 20-year study period.

Figure 9
20-Year Achievable Potential Supply Curve



While useful for considering the costs of conservation measures, supply curves based on levelized cost are limited in that not all energy savings are equally valued. Another way to depict a supply curve is based on the benefit-cost ratio, as shown in Figure 10 below. This figure repeats the overall finding that approximately 42.5 aMW of potential is cost-effective with a benefit-cost ratio greater than or equal to 1.0. The potential rises and falls steeply on both sides of the line where the benefit-cost ratio equals 1.0, suggesting significant changes in potential if avoided cost parameters are changed in either direction.

Figure 10
20-Year Benefit-Cost Ratio Supply Curve



Economic Conservation Potential

Economic potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means the present value of the benefits attributed to the conservation measure exceeds the present value of the measure costs over its lifetime.

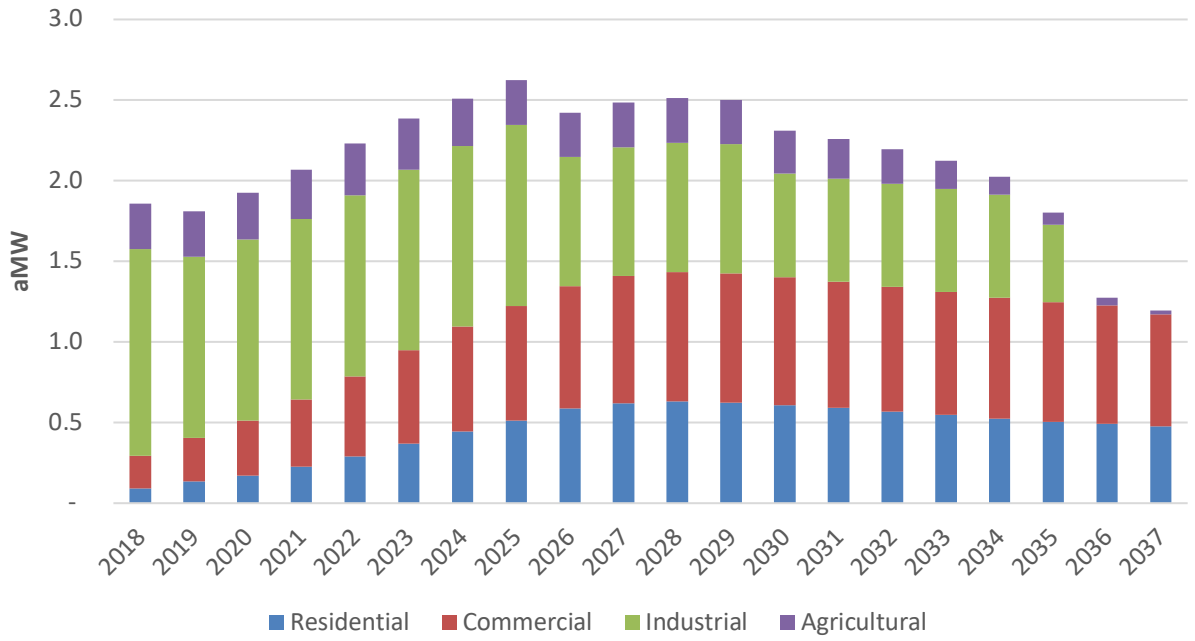
Table 7 shows aMW of economic (cost-effective) potential by sector in 2, 6, 10 and 20-year increments. Compared with the achievable potential, it shows that 42.52 aMW of the total 83.68 aMW is cost effective for Grant PUD (approximately 51 percent). The last section of this report discusses how these values could be used for setting targets.

Table 7 Cost Effective Achievable Potential - Base Case (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	0.23	1.28	3.44	9.01
Commercial	0.47	2.31	5.22	12.86
Industrial	2.40	6.89	10.74	16.02
Agricultural	0.56	1.80	2.92	4.63
Total	**3.67**	**12.28**	**22.32**	**42.52**

Sector Summary

Figure 11 shows economic achievable potential by sector on an annual basis.

Figure 11
Annual Cost-Effective Achievable Potential by Sector



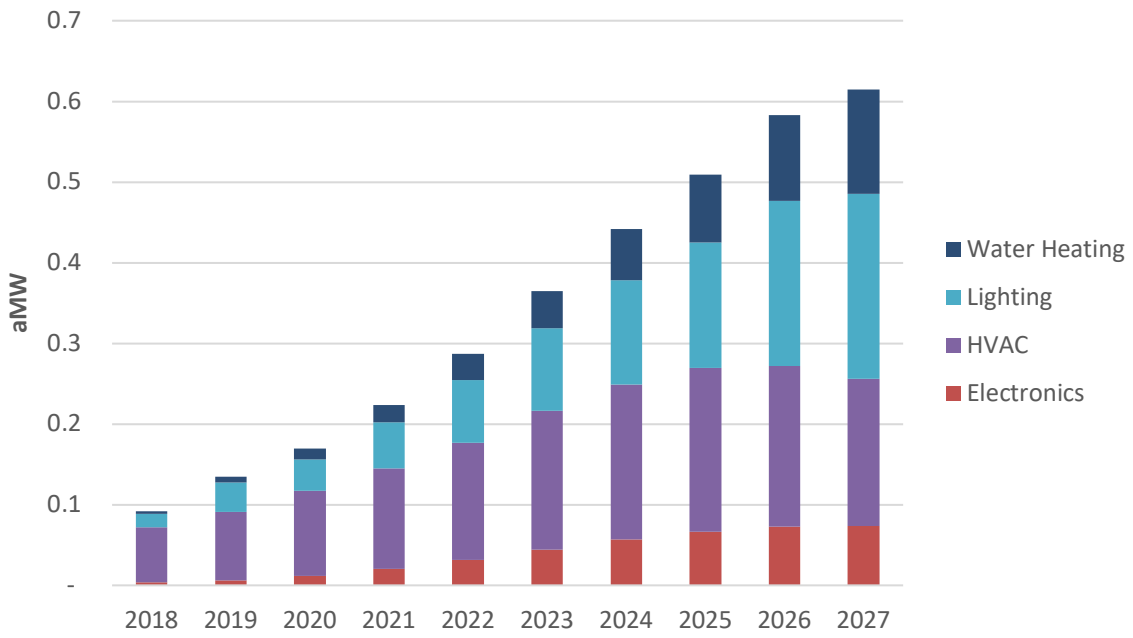
The largest share of the potential is in the industrial sector followed by savings potential in commercial and residential sectors. Achievement levels are affected by factors including timing and availability of measure installation (lost opportunity), program (technological) maturity, non-programmatic savings, and current utility staffing and funding. Figure 11 shows savings estimates are ramped up over the first 12 years of the study. The ramp rates selected reflect both resource availability and Grant PUD's current program levels and achievements.

Residential

Within the residential sector, HVAC measures, which includes both heating equipment and weatherization measures, account for a significant share of cost-effective conservation (Figure 12). In particular, notable savings are available through DHP supplements and HVAC conversions. Second to HVAC potential, residential lighting measures account for a considerable share of the sector potential. Residential lighting measures consist of a variety of LED products.

Savings are also available through residential water heating measures. Heat pump water heaters and low-flow showerheads are the two measures with the highest potential in the water heating end use.

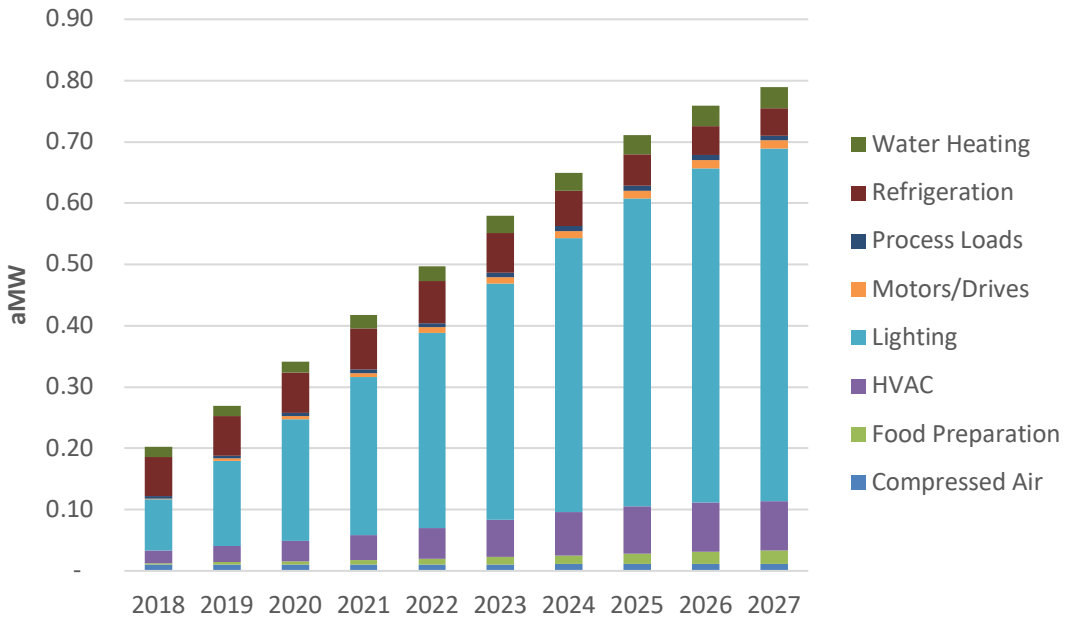
Figure 12
Annual Residential Potential by End Use



Commercial

Lighting measures make up the largest share of commercial conservation potential for the 2017 CPA planning period due to the continued improvement and widespread market adoption of LED products. Potential in HVAC measures is the category with the next highest amount of potential. Measures in this category include rooftop controllers, variable refrigerant flow HVAC systems, and commercial energy management practices. A variety of end uses make up the remaining commercial potential, reflecting the variety of systems used across the different building types (Figure 13).

Figure 13
Annual Commercial Potential by End Use



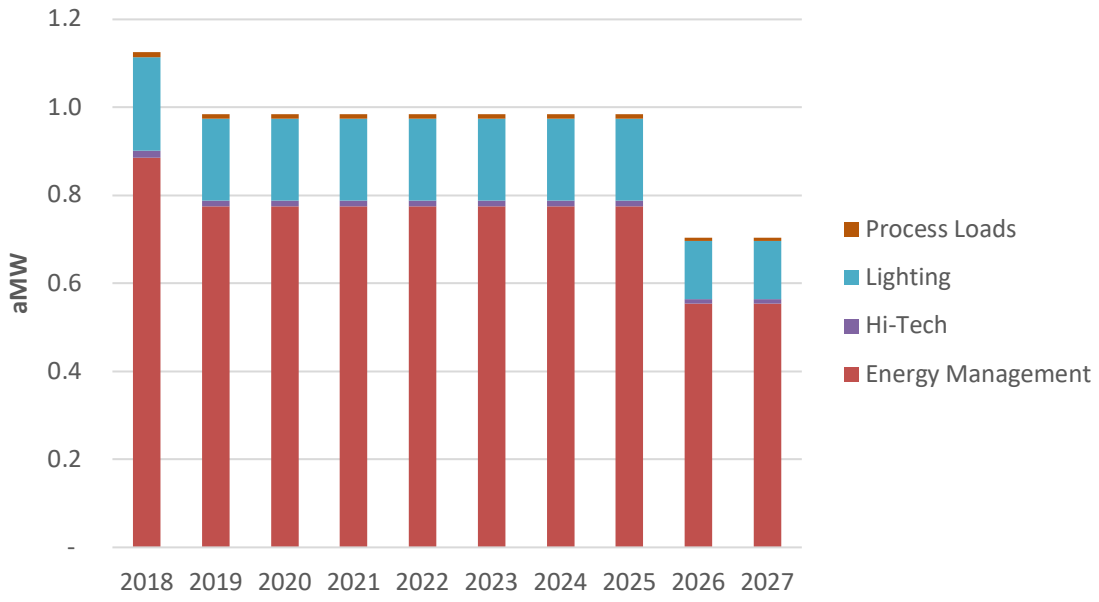
Industrial

As shown in Figure 14, Energy Management measures make up the largest category of savings in the industrial sector. This category includes Strategic Energy Management measures, such as those implemented in Grant PUD's Track & Tune program, as well as the efficient operation of motor-driven industrial systems.

Lighting measures make up the majority of the remaining industrial potential. As with the commercial sector, the improvement and proliferation of LED technology resulted in additional savings potential in this category.

Industrial potential was adjusted for Grant PUD's historic industrial sector achievement through the application of a custom ramp rate. This ramp rate aligns with Grant PUD's recent level of industrial sector achievement and holds steady over time with several incremental steps down. This allows for the utility and the industrial facilities to budget for larger industrial projects over time while still acquiring all cost-effective potential.

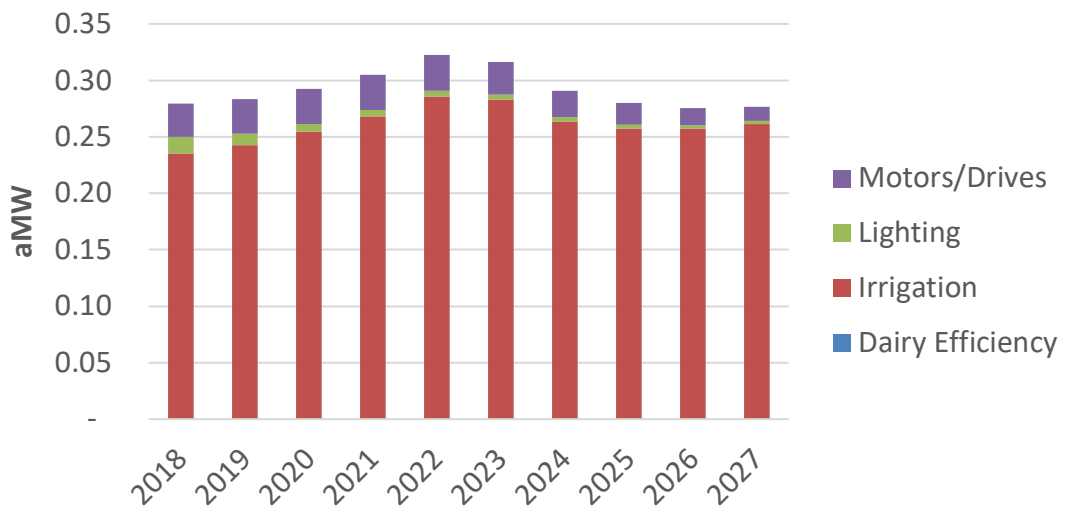
Figure 14
Annual Industrial Potential by End Use



Agriculture

Agriculture sector potential is a product of total acres under irrigation in Grant PUD's service territory, number of dairy cows, number of pumps, and the number of farms (used to estimate potential for area lighting measures). As shown in Figure 15, irrigation measures account for the largest area of conservation potential in the agriculture sector. The irrigation category includes irrigation hardware measures as well as low elevation spray application (LESA). The other categories of savings include motors, lighting, and dairy, but these savings categories are relatively small.

Figure 15
Annual Agriculture Potential by End Use



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 8). The assumptions in this estimate include: 20 percent of measure cost for administrative costs and 40 percent of the incremental cost for incentives is assumed to be paid by the utility. A 20 percent allocation of measure costs to administrative expenses is a standard assumption for conservation programs. This assumption was used in the Council's analysis for the Seventh Power Plan. Both the administrative cost allocation and the utility share assumptions are consistent with assumptions used in Grant PUD's 2015 CPA.

Table 8
Utility Program Costs (2017$)

	2-Year	6-Year	10-Year	20-Year
Residential	$689,000	$3,483,000	$8,101,000	$16,072,000
Commercial	$695,000	$3,502,000	$7,900,000	$18,852,000
Industrial	$2,513,000	$7,201,000	$11,219,000	$16,739,000
Agricultural	$349,000	$1,096,000	$1,822,000	$3,009,000
Distribution Efficiency	$0	$0	$0	$0
Total	**$4,246,000**	**$15,282,000**	**$29,042,000**	**$54,672,000**
$/First Year MWh	$132	$142	$149	$147

This table shows that Grant PUD can expect to spend approximately $4.2 million in order to acquire estimated savings over the next two years. This estimate includes estimated program administration costs.

The bottom row of Table 8 shows the cost per MWh of first-year savings. Utility conservation costs ($/MWh) are lower in the earlier years of the planning period and increase in later years as more cost-effective measures are acquired early in the study period. Annual conservation potential (and cost) is modeled using the Council's ramp rates for all sectors except the industrial sector, where a custom ramp rate was used. The Council applies ramp rates at the measure level to reflect the characteristics of a particular program (maturity, measure type, and availability etc.)

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement may be more costly since utilities often

choose to implement the lowest cost programs first. In addition, as energy efficiency markets become more saturated, it may require more effort from Grant PUD to acquire conservation through its programs. The additional effort may increase administrative or incentive costs.

Besides looking at the utility cost, Grant PUD may also wish to consider the total resource cost (TRC) cost of energy efficiency. The total resource cost reflects the cost the utility and ratepayers will together pay for conservation, similar to how the costs of other power resources are paid. The TRC costs are shown below (Table 9), levelized over the measure life of each measure. Most measures are in the neighborhood of two to four cents per kilowatt-hour.

Table 9
TRC Levelized Cost (2017$/kWh)

	2-Year	6-Year	10-Year	20-Year
Residential	$0.040	$0.039	$0.038	$0.034
Commercial	$0.036	$0.037	$0.037	$0.035
Industrial	$0.029	$0.029	$0.029	$0.029
Agricultural	$0.022	$0.021	$0.021	$0.021
Total	**$0.030**	**$0.031**	**$0.032**	**$0.032**

Scenario Results

The costs and savings discussed up to this point describe the Base Case scenario. Under this scenario, annual potential for the planning period was estimated by applying the Council's 20-year ramp rates to each measure. Ramp rates were chosen that best matched Grant PUD's recent levels of achievement. Additional scenarios were developed to identify a range of possible outcomes that account for uncertainties over the planning period. In addition to the Base Case scenario, this assessment tested Low and High scenarios to test the sensitivity of the results to different future avoided cost and growth assumptions. The avoided cost values in the Low and High scenarios reflect values that are realistic and lower or higher, respectively, than the Base Case assumptions.

To understand the sensitivity of the identified savings potential to avoided cost values alone, the growth rates were held constant while varying avoided cost inputs. The list below summarizes the growth rates for the Base Case:

- Residential growth = 1.5%
- Commercial growth = 1.2%
- Industrial growth = 1.4%

Table 10 summarizes the Base, Low, and High avoided cost input values. Rather than using a single generic risk adder applied to each unit of energy, the Low and High avoided cost values consider lower and higher potential future values for each avoided cost input. These values reflect potential price risks based upon both the energy and capacity value of each measure. The final row tabulates the implied risk adders for the Low and High scenarios by summarizing all additions or subtractions relative to the Base Case values. Risk adders are provided in both energy and demand savings values. The first set of values is the maximum (or minimum in the case of negative values). The second set of risk adder values are the average values in energy terms. Further discussion of these values is provided in Appendix IV.

Table 10 Avoided Cost Assumptions by Scenario, $2012			
	Base	**Low**	**High**
Energy, 20-yr levelized $/MWh	Market Forecast	-20%	+20%
Social Cost of Carbon, $/MWh	CA Carbon Market	$0	Federal/7th Power Plan Values
Value of REC Compliance	Current RPS	Current RPS	25% RPS
Distribution System Credit, $/kW-yr	$31	$31	$31
Transmission System Credit, $/kW-yr	$26	$26	$26
Deferred Generation Capacity Credit, $/kW-yr	3% Premium	$0	$115
Implied Risk Adder $/MWh $/kW-yr	N/A	Up to: -$23/MWh $0/kW-yr Average of: -$14/MWh $0/kW-yr	Up to: $19/MWh $115/kW-yr Average of: $16/MWh $115/kW-yr

Table 11 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

Table 11 Cost-Effective Potential - Avoided Cost Comparison (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Base Case	3.67	12.28	22.32	42.52
Low Avoided Costs	2.06	7.12	13.40	27.17
High Avoided Costs	5.55	18.94	35.31	70.94

Table 11 shows that the amount of cost-effective potential varies significantly with the changes in avoided cost. The changes are larger in scale in going from the Base Case to High avoided costs, suggesting a potential higher risk in undervaluing energy efficiency. Beyond the uncertainties in avoided costs, energy efficiency remains a low-risk investment since it is purchased in small increments over time, instead of singular large investments, such as investments in generation resources. Further reductions in the market energy prices, such as those predicted in the low scenario, are historically less likely.

Scenarios

Three additional scenarios were developed to identify a range of possible outcomes and to account for uncertainties over the planning period. In addition to the Base Case scenario, this analysis tested a Low scenario, and a High scenario, as well as an Accelerated Base Case scenario. The Low and High scenarios are relative to the Base Case.

These scenarios are discussed below and additional information regarding the development of conservation scenarios is provided in Appendix IV.

Low Scenario

The Low Conservation scenario evaluates energy efficiency cost effectiveness under a low growth scenario combined with the low avoided costs described above. Under the Low scenario, both residential and commercial growth are reduced to 0.5% percent. For the Low scenario, it is assumed that there is no industrial sector growth over the planning period.

Results of the Low scenario analysis are shown in Table 12. Under this scenario, 24.24 aMW of potential is cost-effective over the 20-year planning period.

Key parameters for the Low scenario include:

- Residential growth = 0.5%
- Commercial growth = 0.5%
- Industrial growth = 0.0%

Table 12
Cost-Effective Achievable Potential – Low Scenario (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.14	0.84	2.34	6.44
Commercial	0.34	1.52	3.28	7.76
Industrial	0.94	2.71	4.22	6.30
Agriculture	0.37	1.24	2.15	3.74
Total	**1.80**	**6.31**	**11.99**	**24.24**

High Scenario

Under the High scenario, residential growth is 1 percentage point higher compared with the Base Case scenario and commercial sector growth is 0.8 percentage points higher. Industrial sector growth is 3 percent overall. The High Scenario also includes the high avoided cost assumptions from Table 12. Results of the High scenario are shown in Table 13.

Under this scenario, 84.98 aMW of potential is cost-effective for the 20-year planning period.

Key parameters for the High scenario include:

- Residential growth = 2.5%
- Commercial growth = 2.0%
- Industrial growth = 3.0%

Table 13 Cost-Effective Achievable Potential – High Scenario (aMW)				
	2-Year	**5-Year**	**10-Year**	**20-Year**
Residential	0.50	3.02	8.29	25.04
Commercial	0.70	3.44	7.91	20.02
Industrial	5.27	15.10	23.53	35.12
Agriculture	0.60	1.90	3.06	4.79
TOTAL	**7.07**	**23.47**	**42.79**	**84.98**

Scenario Summary

The 2, 6, 10, and 20-year savings estimates for the four scenarios tested in this analysis are shown in Table 14, and Figure 16 graphs the Base, Low, and High scenarios.

Table 14 Cost-Effective Achievable Potential – Scenario Comparison (aMW)				
	2-Year	**5-Year**	**10-Year**	**20-Year**
Base Case	3.67	12.28	22.32	42.52
Low Scenario	1.80	6.31	11.99	24.24
High Case	7.07	23.47	42.79	84.98

Figure 16
Grant PUD Conservation Scenarios – Annual Potential (aMW)

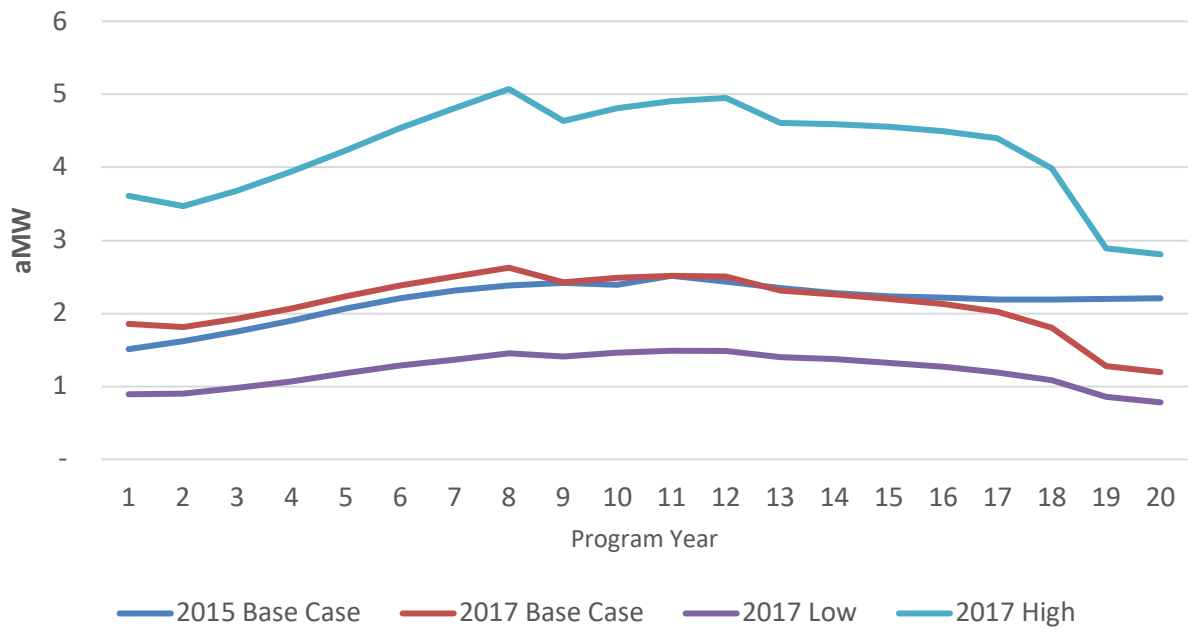


Figure 16 shows that the 2017 Base Case potential identified in this CPA is modestly higher than the early years of the 2015 Base Case from the 2015 CPA. Additional cost-effective potential identified throughout the report has led to additional savings opportunities through the early years of the study period. At the same time, the 2017 Base Case was set to be achievable through the selection of appropriate ramp rates that aligned well with Grant PUD's recent level of achievement.

