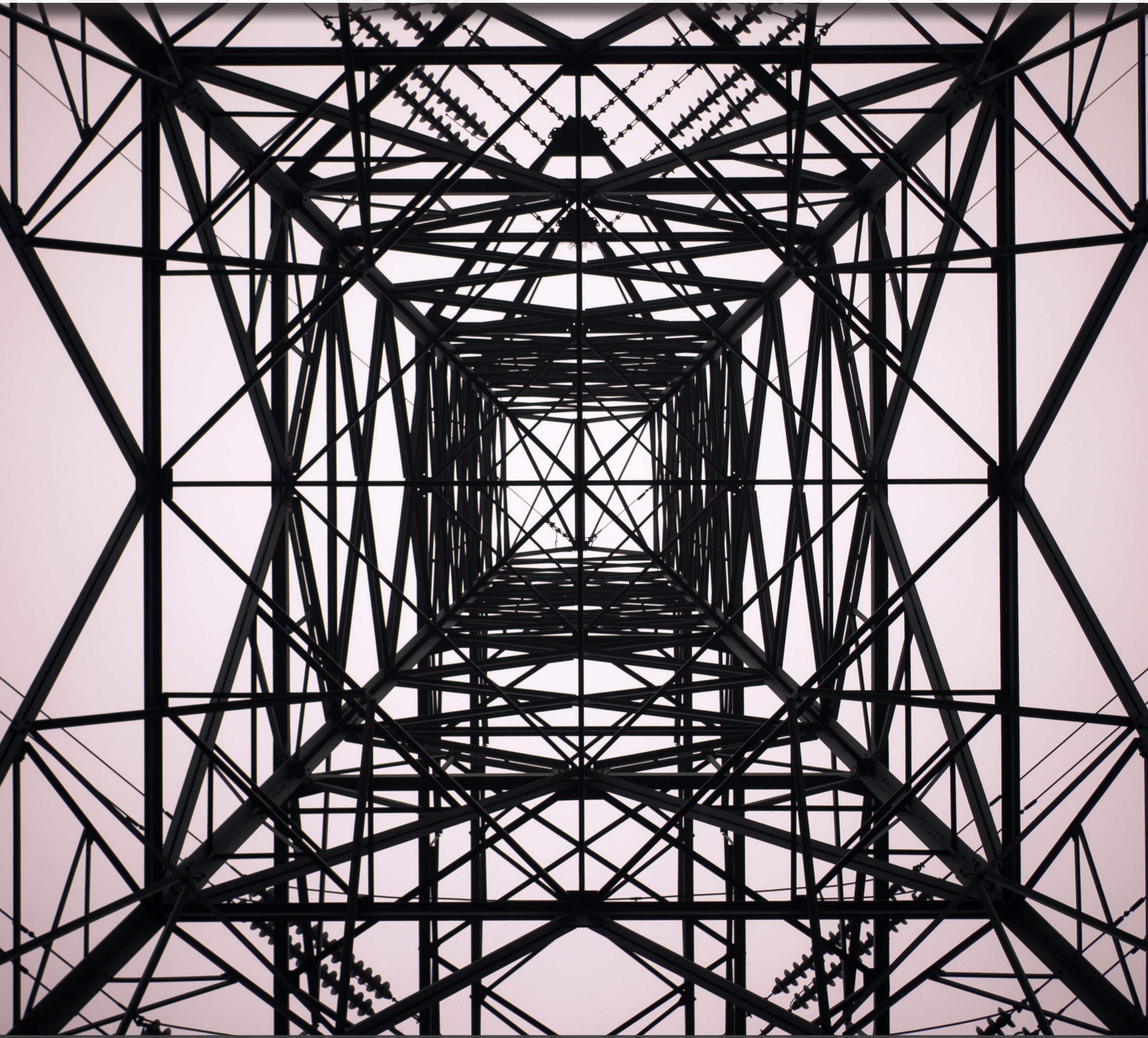
SEVENTH POWER PLAN MIDTERM ASSESSMENT



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Northwest **Power** and
Conservation Council

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SECTION 1:
EXECUTIVE SUMMARY

The primary purpose of the midterm assessment is to check on the region's progress in implementing the Seventh Northwest Power Plan, which the Council issued in early 2016. The Seventh Plan had many recommendations and the region has made significant progress in implementing the plan's resource strategy. While some circumstances have changed since the plan was published, nothing calls into question the fundamental strategy described in the plan.

MAJOR FINDINGS

The Seventh Plan's recommended resource program was, and remains, the preferred program under a wide range of circumstances. An in-depth examination of recent developments and comparisons to the forecasts made in the Seventh Plan confirms that the recommended resource strategy still produces a least-cost and reliable system, and the region will benefit substantially by continuing to implement the Seventh Plan. This assessment includes a review of the Action Plan (Chapter 4 of the Seventh Plan) and reports on plan implementation progress. Some recommendations in the Action Plan have been completed; progress has been made on most of the recommendations; and progress has been limited on a few. Overall, much has been accomplished, and the region is well-positioned to fully implement the recommended resource strategy.

Despite this good start, there are concerns about elements of the resource strategy going forward. Energy efficiency has been a substantial part of the resource strategy for every power plan since the first plan in 1983. An estimated 408 average megawatts of energy efficiency was developed in 2016-2017, exceeding the first two-year milestone of 370 average megawatts. However, there is reason to be concerned because the Council's efficiency goals grow year to year, and forecast program savings are flat to declining. If savings fall noticeably short of the Seventh Power Plan targets, other sources will be needed to fill the gap or the region will likely face adequacy problems or higher costs.

Substantial progress has been made to identify barriers to developing demand response and understanding the regional potential of this resource. And while many regional utilities have demand response incorporated into their Integrated Resource Plans, the region has yet to make substantial progress on the recommended 600 megawatts of incremental demand response identified in the 7th Plan.

Since the plan was finished, we have seen additional announced retirements of coal generation and a larger–than-expected reduction in the cost of wind and solar generating technologies. The market price for natural gas continues to be depressed, resulting in a low cost for natural gas generation and low market prices for electricity. Increased generation from existing gas plants and new wind and solar generation continue to displace existing coal generation and have held down regional carbon dioxide emissions. Additional resource retirements are expected to have a substantial impact on reducing emissions.

The region faces a potential shortfall in resources needed to meet electricity demand after 2020 when the Boardman and Centralia 1 coal plants are scheduled to be retired. Quantifying the types and amounts of new resources needed to maintain an adequate power supply is beyond the scope of the Council’s annual adequacy assessment and of this midterm assessment. However, in their long-term plans, regional utilities have identified a wide range of new resources that are generally in line with the Council’s Seventh Power Plan resource strategy. The least-cost approach to maintaining system adequacy continues to rely heavily on demand response and on energy efficiency.

The region is on track to meet the goals and implement the recommendations in the Council’s Seventh Plan. The work to accomplish this has been significant. However, these goals will require more effort and resources. The Council and the region will continue to adapt and implement the resource strategy to ensure an adequate, efficient, economic, and reliable power system for the Northwest.

SECTION 2:
ACTION PLAN IMPLEMENTATION PROGRESS

Contents

INTRODUCTION

The Seventh Power Plan recommends that regional entities take specific actions to implement the plan with a focus on the first five to six years of the 20-year plan. These recommendations are summarized in the Chapter 4 – Action Plan[1], which proposed activities focused on resource strategy, regional efforts, Bonneville Power, regional partners, and the Council itself. This section of the midterm assessment provides a high-level summary of the progress in each area.

RESOURCE STRATEGY

The Seventh Plan proposed eight actions to implement a resource strategy that provides a least-cost mix of resources to provide an adequate and reliable power supply that is highly adaptable and reduces risk to the region.

RES-1: Achieve regional goal for cost-effective conservation resource acquisition

In 2016 and 2017, the region achieved 408 aMW of energy efficiency. This surpasses the first two-year milestone of 370 aMW. While the region is currently on track, more work is needed to meet the six-year goal of 1400 aMW.

Achieving the Seventh Plan goals for energy efficiency is going to rely on a mix of program savings, contributions from NEEA savings, and other savings through improvements in codes and standards or other market advancements. Based on initial reports, projected program budgets and savings for the next two years are expected to stay relatively flat, with a projected savings of 365 aMW in 2018 and 2019. Program savings have been shown to be closely tied to program budgets, meaning that if program budgets continue to remain flat, or decline, program savings are likely to do the same.