Summary

This report summarizes the results of the 2017 CPA conducted for Grant County Public Utility District. The assessment provides estimates of energy savings by sector for the period 2018 to 2037, with a focus on the first 10 years of the planning period, as per EIA requirements. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

Methodology and Compliance with State Mandates

The energy efficiency potential reported in this document is calculated using methodology consistent with the Council's methodology for assessing conservation resources. Appendix III lists each requirement and describes how each item was completed. In addition to using methodology consistent with the Council's Seventh Power Plan, this assessment utilized many of the measure assumptions that the Council developed for the Seventh Power Plan. Utility-specific data regarding customer characteristics, service-area composition, and historic conservation achievements were used, in conjunction with the measures identified by the Council, to determine available energy-efficiency potential. Conservation potential was assessed for multiple periods: 2 years, 6 years, 10 years, and 20 years. These approaches are consistent with Council methodology, which enables compliance with the Washington State EIA.

Three types of energy-efficiency potential were calculated: technical, economic, and achievable. Most of the results shown in this report are the cost-effective potential, or the potential that is economically achievable in the Grant PUD service territory. The cost-effective potential considers savings that will be captured through utility program efforts, market transformation and implementation of codes and standards. Often, realization of full savings from a technology, particularly a new or emerging technology, will require efforts across all three areas. Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing as they become an important component of the efforts to meet aggressive regional conservation targets.

Conservation Targets

The EIA states utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent ten-year period."[5] However, the State Auditor's Office has stated that:

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[6]

The State Auditor's Office expects that qualifying utilities have analysis to support targets that are more or less than the 20 percent of the ten-year assessments. This document serves as support for the target selected by Grant PUD and approved by its Commission.

Summary

This study shows a range of conservation target scenarios. These scenarios are estimates based on the set of assumptions detailed in this report and supporting documentation and models. Due to the uncertainties discussed in the Introduction section of this report, actual available and cost-effective conservation may vary from the estimates provided in this report.

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[5] RCW 19.285.040 Energy conservation and renewable energy targets.

[6] State Auditor's Office. Energy Independence Act Criteria Analysis. Pro-Rata Definition. CA No. 2011-03. https://www.sao.wa.gov/local/Documents/CA_No_2011_03_pro-rata.pdf

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Appendix I – Acronyms

aMW –Average Megawatt

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light Bulb

CPU – Clark Public Utilities

EIA – Energy Independence Act

HLH – Heavy load hour energy

HVAC – Heating, ventilation and air-conditioning

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MF –Multi-Family

MH –Manufactured House

MW –Megawatt

MWh –Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

UC – Utility Cost

Appendix II – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A conservation measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

Lost Opportunity: Lost-opportunity measures are those that are only available at a specific time, such as new construction or equipment at the end of its life. Examples include heat-pump upgrades, appliances, or premium HVAC in commercial buildings.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined %ages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix III – Documenting Conservation Targets

References:

1) Report – "Grant PUD 2017 Conservation Potential Assessment". Draft Report –October 24, 2017.
2) Model – "EES CPA Model-v2.1b—RR Adjust" and supporting files
   a. MC_and_Loadshape_v3.0_24segment-Grant-Base-.xlsm – referred to as "MC and Loadshape file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
a) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could be physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
b) Achievable Potential: Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for Grant PUD used ramp rate curves to identify the amount of achievable potential for each measure. Those assumptions are for the 20-year planning period. An additional factor of 85% was included to account for market barriers in the calculation of achievable potential.	Model – the use of these factors can be found on the sector measure tabs, such as 'Residential Measures'. Additionally, the complete set of ramp rates used can be found on the 'Ramp Rates' tab.
c) **Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost ratio greater than one were tallied. These measures are considered achievable and cost-effective (or "economic").	Model – BC Ratios are calculated at the individual level by ProCost and passed up to the model.
d) **Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
e) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than one are cost-effective).	Model – the "Measure Info Rollup" files pull in all the results from each avoided cost scenario, including the BC ratios from the ProCost results. These results are then linked to by the Conservation Potential Assessment model. The TRC analysis is done at the lowest level of the model in the ProCost files.
f) Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's 7th Plan and RTF were used.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
g) Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's Seventh Plan measure load shapes were used to calculate time of day of savings and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost program so it was handled in the same way as the Seventh Power Plan models.	Model – See MC file for load shapes. The ProCost files handle the calculations.
h) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.
i) Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report –See Appendix IV. Model – See MC File ("TEA Base" worksheet).
j) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of $26/kW in the cost-effectiveness analysis. A local distribution system credit of $31/kW-yr was also used.	Model – this value can be found on the ProData page of each ProCost file.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
k) Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of $ 72/kW-yr in the cost effectiveness analysis. This is based upon Grant PUD's marginal cost for generation capacity.	Model – this value can be found on the ProData page of the ProCost Batch Runner file. The generation capacity value was not originally included as part of ProCost during the development of the 7th Plan, so the value has been combined with the transmission capacity benefit.
l) Include the social cost of carbon emissions from avoided non-conservation resources	The avoided cost data include estimates of future high, medium, and low CO_2 costs.	Multiple scenarios were analyzed and these scenarios include different levels of estimated costs and risk.
m) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources	In this analysis, risk was considered by varying avoided cost inputs and analyzing the variation in results. Rather than an individual and non-specific risk adder, our analysis included a range of possible values for each avoided cost input.	The scenarios section of the report documents the inputs used and the results associated.
n) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's Seventh Power Plan. Non-energy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for non-power benefits as the Council and RTF. The calculations are handled in by ProCost.
o) Include an estimate of program administrative costs	Total costs were tabulated and an estimated 20% of total was assigned as the administrative cost. This value is consistent with regional average and BPA programs. The 20% value was used in the Fifth, Sixth, and Seventh Power plans.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
p) Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure	Costs of financing measures were included utilizing the same assumptions from the Seventh Power Plan.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
q) Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating non-conservation resources	Discount rates were applied to each measure based upon the Council's methodology. A real discount rate of 4% was used, based on the Council's most recent analyses in support of the Seventh Plan	Model – this value can be found on the ProData page of the ProCost Batch Runner file.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
r) Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.

Appendix IV – Avoided Cost and Risk Exposure

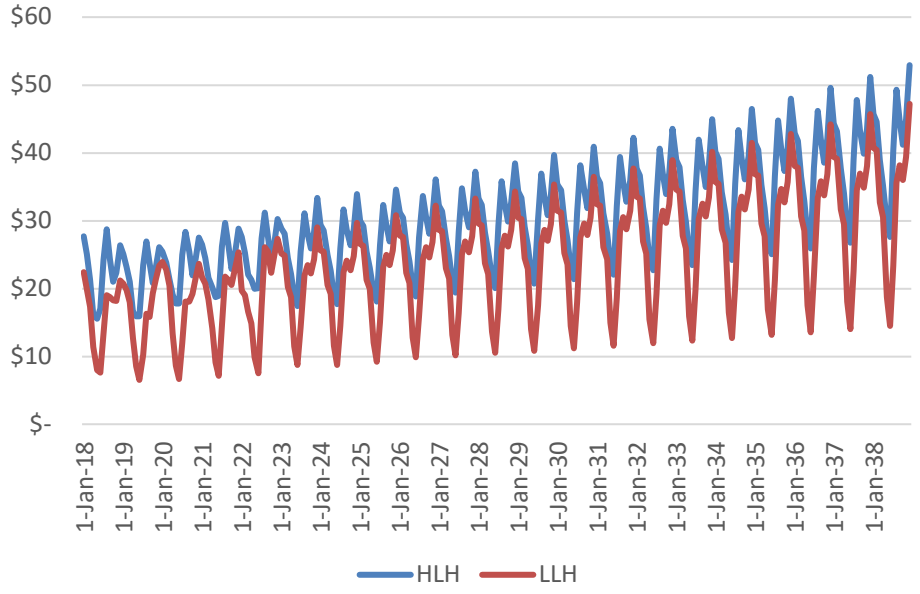
EES Consulting, Inc. (EES) has conducted a Conservation Potential Assessment (CPA) for Grant PUD (the District) for the period 2018 through 2037 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the District must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated including generation capacity value, local distribution and regional transmission costs, risk, and the social cost of carbon. This appendix describes each of the avoided cost assumptions and provides a range of values that was evaluated in the 2017 CPA. The 2017 CPA presents 4 scenarios: Base, Accelerated Base, Low, and High conservation scenarios. Each of these is discussed below.

Avoided Energy Value

For the purposes of the 2017 CPA, EES has used a forecast of market prices for the Mid-Columbia trading hub prepared by District staff. This section summarizes the market price forecast and compares the forecast to the market forecast used for the District's 2015 CPA (2016-17 biennium).

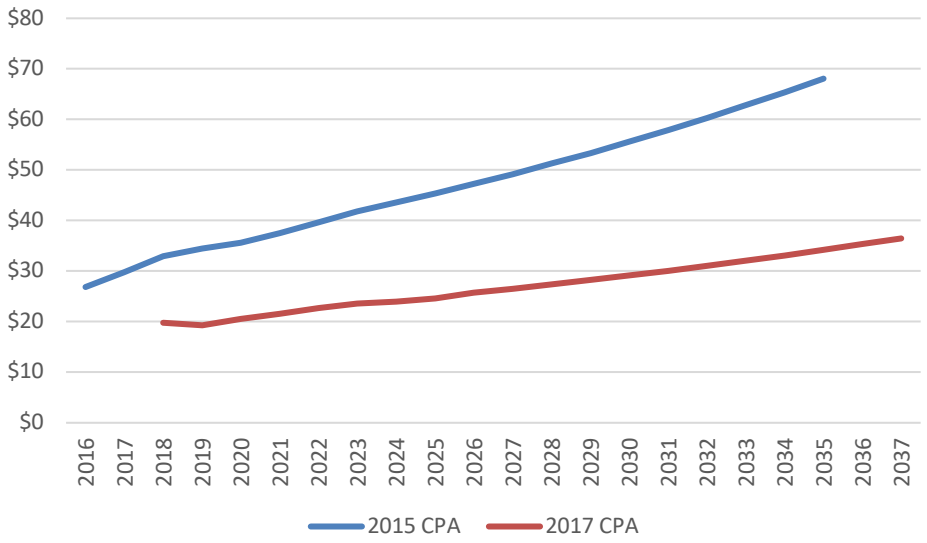
Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $26.10/MWh assuming a 4 percent real discount rate. The compound average annual growth rate over the 20-year study period is 3.3% percent.

Figure IV-1
Forecast Market Prices ($/MWh)



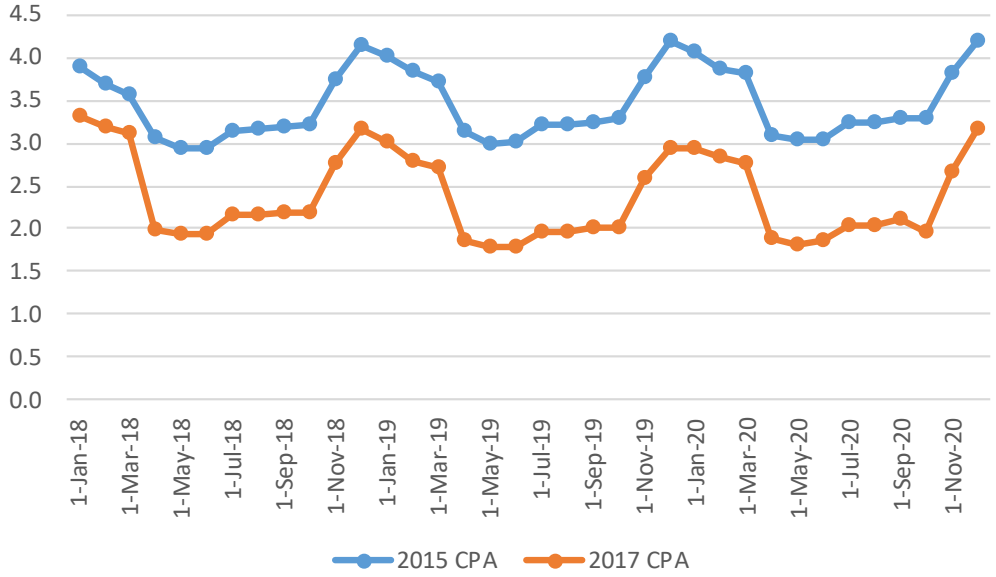
The 2017 market price forecast is lower than the market price forecast used in the District's most recent CPA (the 2015 CPA). Figure IV-2 compares the two forecasts.

Figure IV-2
Forecast Market Prices in 2015 CPA and 2017 CPA ($/MWh)



The 2017 CPA's market price forecast for the period 2018 through 2035 is 41 percent lower compared with the 2015 CPA's market price forecast due to changes in market conditions mainly due to decreases in natural gas prices. Figure IV-3 illustrates decrease in forward natural gas prices between the 2015 and 2017 CPAs. The projected average 2018 Sumas natural gas price included in the 2017 CPA ($2.51/MMBtu) is 26 percent less than the projected average 2018 Sumas natural gas price included in the 2015 CPA ($3.39/MMBtu).

Figure IV-3
Forward Sumas Natural Gas Prices ($/MMBtu)

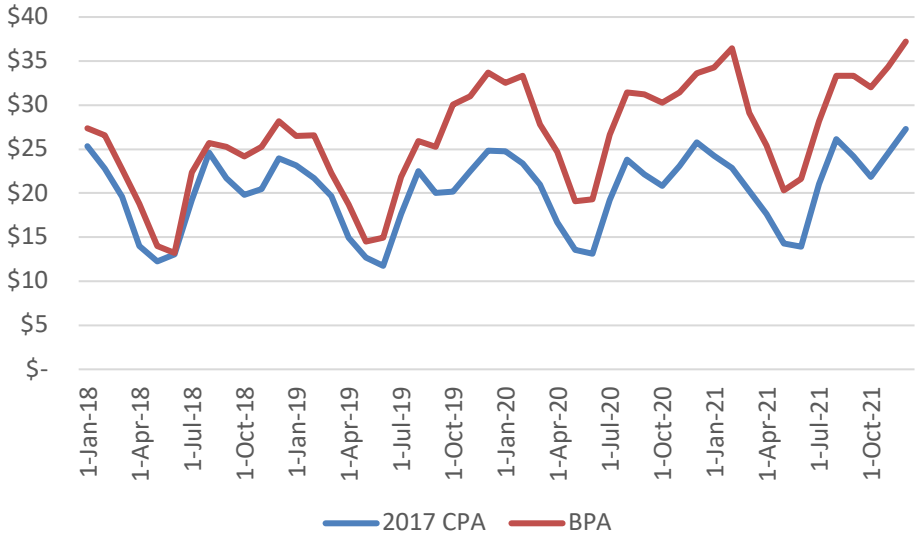


** Source: Henry Hub and Sumas Basis Differential Futures quotes as provided by CME Group*

Benchmarking

Figure IV-4 compares the January 2018 through December 2021 forecast with the forecast included in BPA's Final FY18-19 rates. The monthly shapes are similar, although BPA's forward prices are somewhat higher and show higher growth over time.

Figure IV-4
Forecast Market Prices compared to BPA's Market Price Forecast ($/MWh)



** BPA's market price forecast is per the market price forecast included in BPA's July 26 final proposal for FY18-19 power rates.*

High and Low Scenarios

To reflect a range of possible future outcomes, the analysis includes scenarios with high- and low-case market price forecasts. High and low price forecasts were created by adding or subtracting 20% from the base price forecast, respectively. This approach reflects possible error in the forecast while maintaining the annual shape and relationship between months.

Figures IV-5 and IV-6 compare the base, high, and low price forecasts, for high and low load hours,

respectively.

Figure IV-5
High Load Hour Market Price Forecast Comparison (2017$/MWh)

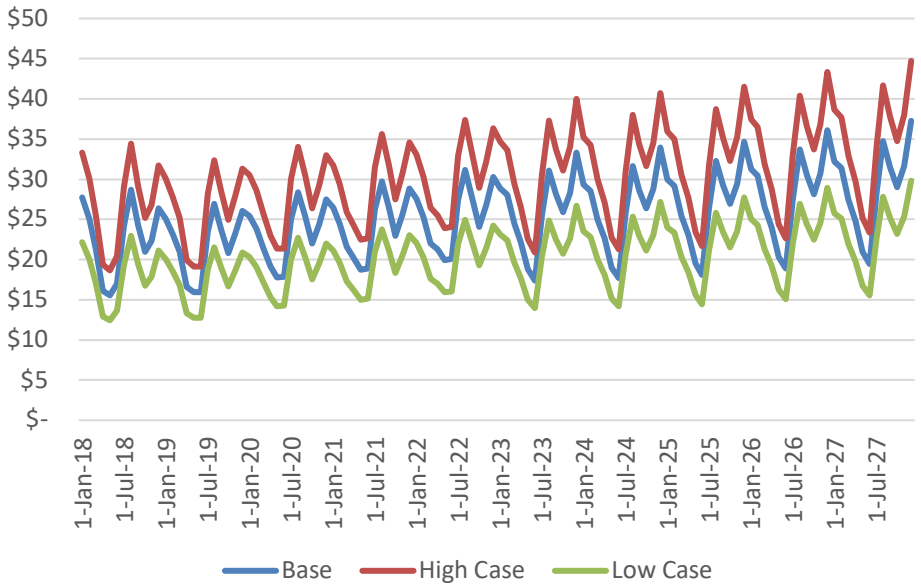
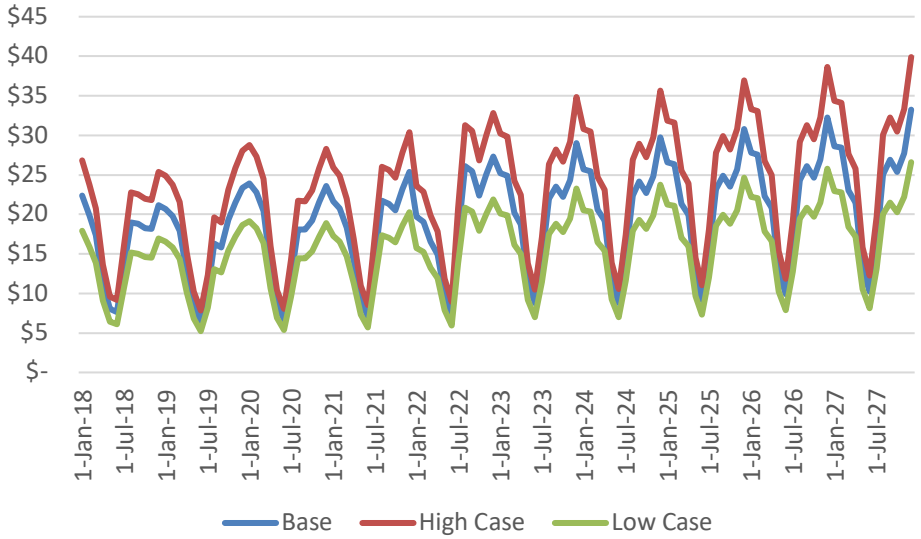


Figure IV-6
Low Load Hour Market Price Forecast Comparison (2017$/MWh)



Avoided Cost Adders and Risk

From a total resource cost perspective, energy efficiency provides multiple benefits beyond the avoided cost of energy. These include deferred capital expenses on generation, transmission, and distribution capacity; as well as the reduction of required renewable energy credit (REC) purchases, avoided social costs of carbon emissions, and the reduction of utility resource portfolio risk exposure. Since energy efficiency measures provide both peak demand (kW) and energy savings (kWh), these other benefits are monetized as value per unit of either kWh or kW savings.

Energy-Based Avoided Cost Adders:

1. Social Cost of Carbon
2. Renewable Energy Credits
3. Risk Reduction Premium

Peak Demand-Based Adders:

1. Generation Capacity Deferral
2. Transmission Capacity Deferral
3. Distribution Capacity Deferral

The estimated values and associated uncertainties for these avoided cost components are provided below. EES will evaluate the energy efficiency potential under a range of avoided cost adders, identifying the sensitivity of the results to changes in these values.

Social Cost of Carbon

The social cost of carbon is a value that society incurs when fossil fuels are burned to generate electricity. EIA rules require that the social cost of carbon be included in the total resource cost test (TRC). The value of the social cost of carbon is not defined by markets; therefore, the CPA includes the social cost of carbon in an uncertainty analysis through scenario modeling. The scenarios modeled include the value of the social cost of carbon from various resources. California's cap-and-trade carbon market prices were used in the base case, as these represent the closest analogue to a carbon market. Prices in the California market are currently near $14 per metric ton and are expected to rise to near $16 in 2020. The price floor in California's market is stipulated to rise at 5% plus inflation, so that escalation rate was used.

The Power Council used the federal Interagency Workgroup estimate of a social cost of carbon in

scenarios of the Seventh Power Plan. The federal carbon cost estimates range from $44 to $63 (2012$) per metric ton over the 20-year planning period. In addition, a value of zero is included in the low avoided cost scenario analysis. The zero value reflects that carbon costs are not likely to be borne by only utility ratepayers directly in the near future.

In addition to these carbon costs, the nature of the marginal generation source also needs to be considered. The District provided their average marginal carbon emissions rate of 0.428 metric tons per MWh, or 0.94 lbs per kWh.

Value of Renewable Energy Credits

Related to the social cost of carbon is the value of renewable energy credits. Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. Currently, utilities are required to source 9% of all electricity sold to retail customers from renewable energy resources. In 2020, the requirement increases to 15%.

The EIA allows for alternate modes of compliance. Utilities can comply by spending four percent or more of the annual retail revenue requirement on the incremental cost of renewable energy—essentially a four percent cost cap. Utilities with no load growth can comply by spending one percent or more of the retail revenue requirement.

For every 100-unti reduction in the District's load, the RPS compliance is reduced by 9 units (now) or 15 units (after 2019). In effect, this adds 9 or 15 percent of the costs of RECs to the avoided costs of energy efficiency.

In 2016, the District far exceeded its requirements to fulfill its requirement of sourcing 9% of its energy from renewable sources through the hydropower resources it owns as well as purchased Renewable Energy Credits (RECs). The District's 2016 IRP projects that it will have sufficient renewable generation to meet RPS requirements until 2023. Accordingly, the value of RECs was not counted until 2023. EES used an average of several forecasts to determine future REC prices.

To represent uncertainty in future RPS requirements, the existing policy will be modeled in the base and low cases. In the high case, an RPS requirement of 25 percent will be modeled to represent future potential increases in the stringency or cost of RPS compliance.

Risk Adder

In general, the risk that any utility faces is that energy efficiency will be undervalued, either in terms of the value per kWh or per kW of savings, leading to an under-investment in energy efficiency and exposure to higher market prices or preventable investments in infrastructure. The converse risk—an over-valuing of energy and subsequent over-investment in energy efficiency—is also possible, albeit less likely. For example, an over-investment would occur if an assumption is made that economies will remain basically the same as they are today and subsequent sector shifts or economic downturns cause large industrial customers to close their operations. Energy efficiency investments in these facilities may not have been in place long enough to provide the anticipated low-cost resource.