Based on these projections, and assuming similar programmatic accomplishments in 2020 and 2021, the region will likely need more than 250 aMW of energy efficiency to come from NEEA efforts and other market change. NEEA projects 60 aMW of savings in 2018 and 2019. Assuming similar NEEA savings in the final two-year period, this would require around 150 aMW to come from other sources of market change. Based on the residential markets studied to date, the region has not seen any positive market change not already captured by utility programs and NEEA. While these savings may, indeed, develop, it is an area of uncertainty.

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[1] https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap04_actionplan_12.pdf

RES-2: Implement recommended methodology for evaluating cost-effectiveness of conservation measures

In April 2016, the Regional Technical Forum adopted an approach for cost-effectiveness that is consistent with the Seventh Power Plan. Council staff also conducted a training in July 2016 for Washington Commission staff and Department of Commerce staff to help them understand the Council's methodology. Council staff assisted the Department of Commerce in updating the rules of the 2007 Washington Energy Independence Act that require utilities in the state to acquire all cost-effective conservation in a manner consistent with the Council's Plan. Finally, Council staff engage in conservation or integrated resource planning advisory committees with several regional utilities and, through those forums, encourage these utilities to adopt methodologies consistent with the Seventh Plan. Many utilities and program operators are now directly evaluating the capacity value of energy efficiency when considering this resource.

RES-3: Develop and implement methods to identify system–specific, least-cost resources to maintain resource adequacy

Other Related Action Items: ANLYS-11

The region has demonstrated progress on this recommendation. Bonneville looked at resource adequacy in its 2018 Resource Program. Utilities have integrated some of the considerations into their Integrated Resource Plans (IRP). Since the Seventh Plan was published, utility regulators have also consulted with the Council on measuring resource adequacy.

The Council has also commented on utility IRPs (ANLYS-11) as appropriate to encourage utilities to develop and implement these methods.

RES-4: Expand regional demand response infrastructure

Since the release of the Seventh Plan, all the regional Investor Owned Utilities have released Integrated Resource Plans (IRP) that show a new or continuing need for demand response. In addition, Bonneville's recent Resource Program found demand response (DR) to be a priority resource in the summer. A summary of the planned demand response by IOUs and BPA is provided. "Start Date" indicates when the utility will anticipate needing the DR, where "continuing" indicates continuing programs that are currently being deployed (i.e. not new incremental DR).

Utility	Amount DR (MW)	Start Date
BPA	131 (summer)*	2020
Puget Sound Energy	103 (winter)	2023
Portland General	69 (summer), 77 (winter)	2021
PacifiCorp	500 (summer)	Continuing
Avista	44 (winter)	2025
Idaho Power	390 (summer)	Continuing
Northwestern Energy	TBD – winter	TBD

* Portfolios 2 and 3

As is, it is not likely the region will achieve the 600 MW of incremental demand response recommended in the Seventh Plan. The Council will continue to engage in IRP advisory committees and, through the Demand Response Advisory Committee, explore the ways to expand the regional DR infrastructure.

RES-5: Support regional market transformation for demand response

In NEEA's draft strategic plan for 2020-2024, NEEA is exploring how it may engage to enable communications with connected loads and devices. By doing this, it will enable utilities to more cost-effectively deploy demand response products. The plan encouraged the regional utilities, that are NEEA funders, to support this effort and include related activities in NEEA's 2020-2024 Business Plan. Without this support, any substantial movement in market transformation for DR is unlikely to occur.

RES-6: Expand renewable generation technology options considered for Renewable Portfolio Standards (RPS) compliance

Other Related Action Items: ANLYS-11, ANLYS-13

Wind continues to make up the majority of the regional capacity used for state-level renewable portfolio standard (RPS) compliance. However, utilities have been exploring resource alternatives to comply with future RPS obligations through requests for proposals, unbundled REC procurements, and integrated resource planning. Resources include Columbia Gorge and Montana wind, repowering existing wind, solar PV, geothermal, biomass, upgrading existing hydropower, and offshore wind.

Council staff participates in the development of utility IRPs (ANLYS-11) and tracks new and proposed resources for RPS compliance in its generating resource datasets, which are updated on an ongoing basis (ANLYS-13).