In order to address risk, the Council includes a risk adder ($/MWh) in its cost-effectiveness analysis of energy efficiency measures. This adder represents the value of energy efficiency savings not explicitly accounted for in the avoided cost parameters. The risk adder is included to ensure an efficient level of investment in energy efficiency resources under current planning conditions. Specifically, in cases where the market price has been low compared to historic levels, the risk adder accounts for the likely possibility that market prices will increase above current forecasts.

The value of the risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. In the Sixth Power Plan the risk adder was significant (up to $50/MWh for some measures). In the Seventh Power Plan the risk adder was determined to be $0/MWh after the addition of the generation capacity credit. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis.

For the District's 2017 CPA, the avoided cost parameters have been estimated explicitly, and, a scenario analysis is performed. Therefore, a risk adder of $0/MWh is used for the base case. Variation in other

avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of the District's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Local Distribution and Bulk Transmission System Investment

Energy efficiency measure savings reduce capacity requirements on both the local distribution system and the regional transmission system. The value of these capacity savings has been estimated in the Seventh Power Plan at $31/kW-year and $26/kW-year for distribution and transmission systems, respectively ($2012). These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

The District's 2016 IRP identifies that the current forward market provides a cost-effective option for meeting future demand and load growth, but cautions that the forward market may not always be available for capacity purchases, or available at the low prices present today. To represent the value of capacity in the base case, the District provided a value that represents a 3 percent premium over market prices. This value is based on the opportunity cost of selling excess energy and capacity in the market created by energy savings. In the low case, a value of $0/kW-yr was used. This represents a future in which the market will continue to be available for meeting peak demands. In the Council's Seventh Power Plan[7], a generation capacity value of $115/kW-year was explicitly calculated ($2012). This value will be used in the high scenario.

Summary of Scenario Assumptions

Table IV-1 summarizes the recommended scenario assumptions. The Base Case represents the most likely future.

Table IV-1
Avoided Cost Assumptions by Scenario, $2012

	Base	Low	High
Energy, 20-yr levelized $/MWh	Market Forecast	-20%	+20%
Social Cost of Carbon, $/MWh	CA Carbon Market	$0	Federal/7th Power Plan Values
Value of REC Compliance	Current RPS	Current RPS	25% RPS
Distribution System Credit, $/kW-yr	$31	$31	$31
Transmission System Credit, $/kW-yr	$26	$26	$26
Deferred Generation Capacity Credit, $/kW-yr	3% Premium	$0	$115
Implied Risk Adder $/MWh $/kW-yr	N/A	Up to: -$23/MWh $0/kW-yr Average of: -$14/MWh $0/kW-yr	Up to: $19/MWh $115/kW-yr Average of: $16/MWh $115/kW-yr

[7] https://www.nwcouncil.org/energy/powerplan/7/home/

Appendix V – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2017 CPA. The CPA evaluated thousands of measures; the measure list does not include each individual measure; rather it summarizes the measures at the category level, some of which are repeated across different units of stock, such as single family, multifamily, and manufactured homes. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure categories to more realistically reflect utility-conservation program organization and offerings. For example, single-family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

The measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed. The following tables list the conservation measures (at the category level) that were used to model conservation potential presented in this draft report. Measure data was sourced from the Council's Seventh Plan workbooks and the RTF's Unit Energy Savings (UES) workbooks. Please note that some measures may not be applicable to an individual utility's service territory based on characteristics of the utility's customer sectors.

Table V-1 Residential End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dryer	Heat Pump Clothes Dryer	7th Plan
Electronics	Advanced Power Strips	7th Plan, RTF
	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
Food Preparation	Electric Oven	7th Plan
	Microwave	7th Plan
HVAC	Air Source Heat Pump	7th Plan, RTF
	Controls, Commissioning, and Sizing	7th Plan, RTF
	Ductless Heat Pump	7th Plan, RTF
	Ducted Ductless Heat Pump	7th Plan
	Duct Sealing	7th Plan, RTF
	Ground Source Heat Pump	7th Plan, RTF
	Heat Recovery Ventilation	7th Plan
	Attic Insulation	7th Plan, RTF
	Floor Insulation	7th Plan, RTF
	Wall Insulation	7th Plan, RTF
	Windows	7th Plan, RTF
	Wi-Fi Enabled Thermostats	7th Plan
Lighting	Linear Fluorescent Lighting	7th Plan, RTF
	LED General Purpose and Dimmable	7th Plan, RTF
	LED Decorative and Mini-Base	7th Plan, RTF
	LED Globe	7th Plan, RTF
	LED Reflectors and Outdoor	7th Plan, RTF
	LED Three-Way	7th Plan, RTF
Refrigeration	Freezer	7th Plan
	Refrigerator	7th Plan
Water Heating	Aerator	7th Plan
	Behavior Savings	7th Plan
	Clothes Washer	7th Plan
	Dishwasher	7th Plan
	Heat Pump Water Heater	7th Plan, RTF
	Showerheads	7th Plan, RTF
	Solar Water Heater	7th Plan
	Wastewater Heat Recovery	7th Plan
Whole Building	EV Charging Equipment	7th Plan

Table V-2 Commercial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Controls, Equipment, & Demand Reduction	7th Plan
Electronics	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
	Smart Plug Power Strips	7th Plan, RTF
	Data Center Measures	7th Plan
Food Preparation	Combination Ovens	7th Plan, RTF
	Convection Ovens	7th Plan, RTF
	Fryers	7th Plan, RTF
	Hot Food Holding Cabinet	7th Plan, RTF
	Steamer	7th Plan, RTF
	Pre-Rinse Spray Valve	7th Plan, RTF
HVAC	Advanced Rooftop Controller	7th Plan
	Commercial Energy Management	7th Plan
	Demand Control Ventilation	7th Plan
	Ductless Heat Pumps	7th Plan
	Economizers	7th Plan
	Secondary Glazing Systems	7th Plan
	Variable Refrigerant Flow	7th Plan
	Web-Enabled Programmable Thermostat	7th Plan
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Exterior Building Lighting	7th Plan
	Exit Signs	7th Plan
	Lighting Controls	7th Plan
	Linear Fluorescent Lamps	7th Plan
	LED Lighting	7th Plan
	Street Lighting	7th Plan
Motors/Drives	ECM for Variable Air Volume	7th Plan
	Motor Rewinds	7th Plan
Process Loads	Municipal Water Supply	7th Plan
Refrigeration	Grocery Refrigeration Bundle	7th Plan, RTF
	Water Cooler Controls	7th Plan
Water Heating	Commercial Clothes Washer	7th Plan, RTF
	Showerheads	7th Plan
	Tank Water Heaters	7th Plan

Table V-3 Industrial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Air Compressor Equipment	7th Plan
	Demand Reduction	7th Plan
Energy Management	Air Compressor Optimization	7th Plan
	Energy Project Management	7th Plan
	Fan Energy Management	7th Plan
	Fan System Optimization	7th Plan
	Cold Storage Tune-up	7th Plan
	Chiller Optimization	7th Plan
	Integrated Plant Energy Management	7th Plan
	Plant Energy Management	7th Plan
	Pump Energy Management	7th Plan
	Pump System Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Equipment Upgrade	7th Plan
Hi-Tech	Clean Room Filter Strategy	7th Plan
	Clean Room HVAC	7th Plan
	Chip Fab: Eliminate Exhaust	7th Plan
	Chip Fab: Exhaust Injector	7th Plan
	Chip Fab: Reduce Gas Pressure	7th Plan
	Chip Fab: Solid State Chiller	7th Plan
Lighting	Efficient Lighting	7th Plan
	High-Bay Lighting	7th Plan
	Lighting Controls	7th Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	7th Plan
	Cold Storage Retrofit	7th Plan
	Grocery Distribution Retrofit	7th Plan
Material Handling	Material Handling Equipment	7th Plan
	Material Handling VFD	7th Plan
Metals	New Arc Furnace	7th Plan
Misc.	Synchronous Belts	7th Plan
	Food Storage: CO2 Scrubber	7th Plan
	Food Storage: Membrane	7th Plan
Motors	Motor Rewinds	7th Plan
Paper	Efficient Pulp Screen	7th Plan
	Material Handling	7th Plan
	Premium Control	7th Plan
	Premium Fan	7th Plan
Process Loads	Municipal Sewage Treatment	7th Plan
Pulp	Efficient Agitator	7th Plan
	Effluent Treatment System	7th Plan
	Premium Process	7th Plan
	Refiner Plate Improvement	7th Plan
	Refiner Replacement	7th Plan
Pumps	Equipment Upgrade	7th Plan
Transformers	New/Retrofit Transformer	7th Plan
Wood	Hydraulic Press	7th Plan
	Pneumatic Conveyor	7th Plan

Table V-4 Agricultural End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dairy Efficiency	Efficient Lighting	7th Plan
	Milk Pre-Cooler	7th Plan
	Vacuum Pump	7th Plan
Irrigation	Low Energy Sprinkler Application	7th Plan
	Irrigation Hardware	7th Plan, RTF
	Scientific Irrigation Scheduling	7th Plan, BPA
Lighting	Agricultural Lighting	7th Plan
Motors/Drives	Motor Rewinds	7th Plan

Appendix VI – Energy Efficiency Potential by End-Use

Table VI-1 Residential Economic Potential (aMW)				
	2 Year	**6 Year**	**10 Year**	**20 Year**
Dryer	-	-	-	-
Electronics	0.01	0.12	0.39	0.78
Food Preparation	0.00	0.01	0.02	0.06
HVAC	0.15	0.70	1.48	2.08
Lighting	0.05	0.33	1.05	3.73
Refrigeration	-	-	-	-
Water Heating	0.01	0.12	0.50	2.35
Whole Bldg/Meter Level	-	-	-	-
Total	**0.23**	**1.28**	**3.44**	**9.01**

Table VI-2 Commercial Economic Potential (aMW)				
	2 Year	**6 Year**	**10 Year**	**20 Year**
Compressed Air	0.02	0.06	0.11	0.22
Electronics	0.00	0.00	0.00	0.01
Food Preparation	0.01	0.04	0.11	0.37
HVAC	0.05	0.23	0.54	0.93
Lighting	0.22	1.38	3.45	9.35
Motors/Drives	0.01	0.04	0.09	0.24
Process Loads	0.01	0.03	0.07	0.08
Refrigeration	0.13	0.39	0.60	1.05
Water Heating	0.03	0.13	0.25	0.61
Total	**0.47**	**2.31**	**5.22**	**12.86**

Table VI-3 Industrial Economic Potential (aMW)				
	2 Year	**6 Year**	**10 Year**	**20 Year**
Compressed Air	0.09	0.26	0.41	0.61
Energy Management	1.66	4.76	7.42	11.08
Fans	0.00	0.00	0.00	0.01
Hi-Tech	0.03	0.08	0.13	0.19
Lighting	0.40	1.14	1.78	2.65
Low & Med Temp Refr	0.19	0.56	0.87	1.29
Material Handling	-	-	-	-
Metals	0.00	0.01	0.01	0.01
Misc	-	-	-	-
Motors	-	-	-	-
Paper	0.00	0.01	0.02	0.03
Process Loads	0.02	0.06	0.10	0.14
Pulp	-	-	-	-
Pumps	-	-	-	-
Transformers	-	-	-	-
Wood	-	-	-	-
Total	**2.40**	**6.89**	**10.74**	**16.02**

Table VI-4 Agricultural Economic Potential (aMW)				
	2 Year	**6 Year**	**10 Year**	**20 Year**
Dairy Efficiency	-	-	-	-
Irrigation	0.48	1.57	2.61	4.27
Lighting	0.02	0.05	0.06	0.07
Motors/Drives	0.06	0.18	0.25	0.29
Total	**0.56**	**1.80**	**2.92**	**4.63**

Appendix VII – Ramp Rate Documentation

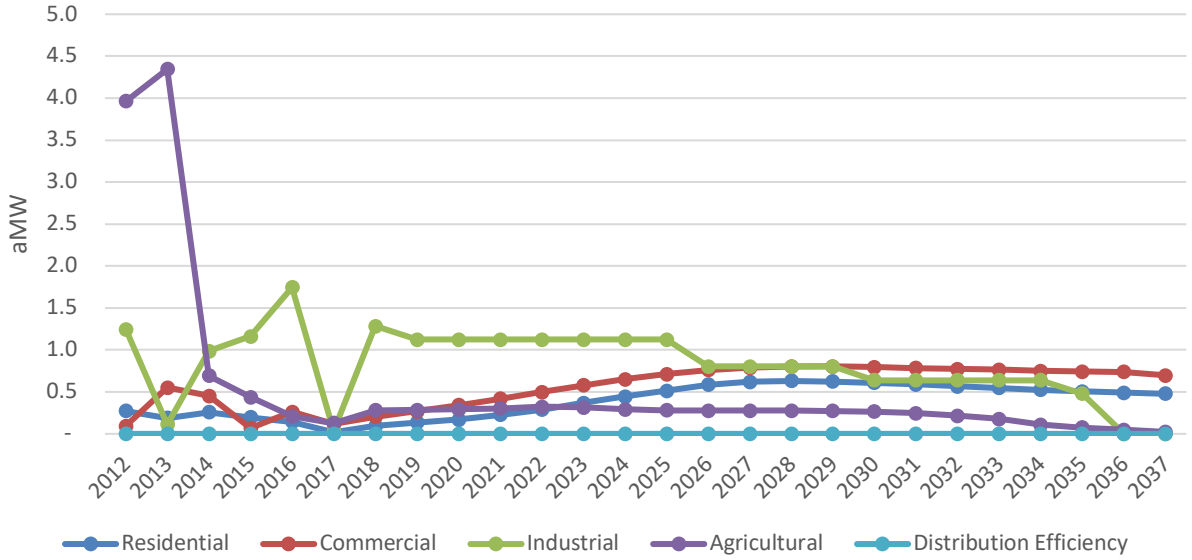
This appendix is included to document how ramp rates were adjusted to align near term potential with recent achievements of Grant PUD programs.

At first, Grant PUD's program achievements from 2012-2016 and estimates for 2017 were compared at a sector and end use level with the first years of the study period. Savings from NEEA's market transformation initiatives were allocated to the appropriate sectors. Sectors and end uses were identified where ramp rate adjustments were necessary. Alternate ramp rates were selected for major end uses in the residential and commercial sector to better align with Grant PUD's recent achievements.

For the industrial sector, a custom ramp rate was developed and applied to all measures. This ramp rate matches Grant PUD's recent level of industrial achievement and allows for an even level of savings acquisition over time, allowing both Grant PUD and industrial facilities to plan and budget for savings acquisition over time while still acquiring all cost-effective potential.

Figure VII-1 shows the resulting values.

Figure VII-1
Comparison of Recent Achievements with 2017 CPA Potential



Tables VII-1 and VII-2 compare recent achievements with near-term potential for the residential and commercial sectors, respectively.

Table VII-1 Comparison of Residential Achievements with 2017 CPA Potential							
End Use	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Water Heating	0.002	0.001	0.001	-	0.003	0.007	0.013
HVAC	0.166	0.184	0.092	0.004	0.069	0.085	0.106
Lighting	0.004	0.005	0.044	0.015	0.016	0.036	0.039
Electronics	-	-	-	-	0.004	0.006	0.012
Food Preparation	-	-	-	-	0.000	0.001	0.001
Dryer	-	-	-	-	-	-	-
Refrigeration	0.002	0.001	0.000	-	-	-	-
Whole Bldg/Meter Level	0.017	0.006	0.006	-	-	-	-
Total	**0.191**	**0.197**	**0.143**	**0.019**	**0.092**	**0.135**	**0.171**

Table VII-2 Comparison of residential Achievements with 2017 CPA Potential							
End Use	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Food Preparation					0.002	0.004	0.005
Lighting	0.135	0.039	0.167	0.101	0.083	0.140	0.198
Electronics					0.000	0.000	0.000
Refrigeration	0.113	0.030	0.095	-	0.064	0.064	0.066
Process Loads					0.003	0.004	0.005
Compressed Air					0.011	0.011	0.011
HVAC	0.181	-	-	0.016	0.021	0.026	0.033
Motors/Drives					0.002	0.004	0.005
Water Heating					0.017	0.017	0.018
Total	**0.429**	**0.069**	**0.261**	**0.118**	**0.203**	**0.270**	**0.342**

(Placeholder for official Memo to Manager)

APPENDIX 5: DEEP DECARBONIZATION AND HYDROPOWER

ARTICLES

Deep Decarbonization and Hydropower

by Charles R. Sensiba, Michael A. Swiger, and Sharon L. White

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Summary

Hydropower—both conventional and pumped storage hydropower—is crucial to sustaining our transition to a decarbonized grid. Additional hydropower development that meets modern environmental requirements is essential to reduce the United States' dependence on carbon. Realizing the full potential of hydropower and maintaining the current hydropower fleet will likely depend on overcoming a number of impediments, including lengthy and complex regulatory requirements, failure of electricity markets to adequately compensate hydropower generators for the grid benefits they provide, environmental opposition to new hydropower, and interest in dam removal. This Article, excerpted from Michael B. Gerrard & John C. Dernbach, eds., *Legal Pathways to Deep Decarbonization in the United States* (forthcoming in 2018 from ELI Press), examines how these challenges can be overcome with targeted legal and policy reforms.

I. Introduction

Hydropower, which generates electricity through falling water,[1] is the nation's most established and mature renewable resource, and accounts for more than 6% of all electricity generation and about one-half of all renewable power in the United States.[2] Hydropower resources serve an essential role supporting the electric grid by providing low-cost, flexible energy services, and a multitude of secondary benefits such as flood control, irrigation, water supply, and recreational opportunities. Hydropower also is critical in maintaining grid reliability and integrating variable generation resources, such as solar and wind, that continue to come online in larger numbers. Because solar and wind are intermittent resources, the electric grid cannot rely on them in all hours; no other renewables but hydropower, and to a lesser degree geothermal and biomass, are capable of quickly responding to the variable nature of wind and solar, coming on- and off-line when needed to ensure proper grid functioning.[3]

The Deep Decarbonization Pathways Project (DDPP) report, *Pathways to Deep Decarbonization in the United States*, recognizes the crucial role of hydropower to sustain our transition to a decarbonized electric grid—particularly with regard to hydropower pumped storage[4] and its ability to balance and integrate non-dispatchable renewables and water power.[5] In fact, the DDPP report assumes that the installed capacity of pumped storage will need to more than triple by 2050 to sustain a decarbonized grid.[6]

Authors' Note: The authors would like to acknowledge the extraordinary contributions of their colleagues, Julia Wood and Mealear Tauch of Van Ness Feldman LLP, toward the development of this work.

1. Hydropower also includes hydrokinetic technologies, which generate electricity from waves, currents, and tides within a water body.
2. *See* U.S. Energy Information Administration, *Hydropower Explained*, http://www.eia.gov/energyexplained/?page=hydropower_home (last updated June 13, 2017).
3. Combustion gas turbines also have this capability but are not renewable.
4. A pumped storage hydroelectric project can store and generate energy by pumping water between an upper and lower reservoir at different elevations. During times of low demand, water is pumped to the upper reservoir and stored, and during periods of high demand, the stored water is released through the turbines to generate electricity. Pumped storage is currently the only utility-scale energy storage technology available, although other storage technologies are emerging.
5. James H. Williams et al., Energy and Environmental Economics, Inc. et al., Pathways to Deep Decarbonization in the United States, US 2050 Report, Volume 1: Technical Report 17-20 (2015), *available at* http://usddpp.org/downloads/2014-technical-report.pdf.
6. To achieve this balancing, the authors of the DDPP report assumed the availability of 72 gigawatts (GW) of available pumped storage—50.4 GW more than the 21.6 GW installed in the United States as of 2016. E-mails From Jim Williams and Ryan Jones, Authors of the DDPP Report (Nov. 14-16, 2017) (on file with authors).

Still, the DDPP report did not fully account for the potential for environmentally responsible expansion of new conventional hydropower in the United States by 2050. Since that report was issued, the U.S. Department of Energy (DOE) released the results of a new investigation, *Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source*,[7] that sheds new light on the potential to expand both conventional and pumped storage hydropower. To chart a path for achieving the results envisioned in both the DDPP and DOE reports, this Article identifies new opportunities for sustainable growth, explains environmental risks and requirements pertaining to hydropower, and identifies legal and market reforms needed to capture a greater percentage of environmentally responsible hydropower—both conventional and pumped storage. We conclude that, based on its ability to provide electricity-generation capacity, baseload power, peaking power, energy storage, load following, and other essential generation features—together with its unique ability to integrate other renewables such as wind and solar into the grid—additional hydropower development above current levels that meets modern environmental requirements must be a component of any proposal to reduce the United States' dependence on carbon over the long term.

The DDPP report analyzes four distinct scenarios to achieve significant reductions in U.S. greenhouse gas (GHG) emissions by 2050, organized by the primary energy choices for electricity: (1) renewable energy (High Renewables Scenario); (2) nuclear (High Nuclear Scenario); (3) fossil fuels with carbon capture and storage (CCS) (High CCS Scenario); and (4) the Mixed Scenario with roughly equivalent generation from all three primary energy resources. In all but the High CCS Scenario, the percentage share of hydropower in overall electricity generation decreases from current levels. In the Mixed Scenario, which is the main case for the report, the percentage share of hydro in overall electricity generation decreases from 6.2% in 2014 to 5.6% in 2050 due to overall growth in electricity consumption but without substantial new growth in hydropower resources.[8] The report asserts that hydropower is not expected to keep pace with electricity growth because "development of new hydropower resources is . . . limited for sustainability reasons" as well as resource constraints.[9]

It is correct that hydropower is more site-limited than other resources; it requires a site where the natural flow and falling of water can be captured. However, the DDPP report does not explain its conclusion that hydropower is limited due to "sustainability." The report itself assumes that the amount of pumped storage must triple to effectively balance non-dispatchable renewables and nuclear power.[10] Moreover, the report makes no mention of development opportunities for conventional hydropower by adding hydropower infrastructure at existing dams, making capacity and efficiency upgrades at existing hydropower projects, implementing new technologies at low-head dams that were once infeasible, and deploying emerging marine and hydrokinetic (MHK) technologies to achieve emissions reduction goals—all of which, if developed in accordance with modern environmental requirements, can enhance balancing of the grid, add dispatchable resources, and meet "sustainability" considerations.

In its *Hydropower Vision* report, which was released after the DDPP report, DOE estimates that hydropower in the United States could feasibly grow from 101 gigawatts (GW) of emissions-free[11] generating and storage capacity to nearly 150 GW by 2050, avoiding 5.6 billion metric tons of carbon dioxide (CO_2) emissions, saving $209 billion in avoided global damages from CO_2 emissions, and creating more than 195,000 new jobs.[12] While much of this potential—consistent with the assumptions in the DDPP report—comes from a significant increase in pumped storage,[13] the DOE report finds opportunity for 13 GW of new conventional hydropower generation capacity at new and existing facilities.[14] The *Hydropower Vision* report did not include MHK technologies, which represent potential additional sources of hydropower development in future years.

Beyond the modeled increases of hydropower in the DDPP report, the DOE report demonstrates the considerable role that hydropower—both conventional and pumped storage—could play in nationwide decarbonization, and indicates that there are more available opportunities and pathways for the expansion of hydropower than the DDPP report assumes to meet the nation's climate goals. The legal pathways described in this Article for hydropower provide additional approaches to achieving the 80% reduction in GHG emissions by 2050 envisioned in the DDPP report, provide additional options to public and private decisionmakers (including options that are less expensive or have greater economic, social, and environmental benefits), and increase the likelihood that the required reduction can be achieved.

Realizing this full potential and even maintaining the current hydropower fleet will likely depend on overcoming a number of impediments to hydropower in the United States. Because expanding hydropower at federally constructed and operated dams is generally constrained by

7. DOE, Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source (2016) (DOE/GO-102016-4689) [hereinafter Hydropower Vision], *available at* http://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.
8. Williams et al., *supra* note 5, tbl. 7.
9. *Id.* at 12.
10. *See supra* note 6.
11. While some research asserts that reservoirs created by dams are important sources of GHG emissions, DOE's *Hydropower Vision* report notes that "[g]iven the state of scientific understanding and discourse, including persistent uncertainties, the [report] does not attempt to address hydropower-related biogenic GHG emissions." Hydropower Vision, *supra* note 7, at 43. Moreover, the research analyzed reservoirs impounded by both hydroelectric and non-hydroelectric dams, and only 3% of U.S. dams currently have a hydroelectric component. Thus, adding hydropower at these existing dams would not result in an increase in GHG emissions.
12. *Id.* at 3, 23.
13. *See supra* note 6.
14. Hydropower Vision, *supra* note 7, at xvii, 1, 7, 31.

competing agency priorities and depends on congressional authorization and funding,[15] for purposes of this Article, we focus on the impediments to nonfederal hydropower development. Such impediments include lengthy and complex regulatory requirements, failure of the organized electricity markets to adequately compensate hydropower generators for the grid benefits they provide, environmental opposition to new hydropower, and interest in dam removal. These challenges can be overcome with targeted legal and policy reforms that would not roll back environmental standards.

For the past 30 years, conventional wisdom in the United States has generally maintained that environmental impacts of new hydropower outweigh the benefits.[16] However, the expansions of hydropower under consideration today in the United States for the most part do not include new large dam construction or greenfield development. Also, new technologies have allowed hydropower owners and developers to effectively mitigate environmental effects of existing projects, increase generation at existing projects, and pursue hydropower at low-impact sites such as existing, non-powered dams. While all energy projects, including hydropower, come with environmental effects, the impacts of most new hydropower development today are significantly less than those of the large, new dam projects built in the previous century,[17] and the large dam projects in the United States are improving environmental performance more than ever before.[18]

The Article provides an overview of the potential to expand hydropower in the United States and the regulatory and market impediments that challenge this expansion. Part II begins with a brief discussion of the regulatory framework associated with nonfederal hydropower projects in the United States and environmental requirements that are specific to, or of particular significance in, the licensing of hydropower projects. Next, Part III identifies the regulatory impediments to the expansion of nonfederal hydropower and discusses solutions to overcome these impediments. Finally, Part IV discusses the market impediments to the expansion of hydropower and makes recommendations to incentivize the expansion of hydropower resources in the United States, and Part V concludes.

II. Overview of Hydropower Regulation and Hydropower Development Potential

As of the end of 2015, there were 2,198 active conventional hydropower plants in the United States owned and operated by federal and nonfederal entities, with a cumulative capacity of 79.6 GW, together with 42 pumped storage plants with a cumulative capacity of 21.6 GW, resulting in a total of 101 GW of installed hydropower capacity.[19] These plants (excluding pumped storage), over the 10-year period from 2006-2015, produced an average of 270,000 GW hours of electricity each year,[20] which powers 85 million homes and avoids nearly 190 million metric tons of CO_2 emissions annually.[21] Hydropower in the United States consists of conventional hydropower plants, including traditional large dams and small hydropower plants (including conduit and low-head projects),[22] open- and

15. Hydropower generation at large federal dams has been curtailed in recent years by environmental requirements. For example, the federal agencies operating dams on the Columbia River must comply with a biological opinion (BiOp) under the Endangered Species Act (ESA) issued in 2008 and updated in 2014 for 13 species of Columbia River Basin salmon and steelhead. The BiOp requires a series of mitigation measures, including spilling water over the dams in the spring and summer to help juvenile salmon and steelhead migrate safely to the ocean. *See* National Oceanic and Atmospheric Administration Fisheries, *Federal Columbia River Power System Biological Opinion*, http://www.westcoast.fisheries.noaa.gov/fish_passage/fcrps_opinion/federal_columbia_river_power_system.html (last visited Dec. 11, 2017). In addition, under the Glen Canyon Dam Long-Term Experimental and Management Plan Environmental Impact Statement, issued in October 2016, the Bureau of Reclamation and the National Park Service, which operate the Glen Canyon Dam, would be obligated to provide flow and non-flow measures for the benefit of fishery resources. U.S. Department of the Interior (DOI) et al., Glen Canyon Dam Long-Term Experimental and Management Plan Final Environmental Impact Statement 2-41 to 2-72 (2016), http://ltempeis.anl.gov/documents/final-eis/. These environmental restrictions have resulted in substantial losses in electrical generation. *Id.* at 4-335, tbl. 4.13-1 (Alternative D (the preferred alternative) results in a 1.1% decrease in average daily generation and a 6.7% decrease in firm capacity).

16. *See*, *e.g.*, Dan Tarlock, *Hydro Law and the Future of Hydroelectric Power Generation in the United States*, 65 Vand. L. Rev. 1723 (2012); Dan Tarlock, *The Legal-Political Barriers to Ramping Up Hydro*, 86 Chi.-Kent L. Rev. 259 (2011). *But see* Lea Kosnik, *The Potential of Water Power in the Fight Against Global Warming in the US*, 36 Energy Pol'y 3252 (2008); Lea Kosnik, *The Potential for Small Scale Hydropower Development in the US*, 38 Energy Pol'y 5512, 5518 (2010).

17. For example, with the installation of hydropower capability at existing non-powered dams, "many of the costs and environmental impacts of dam construction have already been incurred . . . and may not be significantly increased by the incorporation of new energy production facilities." Office of Energy Efficiency and Renewable Energy, DOE, An Assessment of Energy Potential at Non-Powered Dams in the United States 5 (2012) (GPO DOE/EE-0711) [hereinafter Assessment of Energy Potential at Non-Powered Dams], *available at* http://www1.eere.energy.gov/water/pdfs/npd_report.pdf.

18. The emergence of modern environmental requirements over the past 50 years, as discussed in Part III.B. below, including enactment of the Electric Consumers Protection Act of 1986 and the Energy Policy Act of 2005 (EPAct 2005), has improved the environmental performance of new and existing Federal Energy Regulatory Commission (FERC)-licensed hydropower facilities.

19. Hydropower Vision, *supra* note 7, at 2; *see also* Office of Energy Efficiency and Renewable Energy, DOE, 2014 Hydropower Market Report 5, 47 (2015) (DOE/EE-1195) [hereinafter 2014 Hydropower Market Report], *available at* https://energy.gov/sites/prod/files/2015/05/f22/2014%20Hydropower%20Market%20Report_20150512_rev6.pdf.

20. U.S. Energy Information Administration, Electricity Data Browser Report No. 1.1, Net Generation by Energy Source: Total—All Sectors.

21. *See* 2014 Hydropower Market Report, *supra* note 19, at 36 (reporting that the capacity factor for the U.S. hydropower fleet was 39% in 2013); U.S. Energy Information Administration, *Frequently Asked Questions* (noting average annual electricity consumption for a U.S. residential utility customer is 10,766 kilowatt hours), https://www.eia.gov/tools/faqs/faq.php?id=97&t=3 (last updated Nov. 7, 2017); U.S. Environmental Protection Agency (EPA), *Greenhouse Gas Equivalencies Calculator*, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator (last updated Sept. 2017).

22. Conventional hydropower plants can be operated for water storage (or impoundment) or as run-of-river or diversion (without the need for a reservoir). Kelsi Bracmort et al., Congressional Research Service, Hydropower: Federal and Nonfederal Investment 2 (2015), *available at* https://fas.org/sgp/crs/misc/R42579.pdf.

closed-circuit pumped storage, and MHK and new technology projects.

Of the existing hydropower fleet, federal agencies, including the U.S. Army Corps of Engineers (the Corps), the Bureau of Reclamation, and the Tennessee Valley Authority, own approximately 49% of installed capacity. Public entities, including public utility districts, irrigation districts, states, and rural cooperatives, own 24% of installed capacity, and private entities, including investor-owned utilities, independent power producers, and industrial companies, own the remaining 27% of installed capacity.[23] This Article focuses entirely on nonfederal hydropower, which has the highest growth potential, and is highly regulated and must be reauthorized every 30 to 50 years.

Nonfederal hydropower projects are licensed pursuant to the Federal Power Act (FPA),[24] which involves a lengthy process that can result in significant new environmental obligations and operational restraints. These projects also are subject to the substantive and procedural requirements of a number of federal environmental statutes that complicate and extend the licensing process. While there is ample opportunity to expand hydropower development in the United States, such expansion will depend on regulatory reform and emerging new hydropower technologies (such as low-head conventional and MHK technologies) to develop projects at lower costs and with improved environmental performance. In addition to expanding hydropower, reforms must be undertaken to preserve the existing fleet to continue hydropower's contributions to U.S. renewable generation.

A. *Regulation Over Nonfederal Hydropower Under the FPA*

Nonfederal hydropower projects are one of the most heavily regulated energy resources in the nation. The current regulatory system, which is expensive, time-consuming, overlapping with other federal requirements, and often results in the loss of operational flexibility and reduction in capacity factor,[25] makes it difficult for hydropower to fairly compete with emitting resources (primarily natural gas).[26] Modernization and reform of the legislative and administrative policies currently governing the licensing and administration of hydropower, without compromising environmental standards, will be necessary for hydropower to effectively participate in the decarbonization of the U.S. electric grid.

The vast majority of hydropower dams owned and operated by nonfederal entities in the United States are regulated by the Federal Energy Regulatory Commission (FERC).[27] FERC holds exclusive authority under the FPA to issue licenses authorizing the construction, operation, and maintenance of new and existing hydropower projects.[28] In carrying out its statutory responsibilities, FERC is required to consider all the factors affecting the public interest in the comprehensive development of a waterway, including power development, navigation, water supply, recreation, and appropriate conditions to protect the environment.[29] FERC is obligated under the FPA to include conditions in an operating license to: (1) ensure a comprehensive development of the waterway that balances various uses such as hydropower power development, public recreation, and environmental protection[30]; (2) protect fish and wildlife resources as recommended by certain resource agencies[31]; (3) adequately protect and utilize federal reservations occupied by the project, as directed by the federal agency that manages the reservation[32]; and (4) establish annual charges to be paid by the licensee.[33] All FERC hydropower licenses also include standard conditions related to land management and ownership requirements, dam safety, and authorization for FERC to reopen the license and reestablish a licensee's obligations under certain circumstances.[34]

The FPA also provides mandatory conditioning authority for federal agencies at certain projects. For projects located on federal reservations, the FPA requires that any license issued by FERC must incorporate any conditions

23. Hydropower Vision, *supra* note 7, at 11, 78.
24. 41 Stat. 1063, as amended, 16 U.S.C. §§791a et seq.
25. Capacity factor of a power plant is the measure of its actual output compared to its potential maximum output.
26. *See* Hydropower Vision, *supra* note 7, at 143 (explaining that the lengthy time line to license and permit new hydropower development "can lead developers and utilities to favor other generation technologies with shorter times to achieve commercial operation, such as natural gas turbines"). *See also Hearing on Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination Under the Natural Gas Act Before the House Comm. on Energy and Commerce, Subcomm. on Power and Energy*, 114th Cong. 9 (2017) (testimony of John Suloway, National Hydropower Association) (explaining that "the regulatory approval processes for simple cycle turbine or combined cycle plants are generally 1-2 years—even in urban areas like New York City"), http://docs.house.gov/meetings/IF/IF03/20150513/103443/HHRG-114-IF03-Wstate-SulowayJ-20150513.pdf.
27. Projects under FERC's jurisdiction include those that: (1) are located "across, along, or in any of the navigable waters of the United States"; (2) occupy "any part of the public lands or reservations of the United States"; (3) "utilize the surplus water or water power from any Government dam"; (4) are located on non-navigable waterways that are subject to Congress's Commerce Clause jurisdiction; (5) affect interstate or foreign commerce; and (6) have undergone construction or major modification after August 26, 1935. 16 U.S.C. §817(1). The Hydropower Regulatory Efficiency Act (HREA) of 2013, Pub. L. No. 113-23, 127 Stat. 493, excluded from FERC's mandatory licensing jurisdiction qualifying conduit hydropower facilities less than 5 MW that use only the hydroelectric potential of a nonfederally owned conduit. The Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act, Pub. L. No. 113-24, 127 Stat. 498 (2013), shifted jurisdiction over conduit projects less than 5 MW at Bureau of Reclamation facilities from FERC to the Bureau of Reclamation.
28. 16 U.S.C. §797(e).
29. *Id.* §§797(e), 803(a)(1).
30. *Id.* §803(a)(1).
31. *Id.* §803(j).
32. *Id.* §797(e). "Reservations" are defined under the FPA as
> national forests, tribal lands embraced within Indian reservations, military reservations, and other lands and interests in lands owned by the United States, and withdrawn, reserved, or withheld from private appropriation and disposal under the public land laws; also lands and interests in lands acquired and held for any public purposes; but shall not include national monuments or national parks.

Id. §796(2). *See also* Federal Power Comm'n v. Tuscarora Indian Nation, 362 U.S. 99, 111 (1960).
33. 16 U.S.C. §803(e), (f).
34. 18 C.F.R. §2.9 (2017) (identifying FERC's standard-form license conditions).

imposed by the secretary of the department that supervises the reservation.[35] The FPA also directs FERC to require the licensee to construct any fishways for the safe and timely upstream and downstream passage of fish that may be prescribed by the federal fishery agencies.[36] FERC is not authorized to modify and is required to include the agencies' conditions and prescriptions in a license.[37] Licensees and other parties to a licensing have a limited ability to challenge disputed issues of material fact with respect to mandatory conditions and prescriptions through a trial-type hearing before an administrative law judge, or to propose alternative conditions and prescriptions to the federal agency during the licensing.[38]

B. *Environmental Regulation Over Nonfederal Hydropower Under Federal Environmental Statutes*

In addition to the requirements of the FPA, modern environmental statutes, including the National Environmental Policy Act (NEPA), Clean Water Act (CWA), Endangered Species Act (ESA), National Historic Preservation Act (NHPA), and Coastal Zone Management Act (CZMA), each require additional substantive and procedural requirements that complicate and extend the licensing process.[39]

NEPA requires all agencies to prepare an environmental impact statement (EIS) for federal actions significantly affecting the quality of the human environment.[40] FERC's regulations require it to prepare an EIS for an original license to construct a new hydroelectric facility, but allow the agency—if it determines that the facility will not significantly affect the quality of the human environment—to instead prepare an environmental assessment (which is less detailed).[41] The environmental document prepared under NEPA must examine a project's effects on the environment and alternatives to the project.[42] NEPA also applies to other agency decisions in hydropower development, including Corps permits under the CWA and federal land management agency permits under the Federal Land Policy and Management Act (FLPMA).[43]

The CWA reserves significant authority to the states to participate in the licensing process and condition FERC-issued licenses.[44] Under this statute, "[a]ny applicant for a Federal license or permit to conduct any activity . . . which may result in any discharge into the navigable waters" is required to "provide the licensing or permitting agency a certification from the State in which the discharge originates . . . that any such discharge will comply" with state water quality standards.[45] As discharges from a dam, such as flows over the project's spillway and through the powerhouse, trigger certification under the CWA,[46] the state may impose conditions to its water quality certification that it deems necessary to ensure compliance with state water quality standards, which become conditions of the license that FERC may not reject.[47] The U.S. Supreme Court has endorsed a broad interpretation of state conditioning authority under §401, holding that a state may impose instream flow requirements and conditions to protect recreational and aesthetic values, as part of its water quality certification.[48]

The ESA requires FERC, in consultation with the federal fish and wildlife agencies, to ensure that the projects it authorizes do not jeopardize endangered or threatened species or their critical habitat.[49] If FERC determines that an endangered or threatened species is likely to be affected by a project, it must enter into formal consultation with the federal agencies, and the agency must prepare a biological opinion (BiOp). If the agency determines that the project may jeopardize the species or adversely affect its critical habitat, the BiOp can include "reasonable and prudent alternatives" to the project, which FERC typically adopts as part of its license. BiOps are a frequent source of delay in the FERC relicensing process, sometimes delaying license issuance by several years or more.[50]

The CZMA and NHPA impose additional requirements on FERC before it may issue a license for a hydropower project. The CZMA requires hydroelectric facilities within a state's coastal zone to conform to the state's coastal zone management plan.[51] FERC may issue a license only if the state agency concurs that the project is consistent with the state's coastal zone management plan. The NHPA requires

35. 16 U.S.C. §797(e).
36. *Id.* §811. The U.S. Fish and Wildlife Service (FWS) is responsible for freshwater and terrestrial species, while the National Marine Fisheries Service (NMFS) is responsible for marine and anadromous species.
37. *See* American Rivers v. Federal Energy Regulatory Comm'n, 187 F.3d 1007, 1030 (9th Cir. 1999) (holding that FERC "may not modify, reject, or reclassify any prescriptions submitted by the Secretaries under color of section 18").
38. EPAct 2005, Pub. L. No. 109-58, 119 Stat. 594. For a more in-depth discussion of FERC's jurisdiction over nonfederal hydropower projects, see Michael A. Swiger et al., *Hydroelectric Regulation Under the Federal Power Act*, *in* Waters and Water Rights (Amy Kelley ed., Matthew Bender 2009), and Michael A. Swiger et al., *Hydroelectric Power*, *in* Energy Law and Transactions (William A. Mogel & David J. Muchow eds., Matthew Bender 2009).
39. NEPA, 42 U.S.C. §§4321-4370h; CWA, 33 U.S.C. §§1251-1387; ESA, 16 U.S.C. §§1531-1544; NHPA, 16 U.S.C. §§470-470x; CZMA, 16 U.S.C. §§1451-1466. *See*, *e.g.*, Charles R. Sensiba & Sharon L. White, *Hydropower Licensing Under the Federal Power Act: A Century of Resource Conflict Resolution in the Public Interest*, 31 Nat. Resources & Env't 27 (2016).
40. 42 U.S.C. §4332(2)(C).
41. 18 C.F.R. §380.6 (2017).
42. *See* Scenic Hudson Pres. Conference v. Federal Power Comm'n, 354 F.2d 608 (2d Cir. 1965).
43. 43 U.S.C. §§1701-1785, ELR Stat. FLPMA §§102-603.
44. 33 U.S.C. §1341.
45. *Id.* §1341(a)(1).
46. S.D. Warren Co. v. Maine Bd. of Envtl. Prot., 547 U.S. 370, 374, 36 ELR 20089 (2006).
47. 33 U.S.C. §1341(d); American Rivers v. Federal Energy Regulatory Comm'n, 129 F.3d 99, 28 ELR 20258 (2d Cir. 1997).
48. Public Util. Dist. No. 1 of Jefferson Cty. v. Washington Dep't of Ecology, 511 U.S. 700, 24 ELR 20945 (1994).
49. 16 U.S.C. §1536(a)(2).
50. *See*, *e.g.*, FERC, Report on the Pilot Two-Year Hydroelectric Licensing Process for Non-Powered Dams and Closed-Loop Pumped Storage Projects and Recommendations Pursuant to Section 6 of the Hydropower Regulatory Efficiency Act of 2013, at 43 (2017) ("The formal [ESA] consultation process can be lengthy and can hinder [FERC]'s ability to issue a license in a timely manner."), *available at* https://www.ferc.gov/legal/staff-reports/2017/final-2-year-process.pdf.
51. 16 U.S.C. §1456(c)(3)(A).

FERC to consult with federal and state agencies and Indian tribes and take into account any effect of a relicensing on properties that are listed in, or eligible for listing in, the National Register of Historic Places.[52]

C. *Potential for Expansion of Nonfederal Hydropower in the United States*

Hydropower is a critical energy resource, and there is significant potential to expand hydropower development in the United States to meet future demand and reduce dependency on fossil fuels. Successful expansion of hydropower will depend on regulatory reform and new hydropower technologies to develop projects at lower costs and with improved environmental performance. In the near term, the hydropower industry is focused on efficiency upgrades and modernization at existing hydropower projects and new project development at existing non-powered dams. DOE estimates that by 2030, up to 9.4 GW of new conventional hydropower generation in the United States can be installed through project upgrades and powering non-powered dams.[53] Through 2050, moreover, DOE estimates that another 3.4 GW of new conventional generation can be added through project upgrades and powering non-powered dams.[54] In the longer term, there is vast potential to develop hydropower technology at low-head water conveyance systems such as irrigation canals and conduits, expand pumped storage for both generation and storage benefits, and develop MHK into a commercially feasible source of hydropower generation.

1. Upgrades and Optimization of Existing Conventional Projects

Upgrades to the existing fleet of hydropower assets are the low-hanging fruit of potential hydropower growth opportunities. Existing hydropower projects require maintenance to avoid potential degradation of capacity or generation, and provide opportunities for increased production and environmental performance through upgrades and operational adjustments. Federal and nonfederal operators may choose to refurbish or replace turbines and generators, upgrade their water conveyance systems to increase generation efficiency, or modify impoundment structures to increase hydraulic head.[55] Operators may also modify the dispatch of units at a plant and coordinate the operation of plants within a river basin to increase generation without any physical modifications at all.[56] DOE modeled 1,799 hydropower plants in the United States and found 6,856 megawatts (MW) of potential expansion opportunity, or a growth potential of about 9%.[57] DOE also found that upgrades at existing facilities were the lowest-cost option for hydropower expansion.[58]

2. New Hydropower Development at Existing Non-Powered Dams

Installation of hydropower facilities at existing non-powered dams is another expansion opportunity with vast potential. Of the 87,000 existing dams in the United States, only 3% have hydropower generating capability.[59] These dams serve a number of purposes, including water supply, irrigation, and flood control. Hydropower development at existing non-powered dams is an attractive option because most infrastructure needed is already in place, and the costs and environmental impacts of dam construction have already been incurred. Thus, installation of generating equipment can be achieved with fewer costs and environmental impacts, and in a shorter time frame than new dam construction.[60]

Certainly, not all existing dams are candidates for hydropower development. Environmental considerations, economic and technical feasibility, site and transmission access, and the age and condition of existing infrastructure are among the many factors that gauge whether an existing dam is a strong candidate for hydropower development. Despite these considerations, a DOE investigation conducted in 2012 found potential to add up to 12 GW of new generating capacity at existing non-powered dams. A majority of this potential is at Corps dams, many of which are at navigation locks on the Ohio, Mississippi, Alabama, and Arkansas Rivers and their tributaries, and at Bureau of Reclamation dams.[61]

The Corps and the Bureau of Reclamation operate hundreds of non-powered dams and other water infrastructure facilities across the United States. Both of these agencies may authorize nonfederal development at their facilities. In certain instances, the U.S. Congress authorizes construction of a federal dam and reserves exclusive authority to the federal government to develop the hydropower resources at the dam; in other instances, Congress does not include such a reservation.[62] Where Congress does not reserve federal authority to develop hydropower resources at a federal dam, the site may be open to development by nonfederal entities, subject to FERC's jurisdiction under the FPA.[63] FERC and the Bureau of Reclamation have entered into a memorandum of understanding (MOU) that establishes criteria and guidelines for determining whether a proposed

52. 54 U.S.C. §306108.
53. Hydropower Vision, *supra* note 7, at 4. This includes upgrades to federal hydropower projects as well as upgrades to nonfederal hydropower subject to FERC jurisdiction or Bureau of Reclamation lease of power privilege (LOPP) authority.
54. *Id.*
55. *Id.* at 247-48.
56. *Id.* at 248.
57. *Id.* at 251.
58. *Id.* at 251, 255.
59. *Id.* at 11.
60. Assessment of Energy Potential at Non-Powered Dams, *supra* note 17, at vii.
61. *Id.* at vii-viii.
62. *See, e.g.*, Uncompahgre Valley Water Users Ass'n v. Federal Energy Regulatory Comm'n, 785 F.2d 269 (10th Cir. 1986).
63. *See* 16 U.S.C. §§797(e), 817(1).

nonfederal project at a Bureau of Reclamation facility is subject to FERC's jurisdiction.[64]

Hydropower development at Corps dams requires a FERC license, a Corps dredge and fill permit under §404 of the CWA,[65] and permission to modify the dam under the Rivers and Harbors Act of 1899.[66] The Corps and FERC have entered into several agreements intended to coordinate and expedite these regulatory approvals.[67] Hydropower development at Bureau of Reclamation facilities requires either a lease of power privilege (LOPP) or a FERC license.[68] Pursuant to a 1992 MOU between the Bureau of Reclamation and FERC,[69] if the authorizing statute reserves hydropower development exclusively to the United States or withdraws FERC's jurisdiction, the Bureau of Reclamation has jurisdiction over the development through an LOPP. Bureau of Reclamation dams not authorized for federal hydropower development must be authorized by a FERC license. All development of nonfederal hydropower on Bureau of Reclamation conduits are exempt from FERC jurisdiction and require an LOPP.[70]

The Hydropower Regulatory Efficiency Act of 2013 (HREA) included provisions to encourage the addition of hydropower facilities at existing dams. Congress directed FERC to investigate the feasibility of issuing a license for hydropower development at non-powered dams in a two-year period, including FERC's prefiling consultation requirements. After gathering public comments and recommendations, FERC issued a notice soliciting projects to participate in a two-year licensing process.