RES-7: Regional Carbon Emissions

The Seventh Plan anticipated regional compliance with the Environmental Protection Agency's Clean Power Plan, which limits carbon dioxide emissions. Since the plan, implementation of the Clean Power Plan has become uncertain. However, the general guidance of the least-cost strategy for carbon dioxide (CO2) emission reduction in the plan remains relevant. In this case, it was recommended that should states or the region seek CO2 emission reductions in the power system, the most cost-effective manner would be to reduce the dispatch of existing coal generation and increase reliance on both existing and new natural gas generation. Washington and Oregon policy makers have considered legislation to target reducing CO2 emissions, but no legislation has been passed as of this assessment. There is also potential for an initiative in Washington with the intent of reducing CO2 emissions. The Council will continue to monitor regional actions taken to reduce CO2 emissions and track and publicize the impacts of these policies on the regional carbon emissions.

RES-8: Adaptive management

The plan recommended using several methods to monitor the regional energy system and adapt planning accordingly. As part of this recommendation, the Council has completed annual resource adequacy assessments. It continues to release annual conservation progress reports. There have been updates on demand response activities in the region, but it has not been amenable to an annual report format yet.

REGIONAL RECOMMENDATIONS

The Seventh Plan recommended the region implement actions beyond those identified in the resource strategy related to conservation, demand response, and adequacy planning. These recommendations were broadly targeted at the Bonneville Power Administration, the Northwest states, utilities, utility regulators, and other regional organizations. There has been substantial progress on these recommendations since the plan was published.

Conservation

Related Action Items: REG-1, REG-2, REG-5, REG-6, REG-7, REG-8, REG-9, REG-10, REG-11

End-use Load Research

The action plan included many recommendations regarding energy efficiency. One key recommendation was an update information on end-use loads, which would provide more information about the potential of conservation. Eight regional utilities, the Energy Trust of Oregon, and the Bonneville Power Administration are funding a project, coordinated and facilitated by NEEA, to develop new residential and commercial-sector end use load research (REG-1). This work not only refines information about potential of energy efficiency, it provides added value in load forecasting, demand response, and transmission and distribution planning activities.

The residential-sector end-use load research began in 2017 and will span a five-year data collection period beginning 2018 and targeting 400 sites chosen for specific end uses and equipment combinations. The commercial-sector research is in the formative scoping stages and is targeting about 100 sites. It is a major milestone in regional coordination that will update data that may be as much as 30 years old. In addition, the RTF has developed and deployed a methodology to evaluate the quality of hourly profiles it uses to estimate energy savings (see ANLYS-10).

NEEA

The Seventh Plan recommended that the Bonneville Power Administration, utilities, and the Energy Trust of Oregon continue to support NEEA. NEEA is currently in the process of developing its scope of work and business plan for the 2020-2024 timeframe. The final business plan is scheduled for approval at its annual board meeting in December 2018. Most of the utilities that currently support NEEA are anticipated to continue that support, apart from Cowlitz County PUD, which stopped funding NEEA at the end of 2017. Some utilities in the Northwest did not support NEEA when the Seventh Plan was published. None of those utilities have signed up to support NEEA since the publication of the plan.

Regional activities coordinated by NEEA include regional sector specific stock assessment (REG-7), understanding the impact of codes and standards on load forecasting and regional conservation goals (REG-8), and developing strategies to coordinate energy-efficiency planning within the region (REG-10).

In March 2018, NEEA released a Residential Building Stock Assessment. The Commercial Building Stock Assessment survey is planned for later this year. The Seventh Plan called for stock assessments in the industrial and agriculture sectors as well. But no systematic assessments are in the works, so data on those sectors may not be available by 2020 for inclusion in the Council's Eighth Plan development. In lieu of this, Council staff have been conducting some research on specific subsets of the industrial sector (see ANLYS-1).

NEEA periodically updates detailed estimated savings from state building codes and federal and state standards based on a variety of market data, RTF analyses, and market models. Estimates of savings from buildings codes and equipment standards are included as savings in the RTF Regional Conservation Progress report (see RES-1). The data are available to regional utilities and others to incorporate into load forecasts, but utilities are only beginning to use the data to adjust their load forecasts for the impact of adopted codes and standards.