To qualify, the project must be located at a non-powered dam (or closed-loop pumped storage project), have a well-developed project proposal, cause little to no change to environmental resources, and be located in an area where there is substantial existing information on environmental resources and effects. Only one project was found to meet these criteria, and FERC issued a license within two years.[71] In its report to Congress in May 2017, FERC concluded that a more abbreviated licensing process would be challenging for most projects unless they are located at an ideal site, have a well-defined project proposal, are based on a thorough prefiling consultation, and involve the submission of a complete application.[72]

3. Low-Head Conduit Projects

Low-head conduit hydropower projects are constructed on existing water conveyance structures, such as irrigation canals or pressurized pipelines that deliver water to municipalities, industry, or agricultural water users, without the need to construct new dams or diversions.[73] Water is typically conveyed through open canals and ditches through the force of gravity. To reduce damage from erosion or to reduce pressure in pipelines, devices such as pressure-reducing valves and canal drops[74] are often installed to dissipate excess energy in the structure. Small hydropower turbines can, in some instances, be installed near these devices to harvest electric energy from the conduit. There are many thousands of miles of previously constructed conduits in the United States, and hydropower development in these structures is an untapped source of new renewable energy for the nation.

Congress has enacted provisions to promote hydropower development in nonfederal conduits and to streamline the regulatory process to authorize it. As part of the HREA, certain qualifying conduit hydropower facilities under 5 MW are not subject to FERC jurisdiction and require no FERC license or exemption.[75] Enactment of the HREA was the first instance in which Congress relaxed regulatory requirements to promote hydropower development. To qualify, the facility must use "only the hydroelectric potential of a non-federally owned conduit" that is "operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity."[76] A qualifying facility need only notify FERC of its intent to construct such a facility; if FERC concurs that it qualifies, it will issue a determination within 60 days.[77] While the CWA and other permits are still required, there are no process costs or delays in the federal licensing and permitting of these facilities. In just the first three years since HREA's passage in 2013, FERC

64. *See* Memorandum of Understanding Between the Federal Energy Regulatory Commission and the Bureau of Reclamation Department of the Interior for Establishment of Processes for the Early Resolution of Issues Related to the Timely Development of Non-Federal Hydroelectric Power at Bureau of Reclamation Facilities (1992), https://www.ferc.gov/legal/mou/mou-6.pdf.
65. 33 U.S.C. §1344.
66. *Id.* §408.
67. In 2010, DOE, DOI, and the Corps entered into an MOU intended to increase hydropower project development at federal facilities and on federal lands. *See* Memorandum of Understanding for Hydropower Among the Department of Energy, the Department of the Interior, and the Department of the Army (2010) [hereinafter Energy, Interior & Army MOU], https://energy.gov/sites/prod/files/2015/02/f19/Memorandum%20of%20Understanding%20for%20Hydropower%20March%202010.pdf. In 2011, FERC and the Corps entered into an MOU to facilitate the development of hydropower at Corps facilities by coordinating the agencies' permitting processes. *See* Memorandum of Understanding Between United States Army Corps of Engineers and the Federal Energy Regulatory Commission on Non-Federal Hydropower Projects (2011), https://www.ferc.gov/legal/mou/mou-usace.pdf. This MOU was updated in 2016. *See* News Release, FERC & Office of the Assistant Secretary of the Army, FERC, U.S. Army Corps of Engineers Sign MOU on Hydropower Development (July 21, 2016), https://www.ferc.gov/media/news-releases/2016/2016-3/07-21-16-A-3.pdf.
68. An LOPP is a contractual right given to a nonfederal entity to use a Bureau of Reclamation dam or conduit for electric power generation purposes.
69. *See supra* note 64.
70. *See* Pub. L. No. 113-24, §2, 127 Stat. 498 (2013).
71. FFP Project 92, LLC, 155 FERC ¶ 62089 (2016).
72. FERC, *supra* note 50, at iii.
73. DOE, Pumped Storage and Potential Hydropower From Conduits, Report to Congress iii (2015), *available at* http://energy.gov/sites/prod/files/2015/06/f22/pumped-storage-potential-hydropower-from-conduits-final.pdf.
74. A canal drop structure reduces the bottom slope of an irrigation canal lying on steeply sloping land to avoid high velocity of the flow and risk of erosion.
75. In the 115th Congress, the full U.S. House of Representatives passed a bill that would remove the 5-MW cap for these facilities, which, if enacted, would remove most conduit facilities from FERC's jurisdiction under the FPA. *See* H.R. 2786, 115th Cong. (introduced June 6, 2017).
76. HREA §4(a)(1), 127 Stat. at 494.
77. *See* 18 C.F.R. §§4.400 et seq. (2017).

has found that 83 proposed conduit hydropower facilities have qualified for this program.[78]

If a conduit hydropower facility does not meet the criteria for a qualifying conduit hydropower facility, FERC can issue a conduit "exemption" (a FERC authorization that is similar to a license or permit) for facilities under 40 MW. To qualify, the project must use only the hydroelectric potential of a conduit that is "operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity."[79] The process of obtaining an exemption is less time-consuming and expensive than the FERC licensing process. These exemptions are issued in perpetuity and do not require reauthorization. Any conduit hydropower facilities that do not meet the criteria as a qualifying conduit hydropower facility or otherwise qualify for a conduit exemption require a FERC license to operate.[80]

Congress has also passed legislation to promote hydropower development at federal conduit facilities. In August 2013, it passed the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act,[81] which authorizes all small (5 MW and under) Bureau of Reclamation conduit facilities for hydropower development. This legislation shifted jurisdiction for the approval of such facilities from FERC to the Bureau of Reclamation. An LOPP is required to authorize hydropower in a Bureau of Reclamation conduit, but the regulatory process is streamlined under the legislation because such projects are categorically exempted from NEPA review. The Bureau of Reclamation found in a March 2012 report that more than 373 of its existing canals and conduits have the potential for hydropower generation of more than 365,000 MW hours annually.[82]

4. Pumped Storage Projects

Pumped storage hydropower has a long history of providing cost-effective and operationally flexible generation to the grid. Currently, it is the only commercially proven technology available for grid-scale energy storage (though other options are emerging).[83] These projects offer black start capability, in the event of a widespread blackout, and can come online very quickly without an external power source. Pumped storage projects also provide essential ancillary services to the grid, including network frequency control and reserve generation, to support the integration of variable renewable resources, such as wind and solar.

There are two varieties of pumped storage hydroelectric projects. Pumped storage plants that are continuously connected to a naturally flowing water feature are referred to as "open-loop" projects. Plants that are not continuously connected hydraulically to a naturally flowing water feature are called "closed-loop" projects.[84] While pumped storage plants generally consume more energy than they produce, they provide important benefits that no other energy resource can offer.

There are currently 40 pumped storage plants in operation in the United States with a combined capacity of 21.6 GW, accounting for 95% of all energy storage capacity in the power grid.[85] On a global scale, there are approximately 270 pumped storage projects operating and under construction, with a combined generating capacity of more than 127 GW.[86] Much of the recent focus in pumped storage development is on closed-loop systems, which generally have fewer environmental effects than open-loop systems.

5. MHK Projects

Hydrokinetic technologies have tremendous potential to add to hydropower's contribution to overall decarbonization. DOE estimates that electrical generation from MHK projects in U.S. waters[87] has the potential to generate 1,700 terawatt hours[88] per year if fully developed, which would power 15.7 million homes and avoid nearly 1.2 billion metric tons of CO_2 emissions annually.[89] River hydrokinetic power, which can be captured through in-water devices that capture the natural flows of rivers and streams, does not require impoundment, and has the potential to replace diesel generation in isolated communities, such as those in rural Alaska.[90]

At this time, however, MHK is still considered an emerging industry, with efforts focused on research and development toward making it technologically and economically viable.[91] Hydrokinetic projects face unique and significant challenges in siting, costs, and technology to withstand the harsh conditions in oceans and rivers, as well as in obtain-

78. FERC, *supra* note 50, at ii.
79. 16 U.S.C. §823a(a)(3)(A).
80. *See*, *e.g.*, ECOsponsible, Inc., 147 FERC ¶ 61052, at P 9-10 (2014) ("[T]he proposed project is not a 'qualifying conduit hydropower facility.' . . . We note that this holding in no way precludes [ECOsponsible, Inc.] from pursuing the development of its project pursuant to the FPA.").
81. Pub. L. No. 113-24, 127 Stat. 498 (2013).
82. Bureau of Reclamation, DOI, Site Inventory and Hydropower Energy Assessment of Reclamation Owned Conduits 6 (2012), *available at* https://www.usbr.gov/power/CanalReport/FinalReportMarch2012.pdf.
83. *See* Alexandra B. Klass, *Expanding the U.S. Electric Transmission and Distribution Grid to Meet Deep Decarbonization Goals*, 47 ELR 10749 (Sept. 2017).
84. *See*, *e.g.*, Wyco Power & Water, Inc., 139 FERC ¶ 61124, at P 12 n.11 (2012).
85. DOE, *supra* note 73, at ii.
86. Pumped Storage Development Council, National Hydropower Association, Challenges and Opportunities for New Pumped Storage Development 13, *available at* http://www.hydro.org/wp-content/uploads/2014/01/NHA_PumpedStorage_071212b12.pdf.
87. Office of Energy Efficiency and Renewable Energy, DOE, Marine and Hydrokinetic Energy Projects—Fiscal Years 2008-2015 (2016) (DOE/EE-0710), *available at* http://energy.gov/sites/prod/files/2016/02/f29/MHK-Projects-Report-2-1-16.pdf.
88. A terawatt is equivalent to 1,000,000 MWs. A terawatt hour is equivalent to 1,000,000 MWs of electricity generated continuously for one hour.
89. *See supra* note 21.
90. *See The Alaskan Way*, Int'l Water Power & Dam Construction, Sept. 27, 2011, http://www.waterpowermagazine.com/features/featurethe-alaskan-way; Campbell Scientific, Case Study No. 102, Alaska: Hydrokinetic Energy (2015), *available at* https://s.campbellsci.com/documents/au/case-studies/102Alaska-hydrokinetic-energy.pdf.
91. *See* DOE Office of Energy Efficiency and Renewable Energy, *Marine and Hydrokinetic Energy Research & Development*, https://energy.gov/eere/water/marine-and-hydrokinetic-energy-research-development (last visited Dec. 11, 2017).

ing the necessary authorizations to build such projects. Both FERC and DOE have implemented programs to promote the development of hydrokinetic projects and help to overcome these challenges.

FERC has unveiled a number of initiatives over the past 12 years to help promote the development of hydrokinetic technologies by lowering the regulatory barriers to permitting such projects. In 2005, for example, FERC created an exception to its licensing requirement for the short-term testing of MHK technology in certain circumstances, when power generated from the device was not transmitted to the electric grid.[92]

In 2007, FERC staff introduced a new pilot licensing process for small-scale hydrokinetic projects to allow developers to test new hydrokinetic technologies, including connection with the interstate grid, on an expedited time line.[93] Projects utilizing the pilot licensing process must be small (under 5 MW) and able to be shut down or removed on short notice, and must not be located in sensitive areas. The pilot process contemplates licensing of such projects in as little as six months, though in practice FERC has taken far longer to issue pilot licenses. The pilot licenses issued thus far have been subject to significant environmental monitoring and safety requirements, and have been issued for license terms up to 10 years.

FERC has also issued a policy supporting the issuance of conditioned licenses for MHK projects in certain cases, which would enable the licensee to receive the license prior to obtaining other federal authorizations for the project, conditioned on receipt of such other authorizations prior to commencing construction.[94]

In addition, FERC has made strides to resolve the confusion for developers caused by the overlap in jurisdiction between FERC and the Bureau of Ocean Energy Management (BOEM) for hydrokinetic projects on the Outer Continental Shelf (OCS). The agencies signed an MOU in 2009 providing for dual jurisdiction for hydrokinetic projects on the OCS. Under the MOU, BOEM has exclusive jurisdiction to issue leases, easements, and rights-of-way, and FERC has exclusive jurisdiction to issue licenses and exemptions for such projects. The agencies subsequently issued guidelines to assist developers interested in pursuing MHK development on the OCS.[95]

DOE has also taken action to promote the development of MHK technology. DOE's Water Power Program provides federal incentives to stimulate the deployment of hydrokinetic technology. From fiscal year (FY) 2008 to FY 2015, DOE issued awards totaling about $136 million for 92 MHK projects in 24 states.[96] These funding opportunities fall under two activity areas—technology development and market acceleration and deployment—and are awarded to a variety of entities, including private industry, nonprofit organizations, educational institutions, investor-owned utilities and public utilities, and local and state governments.[97] DOE also offers loan guarantees to help developers secure financing for MHK technology and testing.

6. Preserving the Existing Fleet

To continue hydropower's contributions to U.S. renewable generation, efforts must also be made to preserve the existing fleet. Between 2016 and 2030, more than 500 projects will begin the FPA-required relicensing process. This represents about one-half of all hydropower projects licensed by FERC, and about 30% of the total hydropower licensed capacity under FERC's jurisdiction.[98] The vast majority of these projects are very small; the median installed capacity of the projects is 2.5 MW. The prospect of incurring the high cost and requirements of relicensing is likely to cause some project owners to determine that the cost of continuing to operate the project exceeds its benefit, and therefore to decommission the project rather than seek a new license.[99] Efforts to modernize regulatory oversight while preserving modern environmental standards will help to keep project owners invested in continued operation of these projects.

III. Resolving Impediments to Hydropower Development Through Legal Reform

As explained in Part II of this Article, many of the current impediments for capturing the significant potential to preserve and expand hydropower in the United States can be traced to the regulatory framework governing the licensing and oversight of these generating facilities. In many respects, the hydropower licensing program under the FPA—enacted nearly a century ago in the Federal Water Power Act (FWPA) of 1920[100]—has been a tremendous

92. Verdant Power LLC, 111 FERC ¶ 61024, *order on clarification*, 112 FERC ¶ 61143 (2005).
93. FERC, Licensing Hydrokinetic Pilot Projects (2008), *available at* https://www.ferc.gov/industries/hydropower/gen-info/licensing/hydrokinetics/pdf/white_paper.pdf.
94. Policy Statement on Conditioned Licenses for Hydrokinetic Projects, 72 Fed. Reg. 68877 (Dec. 6, 2007).
95. BOEM/FERC Guidelines on Regulation of Marine and Hydrokinetic Energy Projects on the OCS (Version 2 2012), *available at* https://www.ferc.gov/industries/hydropower/gen-info/licensing/hydrokinetics/pdf/mms080309.pdf.
96. Office of Energy Efficiency and Renewable Energy, *supra* note 87, at 30-31.
97. *Id.* at 29.
98. *Hearing on Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination Under the Natural Gas Act Before the House Comm. on Energy and Commerce, Subcomm. on Energy and Power*, 114th Cong. 8 (2015) (testimony of Ann Miles, FERC), https://www.ferc.gov/CalendarFiles/20150513110741-Miles-testimony-05-13-2015.pdf.
99. *See* Project Decommissioning at Relicensing; Policy Statement, 60 Fed. Reg. 339, 347 (Jan. 4, 1995) (codified at 18 C.F.R. §2.24); PacifiCorp, 133 FERC ¶ 61232 (2010), *order on reh'g*, 135 FERC ¶ 61064 (2011) (order accepting surrender of license after licensee determined that environmental costs under new license were economically unacceptable); Portland Gen. Elec. Co., 107 FERC ¶ 61158 (2004) (order accepting surrender of license after licensee determined that environmental costs associated with relicensing would make continued operation uneconomical); Pacific Gas and Electric Co.'s License Surrender Application for the Kilarc-Cow Creek Hydro Project, Project No. 606-027 (filed Mar. 12, 2009).
100. Pub. L. No. 66-280, ch. 285, 41 Stat. 1063 (codified at 16 U.S.C. §§791a et seq.).

success.[101] At a time when our nation's electric power-generating infrastructure was in its infancy with pressure to expand, Congress in 1920 created the Federal Power Commission (FPC), FERC's predecessor agency,[102] to facilitate decisionmaking by a single administrative body that was statutorily charged to balance multiple (and sometimes competing) uses of our nation's waterways for purposes of power development, recreation, navigation, aquatic resources, and other public interests.[103]

The emergence of modern environmental requirements—through both the enactment of federal environmental programs such as NEPA, the ESA, and the CWA, as well as amendments to the FPA itself—has resulted in significant procedural and substantive changes in the licensing of nonfederal hydropower. Substantively, modern nonfederal hydropower licensing involves a much more rigorous investigation of environmental effects of the project, with focused emphasis on protection of, mitigation of effects to, and enhancement of resources such as affected aquatic and terrestrial species,[104] water quality,[105] federal land use planning,[106] cultural resources,[107] and coastal zones.[108] While FERC licensing of most nonfederal hydropower remains intact, the single-agency decisional model originally conceived by Congress when enacting the FWPA nearly a century ago has been replaced by today's highly complex licensing scheme that involves consultation, oversight, and regulatory authorities exercised by multiple federal and state resource agencies. As such, FERC's statutory duty to consider and balance the full spectrum of competing resources in the public interest, as required by the FPA, has largely been compromised and replaced by requirements mandated by many different agencies with more focused management priorities.[109]

From a procedural standpoint, the regulatory evolution in nonfederal hydropower to a multiple-agency process has given rise to a protracted and cumbersome licensing process that lacks central coordination. In modern nonfederal hydropower licensing, FERC has limited ability to maintain regularity and efficiency in the licensing process.[110] The result is a regulatory structure that features redundancy in environmental studies and NEPA review; competing and often conflicting regulatory requirements due to overlapping authorities among agencies[111]; and a FERC licensing process that can take a decade to complete[112]—only to repeat a similar approval process before other agencies for other permits and approvals needed for project development, without any societal benefits from this redundant regulatory structure.

These procedural and substantive features in nonfederal hydropower licensing impose a significant disadvantage to hydropower in the marketplace, as compared to other electricity-generation sources. Due to engineering and construction requirements, hydropower inherently faces high front-end development costs (with its value increasing over time due to the lack of fuel costs). When coupled with the current lengthy, expensive, and overlapping regulatory approval process, other generation sources—typically fossil fuel resources such as natural gas, which offer some of the grid benefits of hydropower such as peaking power, load following, and integration of intermittent renewables—often are more attractive than hydropower. Too often, the result is a lost opportunity to capture renewable, non-emitting energy—even at existing non-powered dams where hydropower could be retrofitted to complement ongoing use of existing infrastructure (e.g., water supply dams and flood control facilities).

Policymakers have developed a number of options to address these significant regulatory impediments to hydropower while maintaining environmental standards. These solutions, described in detail in the sections that follow, range from facilitating greater coordination

101. Sensiba & White, *supra* note 39, at 27.
102. Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (1977).
103. FWPA §10(a), 41 Stat. at 1068; Gifford Pinchot, *The Long Struggle for Effective Water Power Regulation*, 14 Geo. Wash. L. Rev. 9 (1945).
104. 16 U.S.C. §1536 (§7 of the ESA); *id*. §803(j) (§10(j) of the FPA); *id*. §811 (§18 of the FPA); *id*. §1855(b)(2) (§305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act); *id*. §1372 (§102 of Marine Mammal Protection Act).
105. 33 U.S.C. §§1341, 1344 (§§401 and 404 of the CWA).
106. 16 U.S.C. §797(e) (§4(e) of the FPA); 43 U.S.C. §1761 (FLPMA).
107. 54 U.S.C. §306108 (§106 of the NHPA).
108. 16 U.S.C. §1456(c)(3)(A) (§307(c)(3)(A) of the CZMA).
109. Charles R. Sensiba, *Who's in Charge Here? The Shrinking Role of the Federal Energy Regulatory Commission in Hydropower Relicensing*, 70 U. Colo. L. Rev. 603 (1999); Charles R. Sensiba, *Hydropower*, *in* The Law of Clean Energy: Efficiency and Renewables 479, 480-83 (Michael B. Gerrard ed., ABA 2011).
110. *See* City of Tacoma v. Federal Energy Regulatory Comm'n, 460 F.3d 53, 65, 36 ELR 20173 (D.C. Cir. 2006) (holding that FERC cannot set "strict time restriction[s]" on mandatory conditioning agencies). In addition, while §401 of the CWA requires a state agency to act on a request for water quality certification within one year after receipt of an application, states frequently insist that the applicant withdraw and refile its application before the one-year deadline, sometimes numerous times, to give the state additional time to act. *See* PacifiCorp, 149 FERC ¶ 61038, at P 20 (2014) (noting that states that engage in repeated withdrawal and refiling of applications for water quality certification cause delays in the issuance of new licenses); FERC, Report on Hydroelectric Licensing Policies, Procedures, and Regulations Comprehensive Review and Recommendations Pursuant to Section 603 of the Energy Act of 2000, at 16-17 (2001) [hereinafter 603 Report], *available at* https://www.ferc.gov/legal/maj-ord-reg/land-docs/ortc_final.pdf. In addition, though FWS and NMFS regulations require them to conclude formal ESA consultation through the issuance of a BiOp within 135 days, 16 U.S.C. §1536(b)(3)(A); 50 C.F.R. §402.14(e), this deadline is commonly exceeded, causing hydropower licensing to be delayed.
111. *See*, *e.g.*, Letter From Ann F. Miles, Director, Division of Hydropower, FERC, to Steven M. Pirner, Department Secretary, South Dakota Department of Environment and Natural Resources (Aug. 10, 2009) (Project No. 12775-001) (noting that the federal and state agencies had submitted conflicting mandatory conditions and asking the agencies to resolve the conflict); Puget Sound Energy, Inc., 107 FERC ¶ 61331 (2004), *order on reh'g*, 110 FERC ¶ 61200, *reh'g denied*, 111 FERC ¶ 61317 (2005), *aff'd*, Snoqualmie Indian Tribe v. Federal Energy Regulatory Comm'n, 545 F.3d 1207 (9th Cir. 2008) (FERC imposed greater minimum flow requirements than those required by the state water quality certification).
112. 603 Report, *supra* note 110, at 31 (noting that the average processing time from application to license issuance is 52 months). *See also Hearing to Receive Testimony on Opportunities to Improve American Energy Infrastructure Before the Senate Comm. on Energy and Natural Resources*, 114th Cong. 5 (2017) (written testimony of Jeffrey Leahey, Deputy Executive Director, on Behalf of the National Hydropower Association), https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=E3BD2A82-1B13-4B5F-8754-46C181EACB60.

among FERC and other agencies, to ensuring that decisionmakers account for the climate benefits of hydropower in their licensing and permitting decisions. These solutions would also ensure that renewable energy incentives, goals, and requirements include the full range of hydropower, and would help develop critical information to better inform market participants and regulators of the grid benefits provided by hydropower resources, and particularly pumped storage.

A. *Fully Recognize Hydropower as a Renewable Energy Resource*

Our ability to more fully capture hydropower's potential to assist in a deep decarbonization effort must begin with policies that attempt to level the regulatory playing field between hydropower and other resources. As described below, federal and state policies relating to renewable energy treat hydropower very differently than other renewable generation resources, such as solar, wind, and geothermal, by significantly reducing the classes of hydropower that qualify for renewable energy programs—or by excluding hydropower altogether. Because such policies make sweeping and rather arbitrary judgments related to hydropower's environmental effects, state and federal policymakers should revisit their policies by recognizing that the main thrust of these programs is to displace carbon-based generation, and that the most effective means of ensuring that goal in an environmentally responsible manner is to rely on the comprehensive and rigorous environmental review by FERC and other federal and state resource agencies under the suite of federal laws, such as the FPA, the ESA, the CWA, the CZMA, and the NHPA. In other words, if a hydropower project can be licensed to meet these rigid requirements, it should receive full recognition as a renewable resource.

A number of federal and state renewable energy policies treat hydropower differently than other renewable sources. When establishing renewable energy procurement requirements for the federal government, for example, the Energy Policy Act of 2005 (EPAct 2005) included hydropower only with respect to ocean MHK technologies and "hydroelectric generation capacity achieved from increased efficiency or additions of new capacity at an existing hydroelectric project."[113] This definition excludes from federal renewable energy procurement the entire existing fleet of 2,198 hydropower projects across the United States totaling 101 GW of capacity.[114] It also eliminates any incentive to meet federal renewable energy requirements through developing new hydropower facilities at existing non-powered dams, along water supply conduits, irrigation canals, or other infrastructure, or at environmentally responsible greenfield sites.[115]

Other federal and state policies are just as exclusionary—some more so. Of all the resources defined as "renewable electric energy" in Executive Order No. 13693 (which establishes federal facility requirements for sustainability and emissions reductions, including utilization of renewable electric energy), the only resource that contains any limited applicability is hydropower. The Executive Order defines "renewable electric energy" as

> energy produced by solar, wind, biomass, landfill gas, ocean (including tidal, wave, current, and thermal), geothermal, geothermal heat pumps, microturbines, municipal solid waste, or new hydroelectric generation capacity achieved from increased efficiency or additions of new capacity at an existing hydroelectric project.[116]

The U.S. Environmental Protection Agency's (EPA's) Green Power Partnership (a voluntary program of organizations that use a percentage of their annual electricity from green power and report their green power use to EPA) places similar restrictions on qualifying hydropower projects by narrowly defining hydropower:

> Hydropower is eligible if it meets one or more of the following conditions:
>
> a. Hydropower facilities certified by the Low Impact Hydropower Institute
>
> b. New incremental capacity on a non-impoundment or "new" generation capacity on an existing impoundment that is a run-of-the-river hydropower facility
>
> c. Hydropower facilities that consist of a turbine in a pipeline or a turbine in an irrigation canal
>
> . . .
>
> EPA will consider new incremental capacity on an existing dam on a case-by-case basis, where the "new" output is equal to or less than 5 megawatts.[117]

Similarly, a 2012 MOU between the U.S. Departments of Defense (DOD) and the Interior (DOI) includes a stated purpose of helping "DoD develop renewable energy in the interests of greater installation energy security and reduced installation energy costs. . . ."[118] Eligible technologies dis-

113. 42 U.S.C. §15852(b)(2).
114. Hydropower Vision, *supra* note 7, at 78.
115. One example highlights the current problem. In 2012, the Corps issued Large Scale Renewable and Alternative Energy Production for Federal Installations, Solicitation No. W912DY-11-R-0036, which estimated a $7 billion maximum value of all contracts awarded under the proposal. Despite the urging of the hydropower industry, hydropower was completely excluded from the proposal. *See* Letter From Linda Church Ciocci, Executive Director, National Hydropower Association, to Sarah Tierney, U.S. Army Engineering and Support Center (Mar. 21, 2012), http://www.hydro.org/wp-content/uploads/2012/03/NHA-Comments-Large-Scale-Renewable-Energy-Production-for-Federal-Installations-No-W912DY-11-R-0036.pdf.
116. Exec. Order No. 13693, 80 Fed. Reg. 15869, 15883 (Mar. 25, 2015).
117. U.S. EPA, EPA's Green Power Partnership, Partnership Requirements, app. A, at A-1 (2017), *available at* https://www.epa.gov/sites/production/files/2016-01/documents/gpp_partnership_reqs.pdf.
118. Memorandum of Understanding Between the Department of Defense and the Department of the Interior on Renewable Energy and a Renewable Energy Partnership Plan 1 (2012), https://www.acq.osd.mil/dodsc/library/DoD_DOI%20MOU%20Signed%2020%20Jul%202012.pdf.

cussed in the MOU include wind, solar, geothermal, and biomass. Hydropower is not included in the MOU. While touching on energy storage technologies, moreover, the MOU does not recognize pumped storage—the only utility-scale energy storage technology currently available. The MOU discusses offshore wind potential on the OCS, but does not discuss MHK assessments conducted by DOE.

Finally, while many states with renewable portfolio standards (RPS) allow some forms of hydropower to qualify, most include restrictions based on the capacity of the project and the age of the facility. Some states impose additional restrictions based on operation requirements of the facility, environmental considerations, and technology.[119] By way of example, Arizona only counts hydropower that is

> installed after January 1, 2006, that produces 10 MW or less and is either:
>
> a. A low-head, micro hydro run-of-the-river system that does not require any new damming of the flow of the stream; or
>
> b. An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or
>
> c. Generation using canals or other irrigation systems.[120]

California's RPS for hydropower is quite complex and allows only the following categories of facilities to qualify, most of which must have been in operation prior to 2006:

> (1) Small hydroelectric facilities 30 MW or less.
>
> (2) Conduit hydroelectric facilities 30 MW or less.
>
> (3) Hydroelectric generation units 40 MW or less and operated as part of a water supply or conveyance system.
>
> (4) Incremental hydroelectric facilities.[121]

Even within this narrow list of potentially eligible hydropower categories, California's RPS imposes additional qualification restrictions, such as the presence of other hydropower projects in the vicinity, impacts on stream use, and whether the project is located within or outside of California.[122]

In Connecticut, the RPS only allows

> a run-of-the-river hydropower facility that began operation after July 1, 2003, and has a generating capacity of not more than thirty megawatts, provided a facility that applies for certification under this clause after January 1, 2013, shall not be based on a new dam or a dam identified by the commissioner as a candidate for removal, and shall meet applicable state and federal requirements, including applicable site-specific standards for water quality and fish passage. . . .[123]

These exclusions and limitations of hydropower in renewable energy programs demonstrate that policymakers arbitrarily screen hydropower from these programs based on an environmental standard—a standard that is not imposed on other renewable generation resources, even though no energy project is without environmental effects. There is no uniformity among states as to how those impacts should be addressed in RPS standards. Moreover, the limitations imposed in these programs—while perhaps rooted in a concern over environmental impacts associated with hydropower—are flawed for two primary reasons.

First, these programs impose sweeping and inconsistent limitations on hydropower based on general assumptions related to environmental effects. In Arizona, for example, a 9-MW low-head, run-of-river project that does not require any new dam would qualify for the state's RPS, while a 12-MW project meeting those exact same criteria would not. In California, a 25-MW conduit hydropower project constructed in 2005 may qualify for the state's RPS, while a 35-MW project constructed at the same site 10 years later is unlikely to qualify. In Connecticut, a 15-MW run-of-river project would qualify for the state's RPS, but the exact same project would not be eligible for EPA's program. And none of these projects would qualify as renewable energy for federal procurement under EPAct 2005.

Second, the coarse environmental requirements imposed by these programs ignore the rigorous and comprehensive environmental review and resulting operating requirements imposed by the FPA and other applicable federal programs. The entire purpose of the licensing process under the FPA, together with the full suite of environmental requirements of other federal programs (which were enacted after many dams in the United States were already constructed), is to evaluate the environmental effects of a project on an individual basis—regardless of its size, operating regime, date of construction, or location—and to develop an operating regime and other requirements that protect, mitigate effects of, and even enhance environmental resources. Hydropower projects meeting these rigid environmental and public interest requirements should not be excluded from a state RPS or other renewable energy program simply because they exceed an arbitrary capacity limit or are not a preferred technology.

Thus, as we look for solutions to deepen our reliance on non-carbon energy sources, federal and state policy-

119. For a general survey of treatment of hydropower in state RPS requirements, see Val Stori, Clean Energy States Alliance, Environmental Rules for Hydropower in State Renewable Portfolio Requirements (2013), *available at* https://www.cesa.org/assets/2013-Files/RPS/Environmental-Rules-for-Hydropower-in-State-RPS-April-2013-final-v2.pdf.

120. Ariz. Admin. Code §R14-2-1802(A)(9) (2016), *available at* http://apps.azsos.gov/public_services/Title_14/14-02.pdf.

121. California Energy Commission, Commission Guidebook: Renewables Portfolio Standards Eligibility 14 (2015) (CEC-300-2015-001-ED8-CMF), *available at* http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf.

122. *See generally id.* at 14-21.

123. Conn. Gen. Stat. §16-1(a)(20)(x) (2017), *available at* https://www.cga.ct.gov/current/pub/chap_277.htm#sec_16-1.

makers should amend existing renewable energy programs and develop new such programs recognizing that all duly licensed and environmentally compliant nonfederal hydropower should be considered renewable. In addition to a national RPS standard that includes all forms of duly licensed nonfederal hydropower or a carbon tax, specific solutions include the following actions:

- Congress should amend EPAct 2005 to clarify that all forms of duly licensed nonfederal hydropower satisfy renewable energy requirements for federal procurement.[124]
- The president should revise Executive Order No. 13693 to clarify that all forms of duly licensed nonfederal hydropower meet the definition of "renewable electric energy."
- Through the use of Executive Orders, directives, and memoranda, the Administration should: (1) establish that all duly licensed nonfederal hydropower, in all its forms, is an energy priority and compatible with agency missions, and a renewable energy resource for purposes of meeting climate goals; and (2) direct federal departments, agencies, and bureaus to review and revise any policies, regulations, MOUs, guidance documents, and other governing documents that are inconsistent with this establishment of policy.
- The Administration should direct all federal departments, agencies, and bureaus with responsibilities for the approval of any aspect of hydropower to review, update, and supplement agency guidance documents, handbooks, and resource plans to reflect hydropower as a priority for combating carbon emissions.
- Through the use of federal research grants and other federal funding provided to the states, Congress and federal agencies should encourage the states to change their restrictive RPS requirements by allowing all duly licensed nonfederal hydropower to qualify.

B. *Require All Regulatory Agencies to Give "Equal Consideration" to the Climate Benefits of Hydropower in Their Licensing and Permitting Decisions*

Since their enactment nearly 100 years ago, the hydropower licensing provisions of the FPA have evolved over time to reflect advances in scientific understanding and changes in regulatory policies of the public's use of water resources. As originally enacted in 1920, the statute recognized primarily the public uses of power generation and navigation, requiring the FPC to condition licenses as "best adapted to a comprehensive scheme of improvement and utilization for the purposes of navigation, of water-power development, and of other beneficial public uses. . . ."[125] Fifteen years later, with a growing interest in public recreation in our nation's waterways, Congress responded by expanding the FPC's responsibilities to balance hydropower licenses in the public interest by requiring it to include "recreational purposes."[126]

With more modern recognition and focus on environmental resources, Congress in the Electric Consumers Protection Act (ECPA) of 1986 further expanded FERC's responsibilities, requiring its licensing decisions to balance "the adequate protection, mitigation, and enhancement of fish and wildlife (including related spawning grounds and habitat)," as well as irrigation, flood control, and water supply.[127] In the ECPA, Congress also amended the FPA to emphasize FERC's balancing responsibility when issuing licenses:

> In deciding whether to issue any license under this Part for any project, [FERC], in addition to the power and development purposes for which licenses are issued, shall give equal consideration to the purposes of energy conservation, the protection, mitigation of damage to, and enhancement of, fish and wildlife (including related spawning grounds and habitat), the protection of recreational opportunities, and the preservation of other aspects of environmental quality.[128]

In the most recent expansion of this balancing authority, Congress in EPAct 2005—recognizing the proliferation of "mandatory" licensing conditions imposed by federal and state resource agencies other than FERC[129]—required that agencies exercising mandatory conditioning authority under the FPA[130] also demonstrate through a written statement that they "gave equal consideration to the effects of the condition adopted . . . on energy supply, distribution, cost, and use; flood control; navigation; water supply; and air quality (in addition to the preservation of other aspects of environmental quality). . . ."[131]

As policies and priorities have continued to evolve over the past decade, with increased attention and concern to climate change, Congress could again step in and require

124. This provision is included in the Senate energy bill considered in the 115th Congress, see S. 1460, 115th Cong. §3001(a)(2) (2017), as well as the House hydropower reform bill. *See* H.R. 3043, 115th Cong. §2(b) (2017). H.R. 3043 passed the full House on Nov. 8, 2017.

125. FWPA §10(a), 41 Stat. at 1068 (current version codified at 16 U.S.C. §803(a)(1)).

126. Public Utility Act of 1935, Pub. L. No. 74-333, §206, 49 Stat. 803, 843 (current version codified at 16 U.S.C. §803(a)(1)).

127. Pub. L. No. 99-495, §3(b), 100 Stat. 1243, 1244 (current version codified at 16 U.S.C. §803(a)(1)).

128. *Id.* §3(a), 100 Stat. at 1243 (codified at 16 U.S.C. §797(e)).

129. As discussed *supra* Part II, these include conditions imposed by federal reservation management agencies under FPA §4(e), 16 U.S.C. §797(e), fishway prescriptions imposed by FWS and NMFS under FPA §18, 16 U.S.C. §811, and water quality certification conditions imposed by the states under CWA §401, 33 U.S.C. §1341.

130. 16 U.S.C. §§797(e), 811. Conditions submitted under these authorities are considered "mandatory" because the Supreme Court has held that FERC cannot reject or modify these conditions and prescriptions, and must incorporate them into the FERC license for the project. Escondido Mut. Water Co. v. La Jolla Band of Mission Indians, 466 U.S. 765, 14 ELR 20592 (1984).

131. EPAct 2005 §241(c), 119 Stat. at 676 (adding a new §33 to the FPA, codified at 16 U.S.C. §823d(a)(4), (b)(4)).

FERC, together with federal and state resource agencies exercising authority over hydropower development, to give "equal consideration" to the climate benefits afforded by hydropower.[132] Agencies other than those with mandatory conditioning authority, which are already required to give equal consideration to developmental and nondevelopmental values, also play a significant role in shaping operational requirements of hydropower projects (which have significant effects on a project's ability to generate, follow load, integrate intermittent renewables, and otherwise provide significant climate benefits to the grid).

These agencies issue necessary permits for hydropower development, including dredge and fill permits issued under CWA §404[133] and state water quality certifications under CWA §401.[134] They also require reasonable and prudent measures or alternatives developed during consultation under ESA §7,[135] which are incorporated into a FERC license. While expressly requiring these agencies to give equal consideration to the effects of climate on their decisions affecting hydropower would not dictate their final license conditions,[136] it would ensure that agencies analyze the effects of their actions on climate change, and perhaps lead to more balanced permits and measures that protect hydropower's value as a renewable, non-emitting source of electricity.

C. *Integrate the FERC Licensing Process With Other Regulatory Requirements and Require Greater Coordination and Schedule Discipline*

As described in Part II above, the authorization of nonfederal hydropower is a series of complex, lengthy, and expensive processes before multiple federal and state agencies. FERC's licensing process alone can take 10 years or more to complete,[137] and triggers a number of requirements under NEPA, the ESA, the CWA, the NHPA, the CZMA, and other statutes.[138] Under current law and practice, there are few opportunities to consolidate and coordinate these permitting activities. While agencies' various statutory responsibilities are an important part of the project review process to ensure resource protection and management, there are few mechanisms under current law to coordinate all agencies' programs to reduce duplication of effort, encourage concurrent review and collaboration, and ensure timely action.[139]

The regulations of the Council on Environmental Quality allow for agencies to find efficiencies in the NEPA process by cooperating,[140] "tiering" from prior environmental analyses of other agencies,[141] and issuing supplemental environmental analyses.[142] Other statutes, such as CWA §401, expressly provide that subsequent water quality certifications are unnecessary for the multiple federal authorizations required for a single project or activity.[143] In practice, however, agencies tend not to rely on these opportunities—perhaps because they prefer their own work product over that of other agencies, or they fear that inaction may lead to litigation. FERC, moreover, has a long-standing policy of requiring federal and state resource agencies to choose between participating with FERC as a cooperating agency for NEPA purposes, or protecting its legal rights in the FERC proceeding as an intervenor.[144] While FERC's policy is grounded in public policies prohibiting ex parte communications with parties in a contested proceeding,[145] the effect is to force agencies to decline to participate as a cooperating agency and to conduct their own NEPA review on their own schedule, once the hydropower applicant seeks the required authorization from that agency.

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132. While the reference to "air quality" in FPA §33, 16 U.S.C. §823d, arguably imposes this requirement on agencies exercising mandatory conditioning authorities under FPA §§4(e) and 18 already, these agencies' regulations have narrowly interpreted this responsibility. Resource Agency Hearings and Alternatives Development Procedures in Hydropower Licenses, 81 Fed. Reg. 84389, 84393-94 (Nov. 23, 2016). Congress has responded by introducing legislation in the 115th Congress that would require mandatory conditioning agencies to give equal consideration whenever they exercise their mandatory conditioning authority. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §3(a) (2017). *See also* Sierra Club v. Federal Energy Regulatory Comm'n, 867 F.3d 1357, 1374-75, 47 ELR 20104 (D.C. Cir. 2017) (holding that FERC is required to estimate and consider the potential downstream negative climate impacts when permitting interstate natural gas pipeline projects).
133. 33 U.S.C. §1344.
134. *Id.* §1341.
135. 16 U.S.C. §1536.
136. "Equal consideration" does not require "equal treatment," but instead requires FERC to "balance the public interest in all of its stated dimensions, give equal consideration to conflicting interests, and reach a reasoned factual decision." California ex rel. State Water Res. Control Bd. v. Federal Energy Regulatory Comm'n, 966 F.2d 1541, 1550, 22 ELR 21397 (9th Cir. 1992).
137. Written testimony of Jeffrey Leahey, *supra* note 112, at 5. While it is true that FERC has introduced the Alternative Licensing Process and other streamlining efforts, it has had no effect on improving the length of the licensing process.
138. *See* Sensiba, *Who's in Charge Here?*, *supra* note 109, at 633 & n.194 (identifying an estimated 40 federal statutes that apply to hydropower licensing).
139. In 2015, Congress enacted the Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114-94, 129 Stat. 1312, which is intended to streamline federal permitting for major new infrastructure projects costing $200 million or more. While some of the principles of schedule setting, accountability, and transparency embodied in the FAST Act are needed in hydropower licensing, the Act itself is unlikely to significantly improve the FERC licensing process for hydropower. Much of the hydropower licensing need at FERC—particularly over the next 20 years—will be relicensing of existing, smaller facilities. Because the program is in its infancy, it is not clear whether it even applies to reauthorization of existing facilities, as the program is focused on new infrastructure development. Even if the program is sufficiently broad to capture hydropower relicensing generally, the vast majority of all relicensing work over the next 15 years—which, as explained above, involves primarily small hydropower—will not meet the FAST Act's $200 million threshold requirement. Finally, the FAST Act contains a sunset provision that occurs well prior to the average FERC licensing proceeding, creating significant uncertainty of the program's ability to support any hydropower licensing through conclusion.
140. 40 C.F.R. §1501.6 (2017).
141. *Id.* §1502.20.
142. *Id.* §1502.9.
143. 33 U.S.C. §1341(a)(3).
144. *See*, *e.g.*, Arizona Pub. Serv. Co., 94 FERC ¶ 61076, 61350 (2001):
> [A]n agency cannot intervene as a party in a [FERC] proceeding and at the same time be a cooperating agency for purposes of preparing an environmental analysis under [NEPA]. . . . To allow such a cooperating agency to intervene in a proceeding would put it in the position of having information that was not available to other parties, in violation of our rule prohibiting *ex parte* communications.
145. 18 C.F.R. §385.2201 (2017).

Together, the disjointed, sequential, and uncoordinated regulatory landscape causes significant delays, increased costs, and inconsistent agency directives, and stifles new hydropower project development and relicensing. For example:

- Although ESA regulations require formal consultation to conclude with a BiOp within 135 days,[146] the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS) routinely fail to meet this regulatory deadline—in some cases by an inordinate amount of time. For several pending hydropower licensings in the Southeast, BiOps on shortnose and Atlantic sturgeon have been delayed for many years. Despite urgings from the applicants and FERC, NMFS has yet to issue its BiOps and allow the licensing of these projects to proceed.
- At a hydropower project in California, a BiOp on green sturgeon has delayed for more than six years implementation of a groundbreaking comprehensive hydropower relicensing settlement—agreed to by more than 50 agencies and stakeholders, including FWS and NMFS—which would provide approximately $1 billion in numerous environmental, recreational, and other public benefits.
- Although CWA §401 imposes a one-year statutory deadline for states to make a decision on water quality certification, hydropower applicants are routinely pressured by the state to withdraw and refile their applications to reset the clock and give the state another year to act. Illustrating this issue, FERC noted in a 2014 order that of the 43 then-pending license applications for which FERC staff had completed environmental analysis, 29 (67%) were delayed due to state water quality certification. Thirteen of these projects are in California. Since that FERC order, FERC was finally able to move forward and issue licenses for some of these projects—but only for two California projects, which had been waiting for seven years for the state to issue a water quality certification.[147]
- For new project development on certain federal lands, a hydropower operator must obtain a special use permit under FLPMA. Often, the FLPMA permitting agency does not participate as a cooperating agency in FERC's preparation of the NEPA document, requiring the agency to undertake a separate NEPA analysis. Because this occurs after the FERC licensing, the sequential processing of the FLPMA permitting causes additional delays.
- The Corps rarely participates in the FERC licensing process for proposed hydropower projects at federal dams under its jurisdiction. Its absence often requires the developer to begin anew—after FERC issues the license—with the conduct of studies and environmental reviews, as the Corps completes its environmental review under NEPA and issues permits and authorizations under the CWA and Rivers and Harbors Act of 1899. The sequential nature of these permitting activities adds significant time, adds additional costs of repeating studies, adds uncertainty and increased risk that disfavors investment, and delays deployment of new hydropower resources. While FERC and the Corps in 2016 entered into an MOU in an effort to address some of these problems, it is unclear at the time of publication whether this MOU will result in any improvement.[148]

Congress and federal regulators have been grappling with these challenges for decades. In the Energy Act of 2000, for example, Congress directed FERC to investigate ways to reduce the cost and time of the hydropower licensing process.[149] Upon completing a comprehensive investigation of impediments in the licensing process—reviewing data as far back as the 1980s—FERC concluded that CWA water quality certification, as well as other factors, cause significant delay.[150] In response to Congress' direction to provide recommendations to address the delays, FERC (among other things) encouraged more centralized management of the approval process and better coordination among agencies involved.[151]

More recently, a FERC commissioner testified in Congress that continued delays in receiving the multiple federal and state agency approvals required before FERC can issue a license are significantly impeding the relicensing of existing facilities and suppressing new hydropower project proposals—in some cases for several years:

> It is a fact that the licensing process of hydropower projects (and the re-licensing of existing projects) is an expensive and multi-year process. However, most of the cost and time involved in this process can be traced to the requirements of the federal hydropower licensing law. This existing law

146. 16 U.S.C. §1536; FWS, Endangered Species, *Consultations Frequently Asked Questions—What Steps Are Involved in a Section 7 Consultation?*, https://www.fws.gov/Endangered/what-we-do/faq.html#2 (last updated Nov. 1, 2017).

147. PacifiCorp, 149 FERC ¶ 61038, at P 13 n.15 (2014).

148. Memorandum of Understanding Between United States Army Corps of Engineers and the Federal Energy Regulatory Commission on Non-Federal Hydropower Projects (2016), https://www.ferc.gov/legal/mou/2016/07-21-16.pdf.

149. Pub. L. No. 106-469, §603, 114 Stat. 2029, 2041.

150. *See* 603 Report, *supra* note 110, at 16-17 (noting that "the section 401 certification process is often very time-consuming, despite the intent of the CWA that a State should act on a certification request in a year or less"); Hydropower Vision, *supra* note 7, at 143:

> The median time from the filing [of] a license application to its conclusion for recent applications is 43 months. Many proceedings, however, take substantially longer. Many specific factors contribute to delays, but the underlying source of most delays is a statutory scheme that disperses decision making among federal and state agencies acting independently of [FERC]'s proceedings. The most common cause of long delayed proceedings is untimely receipt of state water quality certification under the [CWA].

(Citation omitted.)

151. *See* 603 Report, *supra* note 110, at 88-89.

> emphasizes both extensive environmental reviews of a project's impacts and a role for federal and state resource agencies. There are no consequences to these agencies if they miss deadlines that are part of [FERC]'s licensing process or of the laws and regulations they must comply with before [FERC] can issue a license, such as the [ESA] and the [CWA]. For those members interested in promoting hydropower development, an examination of this and related laws and specifically the roles and responsibilities of resource agencies could help streamline the licensing process and allow greater certainty for those seeking to develop this abundant renewable resource.[152]

Echoing these concerns and potential solutions, the *Hydropower Vision* report finds:

> Costs, risks, and implementation timeframes may be reduced by providing stakeholders with an increased knowledge base, easier access to information relevant to their projects, and increased capabilities for collaboration. Achieving the same or improved outcomes more quickly and predictably will reduce the risks and costs to developers and encourage investment in new projects by the financial community, without a reduction in environmental protection.[153]

While the problems in hydropower authorization are well-documented, consensus solutions have been fleeting. While industry advocates generally prefer solutions aimed at eliminating redundant studies and actions, reducing time frames for agency decisionmaking, and establishing clear deadlines for action, the environmental community and resource agencies tend to favor robust study over schedule and take the position that imposing absolute deadlines on agencies would be tantamount to stripping resource agencies of their statutory responsibilities to protect and manage environmental resources.