The plan recommended NEEA initiate three regional strategy efforts by 2016. As of 2018, NEEA has initiated two regional market strategies: one for commercial lighting and one for consumer products. These strategies have been developed using market data from several sources, along with input and ideas from regional utilities, the Energy Trust of Oregon, the Bonneville Power Administration, the Council and trade allies. The results of the initial lighting strategy have led to a second round of emerging cooperative opportunities in lighting.

RTF

The Regional Technical Forum maintains a library of unit energy savings and standard protocol measures that provide energy savings estimates for utility programs (REG-5). These savings are based, in large part, on evaluations conducted by the region's utilities. Since 2016, the RTF has relied on evaluations from the Bonneville Power Administration, the Energy Trust of Oregon, Puget Sound Energy, Seattle City Light, Tacoma Public Utilities, the Northwest Energy Efficiency Alliance, and others to support updates to its measure library.

Additionally, the RTF maintains Operative Guidelines that outline quality standards for savings estimation and provide a basis for reliable use of those estimates in efficiency programs. The RTF continually updates its Guidelines to ensure they are up to date with the latest practices. The last update was in January 2018. The RTF is planning another update for Q1 of 2019, which would have specific focus on its impact evaluation section.

The RTF completed its Regional Conservation Progress Report for 2016 and 2017 (REG-6). In addition to capturing the program savings from the Bonneville Power Administration, the Energy Trust of Oregon, and other regional utilities, the RTF captured data from NEEA on additional efficiency occurring outside of direct programs, savings from codes and standards, and updates to savings based on evaluations. The RTF also estimated the contribution of the total conservation to the system peak capacity needs. Results are provided in RES-1 above.

Other Regional Recommendations on Conservation

Utilities and other entities in the region (and around the country) are experimenting with whole building energy efficiency programs (REG-9). The RTF is currently exploring a standard protocol for whole building savings estimates. Also, the Conservation Resource Advisory Committee met in the fall of 2018 to consider items related to whole building energy efficiency programs.

The Northwest Energy Efficiency Leadership Forum (NEEL) considered several approaches to explore alternative business models (REG-11). There is still interest in the topic in general, but the idea of orchestrating a Northwest-wide comprehensive review of the topic was abandoned. However, some activities are occurring on this topic in smaller forums. The Oregon Public Utility Commission is investigating how developing industry trends, technologies, and policy drivers may impact the existing electricity regulatory system. The Northwest Public Power Association briefed NEEL on results of a survey that indicate large numbers of utilities are considering rate structure changes, including shifts to higher fixed charges.

Demand Response

Related Action Items: REG-3

The Council, with advice from the Demand Response Advisory Committee (DRAC), created a template to collect data on past and planned DR programs from regional utilities. The data collected include types, amounts by season, specifics on deployment strategy, and cost. This data will be collected annually, with the first request having occurred December 2017.

Adequacy and Planning

Related Action Items: REG-4

The Council has acquired balancing reserve data from regional utilities and, to the extent possible, has incorporated those reserves into its planning models (REG-4). Balancing reserves provide incremental and decremental generation needed to maintain within-hour load/resource balances. The redeveloped version of the Council's GENESYS model is being designed to incorporate balancing reserves in a more direct way.

MODEL CONSERVATION STANDARDS

Related Action Items: MCS-1, MCS-2, MCS-3, MCS-4, MCS-5, MCS-6, MCS-7

The model conservation standards describe standards for regional conservation programs. The Seventh Plan recommends that conservation programs ensure all cost-effective conservation is acquired (MCS-1), develop programs to assess and capture distribution efficiency savings (MCS-2), actively participate in the processes to establish and improve state efficiency codes and federal efficiency standards (MCS-3), develop a regional work plan to focus on ensuring adoption of emerging technologies (MCS-4), engage in federal and state standards (MCS-5), develop best-practices guides for design and operations of emerging industries (MCS-6), and monitor and track code compliance in new buildings (MCS-7). Progress on these recommendations has had mixed results since the plan.

The Council facilitated and summarized work focused on identifying and analyzing under-served market segments (MCS-1). The report was released for public review and comment. The report details some of the Northwest utilities that are working to revise existing or design new programs to better reach under-served segments in their service territories. The work addressing gaps is being taken up by regional utilities and other stakeholders because under-served segments differ by service territory.

Programs to assess and capture distribution efficiency have not progressed significantly since the release of the Seventh Plan (MCS-2). The Bonneville Power Administration has not completed a distribution efficiency assessment and does not have near-term plans to complete this assessment.

Utility regulators are increasingly aware of the value of utility and NEEA programs to demonstrate promising technology and practices that may not yet be cost-effective (MCS-3). Utilities generally rely on NEEA to coordinate code development work. Some program operators, like the Energy Trust of Oregon, work directly with local code jurisdictions to improve implementation of new provisions in the codes through their new buildings programs.

The Regional Emerging Technology Advisory Committee (RETAC) of NEEA quickly developed a regional work plan to focus on emerging technologies (MCS-4). One of the primary results is a new database of emerging technologies in the region. Each technology in the database has a set of "readiness" rankings to help the region with decision-making related to emerging energy efficiency technologies.

Much of the federal standard development has slowed in recent years, but the Council continues to engage where appropriate (MCS-5). One new rulemaking is underway in 2018: The Variable Refrigerant Flow Multi-Split Air Conditioners and Heat Pumps Working Group.

There has been a lack of resources and funder interest for NEEA to develop best-practices guides for emerging industries (MCS-6). This is in part due to challenges in defining “best practice.” There are a couple of activities that may improve our understanding of these emerging industries. The Council has conducted numerous surveys to better understand energy consumption in the cannabis industry. Results from these surveys were presented to the Council in June 2018.The Bonneville Power Administration has initiated research on data center energy consumption and efficiency opportunities.

NEEA has initiated new building code compliance studies to understand code adoption in Idaho and Montana, which are expected to be completed early in 2019 (MCS-7). NEEA is also planning to conduct studies for Oregon and Washington in 2019.

THE BONNEVILLE POWER ADMINISTRATION

Conservation

Related Action Items: BPA-1, BPA-5, BPA-6, BPA-7

The Bonneville Power Administration’s Energy Efficiency Plan projected it would meet 42 percent of the regional energy efficiency goal as established in the Seventh Plan through a combination of program, NEEA, and other market savings. This projection is 581 aMW by 2022. In 2016 and 2017, the agency reported 136 aMW of program savings (BPA-1). In its 2018-2019 rate case, the agency reduced its Energy Efficiency Incentive (EEI) budgets by 4 percent from the previous rate case budget with the intent of relying on an increase in self-funding. Additionally, since 2016 and 2017 savings represent an overachievement of *program* savings as estimated in its Energy Efficiency Plan, the Bonneville Power Administration plans to reduce its funding for energy efficiency in 2020 and 2021, likely resulting in less program savings during that same two-year period. Despite this planned reduction in program savings, the agency expects to meet its six-year goal of 581 aMW with 229 aMW of savings through NEEA and market momentum activities. Bonneville is currently updating its Energy Efficiency Action Plan based on results of its recently completed Resource Program to better inform how it can meet is goals while best serving its energy and capacity needs.

The Seventh Plan recommended that the Bonneville Power Administration discuss both the costs and benefits, including the long-term value, of energy efficiency in budget-setting forums (BPA-5). Bonneville used its 2018 Resource Program to evaluate the value of energy efficiency for meeting the future needs of the agency. The results informed a shift in focus toward measures that produce higher value savings for meeting the agency’s obligations. These results are being taken into consideration in the current BPA Integrated Program Review. BPA also developed a set of models to help its utility customers evaluate the costs and benefits of energy efficiency from the individual utility perspective.

The Seventh Plan recommended BPA assess its current energy efficiency implementation model, especially regarding proportional funding (BPA-6). Bonneville has not commissioned a study as described in the Action Plan; however, some aspects of BPA-6 have been considered. BPA has reaffirmed the current funding model through the Focus 2028 activity[2] and have made changes to the rollover and bilateral transfer policies to help customers optimize their use of EEI allocation.

The plan directed Bonneville and the Council to develop a report that identifies economic, contractual, motivational, institutional, and political barriers to acquisition and implementation of conservation (BPA-7). The Council is currently working on a white paper on the value of conservation with support from Bonneville that may be partially responsive to this recommendation. There are no other efforts underway aside from that.