Balancing these two viewpoints, the following solutions would provide meaningful improvements to the process, reduce time and expenses to hydropower developers, and protect agencies' statutory responsibilities:

- Congress should reform the hydropower licensing and permitting program by statutorily designating FERC as the lead agency, for purposes of NEPA review, for all licenses and permits required under federal law.[154]
- To address state-law requirements requiring the state to conduct any required environmental review in conjunction with state action authorized under federal law, Congress should provide for states to participate as a cooperating agency with FERC, while providing opportunity for states to complete additional reviews under state law that are beyond the scope of NEPA.
- To prevent ex parte communications between decisional staff within FERC and cooperating agencies, Congress should direct all cooperating agencies to promulgate regulations that separate cooperating and decisional staff in the hydropower process. All agencies that designate decisional, separated staff should not be precluded from intervening in the FERC licensing process.[155]
- To help reduce redundancy in environmental studies and ensure sufficient time to complete all needed studies, Congress should direct FERC and all other resource agencies to develop a single comprehensive study plan at the beginning of the federal approval process, which will inform agency decisionmaking under all licensing and permitting requirements under federal law.[156]
- To help ensure that agencies have needed resources to fulfill their responsibilities under federal law, Congress should provide mechanisms for agencies to receive direct funding from hydropower license applicants, such as through collection agreements or an amendment to FPA §17 that would provide for their administrative costs associated with hydropower licensing to be remitted directly to the agencies, without further appropriations.[157]
- To help promote timely participation by the hydropower applicant and participating resource agencies, Congress should empower FERC to establish a centralized schedule for the completion of all licenses and permits required for a nonfederal hydropower project. When establishing the schedule, FERC should be required to collaborate with resource agencies and the applicant, to be sure that the schedule is reasonable and provides sufficient opportunity for

152. *Hearing Before the House Comm. on Energy and Commerce*, *Subcomm. on Oversight and Investigations*, 112th Cong. 5-6 (2011) (testimony of Philip D. Moeller, Commissioner, FERC), https://www.ferc.gov/EventCalendar/Files/20110707120333-Commissioner%20Moeller's%20Testimony.pdf.

153. Hydropower Vision, *supra* note 7, at 380.

154. This is a provision under consideration in both the House and Senate in the 115th Congress. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §3(a) (2017). It also is consistent with reforms to the gas pipeline certification program under the Natural Gas Act pursuant to EPAct 2005. 15 U.S.C. §717n; Regulations Implementing the Energy Policy Act of 2005; Coordinating the Processing of Federal Authorizations for Applications Under Sections 3 and 7 of the Natural Gas Act and Maintaining a Complete Consolidated Record, 71 Fed. Reg. 62912 (Oct. 27, 2006).

155. A similar provision is under consideration in the Senate in the 115th Congress. *See* S. 1460, 115th Cong. §3001(c) (2017).

156. A similar provision is under consideration in the House in the 115th Congress. *See* H.R. 3043, 115th Cong. §3(a) (2017). Both the Senate and House are considering measures to improve environmental study requirements in hydropower licensing. *See id.*; S. 1460, 115th Cong. §3001(c) (2017).

157. 16 U.S.C. §810. However, safeguards would need to be put in place to ensure that agency costs are reliable and actually incurred in the administration of responsibilities for nonfederal hydropower, in light of long-standing litigation uncovering significant problems in agency recordkeeping and accounting practices. Both the House and Senate are considering measures that would allow agencies to receive direct funding from hydropower licensing applicants. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §3(a) (2017).

all participants to complete their responsibilities in a timely manner.[158]

- To ensure that all participants meet the deadlines set forth in the centralized schedule, Congress should include appropriate enforcement mechanisms. As noted above, this has been an area of considerable disagreement among various policymakers and stakeholders; while most understand the need to include incentives to keep the process moving forward, some are strongly opposed to imposing deadlines that would, by missing the deadline, result in the loss of agency authority. Agencies also need to have sufficient scientific information completed prior to fulfilling their statutory obligations.

To address these issues, Congress has a range of options based on past experience:

- *Absolute deadlines*: Similar to the reforms in the Fixing America's Surface Transportation (FAST) Act, Congress should enact a comprehensive restructuring of the hydropower approvals process—in which hydropower applicants provide direct funding to resource agencies, FERC, and other agencies to develop a single, comprehensive study plan at the very beginning of the process, and agencies work with FERC in establishing reasonable deadlines for action. This seems to resolve agencies' current challenges with timely action, justifies an expectation that they will act in a timely manner, and ensures that they have all needed information to render a decision.[159] Mandating these safeguards, in turn, seems to warrant requiring accountability by setting statutory imposed deadlines, such as those that already apply to state water quality certification under CWA §401 and state consistency determination under the CZMA.[160]
- *Budgetary penalties*: Similar to its approach for ensuring timely action by the Corps under the Water Resources Reform and Development Act of 2014, Congress could impose budgetary penalties against agencies that fail to meet deadlines established in the centralized schedule.[161]
- *Publication, dispute resolution, and reporting*: Consistent with the regulatory process improvements in the FAST Act, Congress could encourage timely agency decisions through publication of agency status reports under the federal permitting dashboard, periodic reporting to Congress and agency heads, and dispute resolution.[162]
- *Judicial review*: Consistent with its approach in EPAct 2005 in the context of natural gas pipeline certification, Congress could extend jurisdiction to the U.S. courts of appeals over "[t]he failure of an agency to take action on a permit required under Federal law,"[163] and direct the court to "set a reasonable schedule and deadline for the agency to act on remand."[164]

D. *Promote Upgrades and Optimization of Existing Hydropower Projects Through Streamlined FERC Amendment Procedures and Jurisdictional Changes at Federal Dams*

As noted in Part II above, there is immense potential to increase hydropower generation in the United States simply through upgrading equipment at existing hydropower facilities, expanding installed capacity at such facilities, and optimizing operation of existing facilities through modern technologies. DOE estimates that by 2030, up to 9.4 GW of new hydropower generation could be added through these efforts,[165] with the addition of up to another 13 GW by 2050[166]—enough to power more than seven million homes and avoid almost 54 million metric tons of CO_2 emissions annually.[167]

To realize this potential, however, several regulatory challenges must be resolved. At FERC-licensed projects, expansion and many modernization and efficiency improvements require FERC to amend the license.[168] FERC's regulations governing license amendments impose a time-consuming and burdensome "three-stage consultation" process for any amendment proposing to increase

158. This is a provision under consideration in both the House and Senate in the 115th Congress. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §3(a) (2017).

159. Both the House and Senate are considering measures that would allow agencies to receive direct funding from hydropower licensing applicants, establish FERC as the lead agency, and require FERC to work with resource agencies to develop a centralized schedule for all federal authorizations. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §3(a) (2017). The House is also considering a measure that would require FERC and other resource agencies to engage in early consultation, issue identification, and dispute resolution. *See* H.R. 3043, 115th Cong. §3(a) (2017).

160. CWA §401(a)(1), 33 U.S.C. §1341(a)(1) (one-year deadline); CZMA §307, 16 U.S.C. §1456(c)(3) (six-month deadline). Similar to the FAST Act, neither the House nor Senate bills under consideration in the 115th Congress contain an absolute waiver of statutory authority in the event of agency delay. The Senate is considering a provision that would refer the matter to the Office of Management and Budget, in consultation with the Council on Environmental Quality. *See* S. 1460, 115th Cong. §3001(c) (2017). The House is considering a provision that would allow FERC to grant limited extensions of time in the schedule, but the current version of the bill, which has cleared the House Committee on Energy and Commerce, contains no affirmative schedule enforcement mechanism. *See* H.R. 3043, 115th Cong. §3(a) (2017).

161. Water Resources Reform and Development Act of 2014, Pub. L. No. 113-121, §1005, 128 Stat. 1193, 1207-08. While Congress could reduce funding to federal agencies that miss deadlines, there would be additional challenges in withholding federal funding from state agencies that fail to comply.

162. *See generally* 42 U.S.C. §4370m-2.

163. 15 U.S.C. §717r(d)(2).

164. *Id.* §717r(d)(3).

165. Hydropower Vision, *supra* note 7, at 4.

166. *Id.* at 7, 31.

167. *See supra* note 21.

168. *See* 16 U.S.C. §803(b) (prohibiting, except in emergency situations, any "substantial alteration or addition not in conformity with the approved plans . . . without the prior approval of [FERC]"); *id.* §799 (providing that licenses "may be altered or surrendered only upon mutual agreement between the licensee and [FERC]").

a project's installed capacity by 2 MW or more and the hydraulic capacity by at least 15%[169]—which is essentially the same burdensome process that governs new project development or relicensing at the end of a 30- to 50-year license term. Thus, even modest proposals to expand capacity can lead to excessive costs, time delays, and tremendous risk and uncertainties associated with resource agencies' authority to impose mandatory conditions that have nothing to do with the proposed project expansion.

Moreover, FERC's policies and statutory constraints under the FPA itself often do not allow the licensee sufficient time to recoup the significant investment that frequently accompanies project expansion activities. For larger hydropower projects, modernization and efficiency improvements often cost hundreds of millions of dollars, and yet FERC is required under the FPA to limit license terms to 50 years.[170] Thus, a project that is operating under a 40-year license (the default license term under FERC's policy) can only qualify for a 10-year extension for these types of additional investments made during the license term.[171] Given these risks, expenses, and constraints, licensees of nonfederal hydropower have little regulatory incentive to explore opportunities to expand their projects or seek operational changes that could optimize performance.

Other challenges face upgrades and optimization at federal hydropower facilities. At a time of reduced agency budgets, limited appropriations render these expensive activities infeasible. And while a tremendous proportion of the potential to expand hydropower through improvements and upgrades exists at federal hydropower facilities, federal policies simply do not incentivize expansion of hydropower.[172] Although private development is possible at some of these facilities, in many cases, congressional authorization reserved federal authority to develop the hydropower resources, thus precluding FERC's licensing jurisdiction for nonfederal development.[173] Even where FERC does have licensing jurisdiction for nonfederal development at a federal dam, the Corps often opposes the project proposal and FERC responds by rejecting the proposal.[174]

These policies have significantly hindered most efforts to upgrade existing hydropower projects, taking advantage of infrastructure already in place, to develop additional renewable, non-emitting electric power generation. Of the more than 1,030 hydropower projects currently under a FERC license, relatively few have completed major upgrades, and they accounted for very little new capacity. Although DOE, DOI, and the U.S. Department of the Army entered into an MOU in 2010 for the express purpose of advancing hydropower on federal lands and at federal dams,[175] efforts under this MOU have resulted only in the addition of 33 MW at 10 Bureau of Reclamation hydropower facilities and 19.4 MW at three Corps dams.[176]

The following solutions are available to address these significant impediments to realizing the benefits of capturing additional hydropower at existing hydropower facilities:

- Congress should reform FERC's license amendment process by implementing a fast-track procedure for efficiency upgrades, modernization activities, and upgrades that are not anticipated to produce significant environmental effects. Recognizing the benefits of expanding hydropower at existing infrastructure, Congress should also require agencies' conditioning authority to be focused only on environmental effects of the upgrades.[177]
- Congress should authorize FERC, when approving a project upgrade or efficiency improvement, to extend license terms beyond 50 years to allow the project owner sufficient time to recoup the cost of investment.[178] Alternatively, Congress could direct FERC to consider the significant investment of project upgrades and improvements when it establishes the new license term during the project's next relicensing.[179]
- Congress should consider opportunities to use private capital to upgrade and expand federal hydropower facilities, including the possibility of shifting jurisdiction to FERC to issue licenses for nonfederal hydropower development at sites that currently are reserved for federal development.

E. Focus Licensing Requirements for New Pumped Storage Projects, Particularly Closed-Loop Systems

As explained in Part I above, both the DDPP and DOE reports point to a significant expansion of pumped stor-

169. 18 C.F.R. §§4.38, 4.201(b) (2017).
170. 16 U.S.C. §799.
171. FERC's policy statement on establishing license terms also provides that it will consider substantial investments made under the prior license, excluding maintenance or other measures required by that license or other legal authority, in determining a new license term. Policy Statement on Establishing License Terms for Hydroelectric Projects, 82 Fed. Reg. 49501, 49503 (Oct. 26, 2017).
172. *See supra* Part III.A.
173. *See generally* Uncompahgre Valley Water Users Ass'n v. Federal Energy Regulatory Comm'n, 785 F.2d 269 (10th Cir. 1986). FERC and the Bureau of Reclamation, and FERC and the Corps, have MOUs in place to decide jurisdictional questions at federal dams. *See supra* notes 64, 67, and 148.
174. Rivertec Partners LLC, 156 FERC ¶ 62161 (2016); Advanced Hydropower, Inc., 155 FERC ¶ 61007 (2016); Symphony Hydro LLC, 150 FERC ¶ 62092 (2015).
175. Energy, Interior & Army MOU, *supra* note 67.
176. Memorandum of Understanding for Hydropower Among the Department of Energy, the Department of the Interior, and the Department of the Army (Five-Year Extension) (2015), https://energy.gov/sites/prod/files/2015/03/f20/Memorandum-of-Understanding-for-Hydropower-Five-Year-Extension.pdf.
177. This is a provision under consideration in both the House and Senate in the 115th Congress, although only the House bill seeks to limit agency conditioning authority. *See* S. 1460, 115th Cong. (2017); H.R. 3043, 115th Cong. (2017).
178. This was a provision of Rep. Cathy McMorris-Rodgers' (R-Wash.) draft hydropower bill released in 2015 during House Energy and Commerce Committee deliberations.
179. This is a provision under consideration in both the House and Senate in the 115th Congress. *See* S. 1460, 115th Cong. §3001(c) (2017); H.R. 3043, 115th Cong. §2(e) (2017).

age resources in the United States as essential to decreasing our reliance on traditional, fossil fuel electricity-generation sources and transitioning to renewable sources of electricity.[180] Especially in light of the proliferation of non-dispatchable renewables such as solar and wind, pumped storage will be needed to balance the electric system and integrate these resources to the grid.[181]

Currently, the same FERC licensing process and standards that pertain to conventional hydropower apply to pumped storage projects. Even though pumped storage projects serve a far more focused role of energy storage, grid security, and transmission support, the multiple public interests of the FPA (e.g., environmental enhancements, public recreation, water supply, irrigation, and other considerations[182]) apply to the licensing of these projects. Although pumped storage projects typically feature at least one artificial water body as the upper reservoir and by their very nature involve significant fluctuations in water levels to respond to grid needs, FPA licensing standards typically require these projects, just like conventional projects, to promote public recreation and environmental enhancements.[183]

This can result in higher up-front capital costs and negatively affect project operations and long-term project economic viability—adding to what already is a tremendously challenging economic climate for developers of pumped storage.[184] These added burdens on pumped storage projects, together with the same delays, inefficiencies, and other impediments facing conventional hydropower discussed in Part II above, have created a climate that discourages and disincentivizes expansion of pumped storage—even though the DDPP and DOE reports both indicated the need and opportunity for these projects in the future to support a growing demand for renewables.

As a general matter, the legal reform solutions offered in this section would reduce impediments to both conventional and pumped storage hydropower development. The unique and focused purpose for pumped storage projects, however, offers additional solutions for Congress and policymakers to consider:

- Congress could define new licensing parameters that apply only to pumped storage projects, or even just closed-loop systems. For example, in some parts of the United States, particularly the West, the FPA licensing requirements are often triggered only because a project's "primary" transmission line traverses federal lands.[185] FERC maintains, further, that a closed-loop pumped storage project using only groundwater is subject to mandatory licensing jurisdiction if it is partially located on federal lands, even though groundwater does not qualify as a "stream" under FPA §23(b).[186] To limit the licensing burdens on pumped storage—and to rely instead on traditional environmental permitting requirements—Congress could decide to redefine the extent to which FPA mandatory licensing should apply to pumped storage.[187]
- Congress could create a more-efficient specialized licensing process for some categories of pumped storage, particularly closed-loop systems—recognizing that these projects serve a specialized purpose in which the full array of public benefits under the FPA do not fit, and that these projects tend to have less impact (if any) on surface water resources. The streamlined process could reduce the regulatory time frame, as well as the environmental scope of review and agency conditioning authority—again recognizing that while environmental effects should be avoided or mitigated, other enhancement activities should not apply to this more specialized infrastructure.[188]
- In the 14 western states in which the Bureau of Reclamation administers federal projects, pumped storage development often involves the use of at least one federal impoundment administered by the Bureau of Reclamation. These development opportunities raise the question of whether these projects require licensing by FERC, an LOPP from the Bureau of Reclamation, or both. Congress could reduce the uncertainty of developments at Bureau of Reclamation facilities by clarifying jurisdictional limits and reducing overlapping responsibilities between FERC and the Bureau of Reclamation at these sites.[189]

F. *Facilitate Development of Hydropower at Existing Non-Powered Dams Without Interfering With Existing Use of the Dams*

As explained in Part II above, much of the development potential for new hydropower in the United States is at existing dams that currently are not equipped with hydropower-generating facilities. A 2012 DOE assessment of existing non-powered dams concluded that, of the more than 80,000 existing dams in the United States, more than 50,000—nearly two-thirds of all non-powered dams—

180. *See supra* Part I.
181. *Id.*
182. *See* 16 U.S.C. §§797(e), 803(a)(1).
183. *See, e.g.*, Exelon Generation Co., 153 FERC ¶ 62232 (2015) (order issuing new license to pumped storage project with recreation facilities, including a campground, park, and wildlife management area); New York Power Auth., 41 F.P.C. 712 (1969) (order issuing new license to pumped storage project with recreation facilities, including a visitors center, overlook, and fishing access site).
184. *See infra* Part IV.
185. A "primary" transmission line is a line used solely to transmit power from a licensed project to a load center, and without the line there would be no way to transmit all the project power to market. *See* Pacific Gas & Elec. Co., 85 FERC ¶ 61411, 62559 (1998).
186. Mike Swiger et al., *Pumped Storage: 5 Misperceptions About Licensing*, Int'l Water Power & Dam Construction, June 2017, at 14, *available at* http://www.vnf.com/webfiles/Pumped%20storage.pdf.
187. Reducing the scope of FERC's mandatory licensing jurisdiction over these projects need not preclude FERC from issuing a voluntary license under FPA §4(e). In some cases, a developer might decide the regulatory burdens of a FERC license are preferable to state regulation. *See id.*
188. S. 1460, 115th Cong. §3003 (2017); H.R. 2880, 115th Cong. (2017); H.R. 8, 114th Cong. §1204 (2015).
189. S. 1460, 115th Cong. §3007 (2017); H.R. 1967, 115th Cong. (2017).

are suitable for hydropower development.[190] DOE's more recent *Hydropower Vision* report finds the potential for adding 12 GW of hydropower at existing non-powered dams by 2050.[191]

Despite this significant potential to avoid millions of metric tons of CO_2 emissions each year by capitalizing on existing infrastructure, current regulatory requirements—many unique to nonfederally owned dams—are a significant impediment to this opportunity. While FERC licensing of nonfederal hydropower at federal dams expressly cannot interfere with ongoing federal operations at the dam,[192] the same is not true of new projects at existing nonfederal dams. At nonfederal dams, owners of an existing facility that is used for municipal water supply, irrigation, recreation, navigation, or other public purposes face a distinct risk that FERC's licensing decisions, which are statutorily required to balance a number of public uses in the public interest,[193] will result in changes to reservoir operations that could significantly interfere with the very purpose for which the dam and reservoir were constructed in the first place.[194] In addition to FERC, other federal and state resource agencies have the opportunity to further condition dam operations to address issues such as fish passage, aquatic resources, and water quality.[195] Such changes could include, for example, minimum flow requirements for aquatic resources that are different from the dam's current release schedule for downstream municipal water supply.

Because the dam, reservoir, and shoreline areas are all statutorily included as part of the FERC-licensed project,[196] moreover, FERC regulations require the project developer to obtain fee simple property ownership or interest in perpetuity to occupy these lands for purposes of the project,[197] and the FPA extends a federal right of eminent domain for the licensee to obtain these lands.[198] FERC's policies and regulations require these lands and waters to be maximized for public recreation,[199] and shoreline development and use are governed under FERC-approved shoreline management plans that govern and restrict private development.[200] These requirements could significantly change development and management regulations and standards of shoreline areas of the existing reservoir—such as reservoir level requirements, dock permitting limits, and affirmative FERC approval of marinas, boathouses, and other infrastructure.

The comprehensive licensing scheme under the FPA simply does not work for new hydropower development at existing non-powered dams. Because these dams and reservoirs already operate to meet a specific purpose (e.g., municipal water supply), the prospect of applying the full range of environmental, land use, recreational, and other requirements only causes owners of these facilities to oppose potential hydropower development. Although these dam owners could potentially benefit from an added revenue stream created by new hydropower development, the risk of losing the ability to manage the dam and reservoir for their original and primary purposes tends to be a far stronger concern. Over the past decade, only 33.1 MW of installed capacity has been installed at existing nonfederal dams, enough to power 10,462 homes and avoid 79,496 metric tons of CO_2 emissions annually.[201]

Unless regulatory changes are implemented that recognize and protect the primary purposes of existing dams and reservoirs, the potential of these sites will not be recognized. Releases from these reservoirs will continue for the purposes for which they were originally constructed, but without the added benefit of non-emitting electric power generation, and without modest improvements to environmental management that could be accomplished through appropriate regulation.

Solutions to help promote the development of new hydropower facilities at existing, non-powered dams include[202]:

- Rather than requiring hydropower development to be licensed, Congress should create a new "exemption" program for the purpose of authorizing new hydropower development at non-powered dams, similar to the exemption programs already available under FPA §33 and the Public Utility Regulatory Policies Act of 1978.[203] While a FERC-issued exemption would bring the project under federal regulation, it would do so in a manner that respects the existing use of the dam and reservoir. Because a FERC-issued exemption does not carry the federal right of eminent domain, the existing owner of the dam and reservoir would be protected by ensuring landowner consent for development of hydropower resources at the site.

190. Assessment of Energy Potential at Non-Powered Dams, *supra* note 17, at vii.
191. Hydropower Vision, *supra* note 7, at 95, 251.
192. *See* Alabama Power Co., 157 FERC ¶ 62218, at P 22 (2016); Seneca Generation, LLC, 152 FERC ¶ 62045, at P 26, *reh'g denied*, 153 FERC ¶ 61234 (2015); City of Broken Bow, 140 FERC ¶ 62237, at P 33 (2012).
193. *See* 16 U.S.C. §§797(e), 803(a)(1).
194. East Tex. Elec. Coop., Inc., 136 FERC ¶ 62171, at P 66-68 (2011), *order on reh'g & clarification*, 140 FERC ¶ 61228 (2012).
195. *See* 16 U.S.C. §§811, 1536; 33 U.S.C. §1341.
196. 16 U.S.C. §796(11).
197. 18 C.F.R. §2.7(a) (2017); Form L-5, Terms and Conditions of License for Constructed Major Project Affecting Navigable Waters and Lands of the United States, 54 F.P.C. 1832, 1834 (1975) (Standard Article 5).
198. 16 U.S.C. §814.
199. 18 C.F.R. §2.7 (2017). *But see* City of Rockingham v. Federal Energy Regulatory Comm'n, 702 Fed. Appx. 106 (4th Cir. 2017), *cert. denied*, No. 17-526, 2018 WL 942441 (2018) (unpublished opinion) (adopting FERC's interpretation of its recreation policy that it must require recreational resources that are "reasonable in light of the facts present in the case" and not "the best [recreation] at any cost"), *petition for cert. filed*, No. 17-526 (Oct. 10, 2017).
200. *See generally* Office of Energy Projects, FERC, Guidance for Shoreline Management Planning at Hydropower Projects (2012), *available at* https://www.ferc.gov/industries/hydropower/gen-info/guidelines/smpbook.pdf.
201. *See supra* note 21. By far, the largest of these projects is the Lake Livingston Project in Texas, which alone is 24,000 kilowatts and represents nearly 75% of all new capacity at non-powered dams constructed over the past decade.
202. During the 115th Congress, a bill has been introduced in the House that includes these proposed solutions. *See* H.R. 2872, 115th Cong. (2017).
203. 16 U.S.C. §§823a-3, 823d.

- To ensure that hydropower operations remain compatible with the existing uses of the dam and reservoir, Congress should limit the conditioning authority of FERC and other agencies to preclude conditions that would materially modify existing water release schedules. FERC and resource agencies should be empowered to impose operating conditions that address environmental effects of developing and operating the hydropower facility.
- Consistent with FERC's approach in licensing non-federal hydropower at federal dams, Congress should direct that the exempted project includes only the hydropower facility and any associated transmission lines. Such an approach would avoid intrusive regulation of recreation facilities, reservoir operations, and shoreline lands that are unnecessary to ensure the production of new hydropower at the site.