Resource Adequacy and System Analysis

Related Action Items: BPA-2, BPA-8, BPA-9, BPA-10

The Seventh Plan recommended that BPA update methods to identify least-cost resources, including looking at incremental energy efficiency and demand response (BPA-2). In its 2018 Resource Program, BPA identified its resource requirements and focused on energy efficiency and demand response as the primary resources to meet its upcoming needs. As part of the 2018 Resource Program, the agency contracted with ITRON to enhance its load forecasting model (BPA-10).

The Seventh Plan also recommended that BPA conduct an analysis of its operating reserve requirement (BPA-8). The agency does not anticipate needing more than 900 MW of incremental reserves for its balancing authority and thus can serve all operating reserve requirements with the federal system. This result is part of the needs assessment that was included in the 2018 Resource Program. The extent to which this can be adapted to the Council's planning process has not yet been determined and will partially depend on the redevelopment of GENESYS.

The plan recommended that BPA work with its customers to create incentives to help mitigate generation oversupply conditions (BPA-9). No incentive has been implemented as of the writing of this assessment.

Demand Response

Related Action Items: BPA-3, BPA-4

The Seventh Plan recommended that BPA assess demand response potential and barriers, which it completed in the spring of 2018 (BPA-3). The results from the potential assessment were fed into its 2018 Resource Program. Through these efforts, BPA has greatly improved its understanding of the opportunities and challenges demand response may bring to its system. How that affects the way the agency acquires demand response, or what resource acquisition rules they use, is yet to be determined. BPA has expanded the use of demand response on its system through the South of

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[2] https://www.bpa.gov/Finance/FinancialPublicProcesses/2028/Pages/default.aspx

Allston pilot program and continues to explore commercial needs for expanding demand response infrastructure.

The Seventh Plan also recommended BPA add to the publicly available data on its website demand response data. This was not the chosen method of sharing these data. Instead, BPA shared with the Council its historical DR data (see REG-3) through the data collection template created with the Demand Response Advisory Committee (BPA-4). The DRAC was not established when the plan was released and was therefore not identified as a venue for releasing these data. The result is basically the same; if demand response plays a larger role in the future dispatch of Bonneville's system this method of delivering these data may need to be revisited.

COUNCIL ACTIONS

Demand Response

Related Action Items: COUN-1, COUN-2

The Council formed the Demand Response Advisory Committee in August 2016 (COUN-1), with the first meeting held December 2016. Since then, the committee has met quarterly and will continue to do so throughout the Eighth Plan development process.

The Council also continued to work with the Regulatory Assistance Project to support the Pacific Northwest Demand Response Project (PNDRP). Its most recent meeting was held in June 2018. (COUN-2)

Resource Adequacy and System Analysis

Related Action Items: COUN-3, COUN-4, COUN-5, COUN-6, COUN-7, COUN-11

In 2017, the Resource Adequacy Advisory Committee (RAAC) discussed several alternatives to the current resource adequacy standard (COUN-3). The discussion is ongoing, including consideration of metrics recently proposed by NERC and metrics related to the cost of curtailing load. The most recent adequacy assessment revisited the availability of generation and the capability of transmission to import power into the Northwest (COUN-4). The sensitivity of the adequacy results to the assumed availability of imports continues to be a key factor in the adequacy assessment.

The methodology to calculate the adequacy reserve margins for the Regional Portfolio Model has been presented and discussed in technical forums, including with the Institute of Electrical and Electronics Engineers (IEEE), but has not been taken through an advisory committee review (COUN-5). That work will be more relevant when the redevelopment of GENESYS is completed. Similarly, the review of the methodology used to calculate the associated system capacity contribution will be taken up in the next year or two (COUN-6).

The Council continues to participate in the River Management Joint Operating Committee's (RMJOC) work on climate change to develop forecast changes to both temperature and river flows under various possible future climate scenarios. During the development of the Seventh Plan, it was expected that data downscaled to the Northwest would be available mid-2017. Now it is anticipated that this work should be completed by 2019, when the Council will assess the impacts (energy supply, cost, and river flows) of selected climate scenarios (COUN-11). In part because of the delay in downscaled Inter-governmental Panel on Climate Change data, the Council, in conjunction with the Pacific Northwest National Lab, has developed a method to approximate climate change impacts to river flows and associated rule curves. This methodology will allow for alternatives for addressing climate change in the next power plan.