G. Prioritize Research and Development for MHK Technologies and Implement a Smarter Permitting Scheme

Despite the enormous potential of MHK technologies to increase hydropower's contribution to overall decarbonization, their development for commercial-scale applications continues to face numerous challenges. Chief among those challenges is the high cost of developing and deploying MHK technologies, which must be built to withstand the harsh conditions of marine and in-river environments. As a result, there are significant challenges to siting MHK projects, particularly where there is a lack of transmission and, for offshore locations, competing ocean uses, which can spur local opposition. In addition, in many cases, the potential effects of an MHK project on the environmental resources of the areas where the MHK resource is most available are not well-known.

Given these substantial hurdles, commercial deployment of MHK technologies has been cost-prohibitive to date, and significant investment in the market is needed. Although DOE's Water Power Program has provided some stimulation in recent years to the deployment of MHK technology as described in Part II above, the industry remains hindered by a lack of funding for its research and development. DOE's Water Power Technologies Office remains one of the smallest programs within DOE's Office of Energy Efficiency and Renewable Energy. While funding has increased steadily over the past decade with few exceptions, the Water Power Program—which funds both hydropower and MHK resources—received just $70 million for FY 2016.[204] This was the lowest amount of funding provided to all renewables, including for far more established resources like wind and solar, which for FY 2016 received nearly $100 million and nearly $250 million, respectively.[205]

Substantial and sustained investment is necessary to accelerate the MHK technology market, as it has stimulated the development of other renewable energy sources like wind and solar. Prioritizing MHK funding will aid in research and development efforts and ultimately lower costs for MHK technology development—the only way to tap into the vast potential of the MHK resource in aiding hydropower's contribution to decarbonization.

The difficulties in permitting MHK projects have also posed a hurdle to its development. Although FERC implemented a number of initiatives to promote and streamline the testing and authorization of MHK projects, those initiatives, on their own, have been insufficient to jump-start MHK development. The process for approving even pilot projects has proved just as lengthy and difficult as for conventional hydropower projects. Accordingly, vast improvements to the regulatory process are required to streamline the approvals needed to overcome impediments to MHK development. Meaningful changes to the hydropower licensing process, including all of the legal reforms described in Part III.C. above, would equally benefit the MHK industry. Implementation of an expeditious permitting scheme is crucial to securing the funding necessary for MHK technology deployment at the commercial scale.

IV. Resolving Market Impediments to Hydropower Development

Improving the arcane federal licensing process for hydropower is a necessary, but not sufficient, condition to maintaining and expanding the country's hydropower resources. Both existing and new hydro must compete with other electric power-generating sources in today's partially deregulated electricity markets. Although hydropower has an advantage over some fuel sources in that its fuel—water—is free and replenishing, conventional and pumped storage hydropower require significant investments of capital upfront and long lead times for permitting and construction. Low prices for natural gas and oil, as well as lower costs for other renewables such as wind and solar, drive down the market price of electricity, making new hydropower less attractive for investors and threatening to strand investments in existing hydropower plants.

Tax incentives are one way to make new hydropower development more attractive for investors; but to date, federal tax incentives have been limited and appear to be phasing out for the foreseeable future. A federal or state carbon tax would also make hydropower more competitive with fossil fuel electric power-generating sources, and could be a long-term solution to providing the right incentives to

204. *See* DOE Office of Energy Efficiency and Renewable Energy, *Water Power Program Budget*, https://energy.gov/eere/water/water-power-program-budget (last visited Dec. 11, 2017).

205. Kelsi Bracmort, Congressional Research Service, DOE's Office of Energy Efficiency and Renewable Energy (EERE): Appropriations Status CRS-8 (2017), *available at* https://fas.org/sgp/crs/misc/R44262.pdf.

develop more emissions-free hydropower.[206] For the more immediate future, however, electricity market reforms at the federal and state levels that properly compensate hydropower for its benefits to the electric system could be the key to ensuring hydropower's continued economic viability.

As discussed earlier in this Article, hydropower provides not only reliable generation, but key grid support services to the electrical bulk power system.[207] These ancillary services and essential reliability services include peaking power,[208] frequency control,[209] reserve generation,[210] load following and balancing,[211] and black-start capabilities.[212] In addition, hydropower projects with water storage capability, in particular pumped storage hydropower projects, support integration into the grid of variable generation sources such as wind and solar because hydropower can supply energy when these intermittent sources of generation are not available.[213] Prior to the advent of deregulated wholesale electricity markets, vertically integrated utilities could recover the cost of providing these services through electric rates.

FERC's landmark Order No. 888 in 1996 required open-access transmission tariffs to remove impediments to competition in the wholesale bulk power markets.[214] Since then, FERC has encouraged and regulated the development of regional transmission organizations (RTOs) and independent system operators (ISOs), which control the dispatch of generation sources and electric transmission systems. In general, FERC's policy has been to accept as just and reasonable single clearing price auctions for energy and capacity in the organized markets that favor least cost, dispatchable resources, without regard to fuel source.[215]

However, encouraging competitive markets in wholesale power can disfavor generation sources, such as hydropower, that provide system benefits to the grid that are not compensated by RTO/ISO pricing mechanisms. DOE in its *Hydropower Vision* report captures the problem thusly:

> The full accounting, optimization, and compensation for hydropower generation, grid ancillary services and essential grid reliability services in power markets is difficult, and not all benefits and services provided by hydropower facilities are readily quantifiable or financially compensated in today's market framework. In both traditional and restructured market environments, many hydropower services and contributions are not explicitly monetized, and, in some cases, market rules undervalue operational flexibility.[216]

Or, as a former administrator of the Bonneville Power Administration summarized it: "Market rules generally undervalue operational flexibility, which is a prime attribute of hydropower. Because the services are not appropriately compensated, these valuable attributes are not optimized and potentially wasted."[217]

Storage technologies, including pumped storage hydropower, are particularly needed to balance the increasing deployment levels of intermittent renewable energy sources such as wind and solar power. Former DOE Secretary Steven Chu put it succinctly in characterizing hydropower pumped storage as "astoundingly efficient. . . . In this future world where we want renewables to get to 20%, 30%, or 50% of our electricity generation, you need pumped hydro storage. It's an incredible opportunity and it's actually the lower cost clean energy option."[218] A 2014 Argonne National Laboratory study concluded that "providing further support for the development of new [pumped storage hydropower] units and [adjustable speed] upgrades to existing [pumped storage hydropower] units will contribute to grid reliability and will facilitate a larger expansion of variable renewable energy, thereby reducing power system emissions in the United States."[219]

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206. Chi-Jen Yang & Robert B. Jackson, *Opportunities and Barriers to Pumped-Hydro Energy Storage in the United States*, 15 Renewable & Sustainable Energy Revs. 839, 843 (2011). Although a federal carbon tax seems unlikely in the foreseeable future given the current makeup of the Administration and Congress, some states are currently debating the issue. *See* Clearing Up No. 1793 (Energy NewsData, Seattle, Wash.), Mar. 31, 2017, at 9 (reporting on Washington H.B. 1646).
207. *See* Hydropower Vision, *supra* note 7, at 96-111.
208. "Peaking power" refers to generating plants that can be brought online quickly to meet high, or peaking, demand. *Id*. at 81, 99.
209. Alternating current is transmitted from the power generating source to the end-user at a standard frequency, 60 hertz, in the United States. "Frequency control" refers to the maintenance of frequency within a normal band and control time error and is attained through adjustment of the mechanical power of the generators using speed governor feedback and area generation control. *See id*. at 101.
210. "Spinning reserve" refers to available capacity in the system that can be brought online to avert a system collapse when system load and generation are significantly imbalanced, such as when a generating unit or interconnection to a neighboring system fails. *See id*.
211. "Load-following" refers to a power plant that can quickly adjust its power output as demand for electricity fluctuates throughout the day. "Load balancing" refers to the process and measures for controlling system generation to match the prevailing load throughout the daily and weekly cycle of demand in the electrical distribution system. *Id*.
212. "Black start" refers to the capability of a generating station to begin operation independently, without reliance on external energy sources, and to power up other generating stations on the associated interconnected grid in the event of a blackout. *Id*.
213. *Id*. at 103.
214. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, FERC Order No. 888, 61 Fed. Reg. 21540 (May 10, 1996), F.E.R.C. Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31036 (1996), *order on reh'g*, FERC Order No. 888-A, 62 Fed. Reg. 12274 (Mar. 14, 1996), F.E.R.C. Stats. & Regs. [Regs. Preambles] ¶ 31048, *order on reh'g*, FERC Order No. 888-B, 81 FERC ¶ 61248 (1997), *order on reh'g*, FERC Order No. 888-C, 82 FERC ¶ 61046 (1998), *aff'd in relevant part sub nom*. Transmission Access Policy Study Group v. Federal Energy Regulatory Comm'n, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom*. New York v. Federal Energy Regulatory Comm'n, 535 U.S. 1 (2002).
215. Southwest Power Pool, Inc., 112 FERC ¶ 61303, at P 23 (2005); Midwest Indep. Transmission Sys. Operator, Inc., 102 FERC ¶ 61196, at P 32 (2003).
216. Hydropower Vision, *supra* note 7, at 50-51.
217. *Hearing on "Powering America: Valuing Reliability in a Transforming Electricity Industry" Before the House Comm. on Energy and Commerce, Subcomm. on Energy*, 115th Cong. 2 (2017) (written testimony of Steve Wright, General Manager, Chelan County Public Utility District No. 1, on behalf of the National Hydropower Association), http://docs.house.gov/meetings/IF/IF03/20171003/106457/HHRG-115-IF03-Wstate-WrightS-20171003-U3.pdf.
218. Pumped Storage Development Council, *supra* note 86, at 3 (quoting Secretary Chu).
219. Decision and Information Sciences Division, Argonne National Laboratory, Pumped Storage Hydropower: Benefits for

Yet, while pumped storage accounts for almost all existing electricity storage in the United States, only one small pumped storage facility (Olivenhain-Hodges in California) has been built since 1995.[220] As a 2013 DOE report explained, there are significant market barriers to new pumped storage facilities due to a lack of adequate revenue streams to support their development:

> Restructured markets base pricing on the generation costs of the marginal unit, which is appropriate for generators that have significant operating costs but creates a difficult situation for capital intensive and low operating cost resources like energy storage. Deployment of energy storage resources can collapse ancillary service market prices and energy market price differences, resulting in revenue streams for storage that are not commensurate with the value these resources provide to the system. Other market issues that present barriers include: the lack of markets and associated products [grid services]; and the lack of transparent price signals for most products in non-ISO/RTO markets and for cost-based products in ISO/RTO markets.[221]

Pumped storage hydropower, like electricity storage generally, "sits in the gray area between generation and transmission."[222] Congress has recognized that pumped storage can reduce the need for transmission upgrades. EPAct 2005 directed FERC to "encourage, as appropriate, the deployment of advanced transmission technologies," which are defined to include "energy storage devices" including pumped storage.[223] Yet, FERC in 2008, while finding that the proposed Lake Elsinore Advanced Pumped Storage (LEAPS) project in California qualified as "advanced transmission technology" and could displace the need for new transmission, denied the developers' request for the project to be categorized as a transmission facility for purposes of rate recovery. FERC was concerned that power bid into the system from the facility, which would be under the operational control of the California Independent System Operator, Inc. (CAISO), could receive preferential treatment, thus undermining competitive pricing.[224] In addition, the CAISO actively opposed the project.

Pumped storage hydropower projects use more energy than they generate. The economic value of pumped storage used to be the arbitrage between the relatively low cost of pumping power at night (due to reduced demand and surplus generation on the system from baseload coal and nuclear plants) and the high price of generation during the day (when demand is higher). However, low-cost gas-fired electricity generation and an excess of availability of power from wind and solar in some regions of the country have reduced or eliminated this pricing arbitrage.[225] From a grid reliability standpoint and to avoid curtailment of the excess wind and solar, utility-scale storage such as pumped storage hydropower is needed—yet, the economic incentives are lacking.

Thus, development of pumped storage projects has been stifled because of the lack of a market for the ancillary services they provide and their inability to be classified as transmission assets entitled to cost recovery.[226] While a number of projects in the past 20 years have received FERC preliminary permits[227] and even proceeded to FERC licenses,[228] these projects have been unable to attract financing and have not been built.

FERC's Order No. 890 in 2007, Preventing Undue Discrimination and Preference in Transmission Service, required that non-generation resources be evaluated on a comparable basis to services provided by generation resources.[229] On January 19, 2017, FERC issued a policy statement affirming that storage resources (including pumped storage) can potentially serve as transmission assets and receive multiple revenue streams in an organized market.[230] This represented an evolution and improvement in FERC's approach since it issued the 2008 LEAPS order.

Finally, FERC, on February 15, 2018, issued a final rule aiming to allow energy storage resources (including pumped storage) to more fully participate in organized electricity markets by removing barriers to these resources in the capacity, energy, and ancillary services markets operated by RTOs and ISOs.[231] The rule requires each RTO and ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics and importance to grid reliability of electric storage resources, accommodates their

Grid Reliability and Integration of Variable Renewable Energy xi (2014) (ANL/DIS-14/10), *available at* http://www.ipd.anl.gov/anlpubs/2014/12/106380.pdf.

220. Melanie Guittet et al., *Study of the Drivers and Asset Management of Pumped-Storage Power Plants Historical and Geographical Perspective*, 111 Energy 560, 566 (2016).

221. Dhruv Bhatnagar et al., Sandia National Laboratories, Market and Policy Barriers to Energy Storage Deployment 10 (2013) (SAND2013-7606), *available at* http://www.sandia.gov/ess/publications/SAND2013-7606.pdf.

222. Yang & Jackson, *supra* note 206, at 840.

223. 42 U.S.C. §16422.

224. Nevada Hydro Co., 117 FERC ¶ 61204 (2006), *order on reh'g*, 122 FERC ¶ 61272 (2008).

225. Guittet et al., *supra* note 220, at 561.

226. Sydney P. Forrester et al., *Policy and Market Barriers to Energy Storage Providing Multiple Services*, 30 Elec. J. 50, 51 (Nov. 2017).

227. More than 150 preliminary permits for pumped storage projects have been issued in the past 20 years. *See*, *e.g.*, FERC, *Pumped Storage Projects* (see subheading Existing and Proposed Projects for maps of existing and proposed pumped storage projects), https://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp (last updated Jan. 23, 2017).

228. *See*, *e.g.*, GB Energy Park, LLC, 157 FERC ¶ 62196 (2016); Eagle Crest Energy Co., 147 FERC ¶ 61220 (2014), *order denying reh'g and denying stay*, 153 FERC ¶ 61058 (2015).

229. Preventing Undue Discrimination and Preference in Transmission Service, FERC Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), F.E.R.C. Stats. & Regs. [Regs. Preamble 2006-2007] ¶ 31241, *order on reh'g & clarification*, FERC Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), F.E.R.C. Stats. & Regs. [Regs. Preamble 2006-2007] ¶ 31261 (2007), *order on reh'g & clarification*, FERC Order No. 890-B, 123 FERC ¶ 61299 (2008), *order on reh'g*, FERC Order No. 890-C, 126 FERC ¶ 61228 (2009), *order on clarification*, FERC Order No. 890-D, 129 FERC ¶ 61126 (2009), *appeal vol. dismissed*, National Rural Elec. Coop. Ass'n v. Federal Energy Regulatory Comm'n, No. 08-1278 (D.C. Cir. Feb. 17, 2010).

230. Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, 82 Fed. Reg. 9343 (Feb. 6, 2017).

231. Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶ 61127 (2018).

participation in the organized wholesale electricity markets. While leaving significant aspects of integrating these resources into organized markets to the ISOs and RTOs, the rule moves toward a standard, and more expansive, role for these resources in electricity markets.[232] The final rule will become effective 90 days after it is published in the *Federal Register*.

On the state level, the California Public Utilities Commission (CPUC) in 2013 required its regulated utilities to contract for 1,325 MW of energy storage to balance renewable development, but only storage projects up to 50 MW can qualify. That decision ruled out hydropower pumped storage because pumped storage projects are not feasible at that size.[233] California legislation, A.B. 33, signed into law September 26, 2016, requires the CPUC to evaluate the potential for all types of long-duration bulk energy storage resources, including pumped hydroelectric storage, to help integrate renewable generation into the electric grid.[234] The legislation cites the requirement of California S.B. 350[235] for a 50% renewables portfolio by 2030, raising the specter of widespread curtailment of solar generation to prevent system imbalance.

Such curtailments can occur where there is an excess of supply (e.g., during midday in southern California when solar production peaks) but "conventional generators cannot reduce their output due to technical constraints."[236] To ensure the continued viability of wind and solar alternatives to fossil fuel-powered electricity generation, RTOs and ISOs could develop markets and price incentives for the ancillary benefits provided by hydropower and pumped storage hydropower as a way to ensure grid reliability.[237] As reliance on intermittent renewables grows, this provides an elegant solution. Otherwise, curtailments appear inevitable.[238] As discussed above, FERC appears willing to push the RTOs and ISOs in that direction.

Federal tax incentives for new hydropower development were limited in scope, appear to have run their course, and are unlikely to be revived in the near future.[239] The Internal Revenue Code previously provided a production tax credit (PTC) for renewable energy, including qualified hydropower, marine, and hydrokinetic production, for facilities on which construction began before January 1, 2017.[240] Generally, qualified hydropower production was limited to: (1) incremental production gains from efficiency improvements or capacity additions to existing hydroelectric facilities; and (2) production from new capacity installed at non-hydroelectric dams. The credit was available for the 10-year period beginning on the date a qualified project was placed in service. Wind and geothermal facilities received a PTC of 1.5 cents per kilowatt hour, while qualified hydropower facilities only received 50% of that amount.[241] As an alternative to the PTC, a hydropower project could elect to receive an investment tax credit (ITC) under the Internal Revenue Code equal to 30% of the qualified investment in the project.[242] The ITC was also only available for projects on which construction began before January 1, 2017. Congress did not extend the PTC or ITC for hydropower, marine, or hydrokinetic projects before they expired in 2016.

EPAct 2005[243] established a program to support the expansion of hydropower at existing dams and impoundments through incentive payments. Payments could be made to owners or authorized operators of qualified hydropower facilities for energy generated and sold from such facilities for a period up to 10 years, subject to appropriations. While this program was unfunded for many years, Congress in the 2014 omnibus appropriations bill included a $3.6 million appropriation for the program[244]; another $3.6 million was appropriated in the Consolidated Appropriations Act of 2016 for generation during calendar year 2015.[245] Only facilities in operation by September 30, 2015, qualified for the program,[246] thus limiting its future impact.[247]

Although some commenters call for continuation and even expansion of federal tax incentives for hydropower,[248] these programs are unlikely to offer a long-term or comprehensive solution.[249] Rather, maintaining the existing

232. *Id*.
233. CPUC, Decision Adopting Energy Storage Procurement Framework and Design Program, D.13-10-040 (Oct. 21, 2013).
234. A.B. 33, 2015-2016 Reg. Sess. (Cal. 2016).
235. S.B. 350, 2015-2016 Reg. Sess. (Cal. 2015).
236. Juan I. Perez-Diaz et al., *Trends and Challenges in the Operation of Pumped-Storage Hydropower Plants*, 44 Renewable & Sustainable Energy Revs. 767, 768 (2015).
237. *Id*.
238. Andrew Follett, *California Wastes Tons of Wind and Solar Power Due to Lack of Energy Storage*, Daily Caller, July 24, 2016, http://dailycaller.com/2016/07/24/california-wastes-tons-of-wind-and-solar-power-due-to-lack-of-energy-storage/. *See generally* Collin Doughty et al., California Energy Commission, Bulk Energy Storage in California 9-11, 13-14 (2016) (CEC-200-2016-006), *available at* http://www.energy.ca.gov/2016publications/CEC-200-2016-006/CEC-200-2016-006.pdf; *see also* James H. Nelson & Laura M. Wisland, Union of Concerned Scientists, Achieving 50 Percent Renewable Electricity in California 1 (2015), *available at* http://www.ucsusa.org/sites/default/files/attach/2015/08/Achieving-50-Percent-Renewable-Electricity-In-California.pdf.
239. Peter Maloney, *With Tax Reform on the Table, Senators Prepare Second Push for Energy Storage Incentives*, Utility Dive, Feb. 7, 2017, http://www.utilitydive.com/news/with-tax-reform-on-the-table-senators-prepare-second-push-for-energy-stora/435595/.
240. I.R.S. Notice 2016-31, at 2 (2016), *available at* https://www.irs.gov/pub/irs-drop/n-16-31.pdf; *see* Protecting Americans From Tax Hikes Act of 2015, Pub. L. No. 114-113, div. Q, 129 Stat. 2242.
241. Mark James et al., *Undamming the Federal Production Tax Credit: Creating Financial Incentives for Dam Trading and Dam Removal*, 53 Idaho L. Rev. 93, 97, 116 n.126 (2017).
242. 26 U.S.C. §48.
243. 42 U.S.C. §15881.
244. *See* Consolidated Appropriations Act of 2014, Explanatory Statement 26 (2014), *available at* http://docs.house.gov/billsthisweek/20140113/113-HR3547-JSOM-D-F.pdf.
245. *See* Consolidated Appropriations Act, 2016, Pub. L. No. 114-113, 129 Stat. 2242 (2015).
246. Guidance and Application for Hydroelectric Incentive Payments, 81 Fed. Reg. 24591, 24591 (Apr. 26, 2016).
247. There is a provision included in the Senate energy bill before the 115th Congress that would extend this program to qualified projects that add a turbine or other generating device between 2018 and 2027. *See* S. 1460, 115th Cong. (2017).
248. *See*, *e.g.*, James et al., *supra* note 240, at 97-98.
249. However, if Congress is going to revive the renewable energy tax credits, hydropower should be treated equally with solar, wind, and other renewables, which has not been the case. *See id*.

hydropower fleet and expanding hydropower resources may depend on reform of the organized markets to more accurately value and compensate hydropower owners and developers for the grid services they provide as well as energy and capacity. This is particularly true for utility-scale pumped storage hydropower, which not only provides grid support, but has the potential to facilitate expansion of wind and solar resources by balancing and integrating these renewable sources into the electric system. Both FERC and some states appear to be making slow progress toward appropriately compensating the grid services provided by hydropower projects. These market reforms should include the following:

- RTOs and ISOs should enact market rules to accommodate the participation of energy storage (including hydro pumped storage) in energy markets, consistent with FERC's final rule.
- RTOs and ISOs should establish new products and reform existing products that would adequately compensate ancillary services such as those provided by hydropower.
- State public utility commissions should direct their regulated electric utilities to evaluate the need for and benefits of grid-scale storage such as pumped storage hydro.[250]
- States should consider including pumped storage hydro as transmission assets entitled to cost-of-service rate recovery in their transmission planning as an alternative to construction of new transmission lines.

V. Conclusion

Hydropower is the largest renewable resource in the United States and is an essential component to decarbonize the electric grid. It is one of the few baseload renewable resources, and provides operational flexibility to integrate other, intermittent renewables into the grid. As electricity demand continues to grow in the future, robust hydropower resources will be essential to achieving a reduced carbon electric grid—not only because of their current market share and proven capabilities for more than a century, but also because of their ability to maintain a stable, functional grid, and to ensure integration of intermittent renewables such as wind and solar. Quite simply, the United States will be unable to achieve renewable energy targets for the electric grid without hydropower.

There is ample opportunity to expand hydropower in the United States in an environmentally responsible way. These opportunities include upgrades at existing hydropower facilities, installation of new generating equipment at existing infrastructure, construction of pumped storage projects, and even selective development of new conventional hydropower at greenfield sites—with the assistance of new technologies and management strategies to protect and mitigate impacts to environmental resources. In addition, with so many upcoming relicensing proceedings before FERC, it is crucial that project owners remain invested in continued operation of these projects to maintain the current hydropower fleet.

Without regulatory and market reforms to benefit hydropower, however, new and continued investment in hydropower in the United States will not be realized and our ability to decarbonize the electric grid will be diminished. Regulatory reforms are needed to recognize hydropower as a renewable energy resource and the climate benefits it provides, consolidate and coordinate licensing activities, provide certainty and schedule discipline in regulatory proceedings, implement new efficient approval processes for upgrades to existing hydropower projects where appropriate, promote development of needed pumped storage through a streamlined and focused licensing process, incentivize new hydropower at existing dams by focusing the licensing process and protecting current uses of existing infrastructure, and promote MHK technologies. From a markets perspective, reforms are needed to value and compensate hydropower operators for the essential grid services they provide. These reforms will incentivize new hydropower developers and existing owners alike to invest in new hydropower generation.

250. *See* Clearing Up No. 1821 (Energy NewsData, Seattle, Wash.), Oct. 13, 2017, at 7.

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