The Seventh Plan recommended that the Council, with assistance from the region, perform an analysis of operating reserve requirements (COUN-7). The Council anticipates doing this in the 2021 Power Plan.

Other Council Actions

Related Action Items: COUN-8, COUN-9, COUN-10, COUN-12

Coordination with Western Electricity Coordinating Council (WECC) is ongoing (COUN-8). This includes working with WECC's Loads and Resources Subcommittee on their development of adequacy guidelines and assessments. The Council has also supported WECC in the Western Interconnection Gas-Electric Interface Study with staff representation on the Technical Advisory Committee. This study focuses on identifying and modeling the impact of potential natural gas system disruptions on the bulk electricity system.

Council staff has continued its collaboration with various organizations in California, including the California Independent System Operator (CAISO) and Northwest entities to understand a regional Energy Imbalance Market. (COUN-9) The energy imbalance market established by PacifiCorp and the California ISO has expanded since the Seventh Plan. There are also ongoing discussions about the potential of a larger Western centralized market. The Council continues to monitor changes in regional markets.

BPA and the Council reviewed and reaffirmed the existing policy on implementation of Section 6(c) of the Northwest Power Act. This review culminated in a Memorandum of Understanding signed in February of 2018. (COUN-10)

The Council, in coordination with PNUCC, has worked with regional utilities to develop a methodology for a regional estimate of the deferred transmission and distribution value from distributed resources as recommended in the plan (COUN-12). Later this year the Council will send out a data request to utilities to gather the inputs needed to calculate the deferred values.

ANALYTICAL CAPABILITY

The Council's power plan is rich in data and model driven. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. The Seventh Plan contained recommendations to maintain and improve planning data for the region.

Load Forecasting

Related Action Items: ANLYS-1, ANLYS-2, ANLYS-4, ANYLS-5

The long-term load forecast has been improved by updating and refining the base conditions for industrial consumption (ANLYS-1); examining emerging markets, including behind-the-meter solar and battery technologies, Cannabis production, electric vehicles, data centers (ANLYS-2); and enhancing the electrification of transportation (ANLYS-5). These enhancements have been presented to the Council and will be reflected in the understanding of conservation potential and the end-use of electricity, which will be used in the development of the Eighth Plan.

The Council, with advice from the Resource Adequacy Advisory Committee, updated the forecast to reflect short-term dynamics while accounting for anticipated energy efficiency achievement (ANLYS-4). This updated load forecast was used in the Council's resource adequacy assessment.

Conservation

Related Action Items: ANLYS-3, ANLYS-6, ANLYS-7, ANLYS-8, ANLYS-9, ANLYS-10

The Council hired a consultant to explore the development of an end-use conservation model (ANLYS-3). The recommendation was to continue the current methodology used to develop conservation curves but enhance the connection to the end-use load forecast.

As recommended in the plan, an assessment of water and wastewater energy consumption was conducted and summarized in a report (ANLYS-9). The assessment includes a database of all facilities in the Northwest; an estimate of the total regional consumption for these segments; a breakdown of energy consumption by end use; and energy efficiency potential estimates.

The Seventh Plan recommended establishing a forum to share research activities and identify and fill research gaps for conservation (ANLYS-6). The Council has not made progress on this recommendation. The work of the Regional Emerging Technology Advisory Committee is a significant step forward in this direction (see MCS-4). The Council also continues to explore research coordination, such as that with the Northwest Research Group, to make connections and identify gaps.

The RTF assessed the assumed baselines of conservation potential in its Regional Conservation Progress Report (ANLYS-7). In 2016, the RTF surveyed utilities to understand what data may be available regarding electricity consumption by end use. In 2017 (for the 2016 report), the RTF asked for reporting on baseline consumption. Only a handful of entities were able to provide any information, although no entity was able to provide fully complete data for a pure comparison of savings to the Seventh Plan baseline. Data are typically available for residential measures and those that rely on RTF analysis. The remainder of measures (which represent more than half of the savings) are complex, as many baselines are specific to an individual facility.

The RTF determined the value of collecting the data significantly outweighs the costs and increased burden on utilities. Therefore, the focus going forward will be on total regional savings assessments, where available, to provide the most accurate picture of achievements from the power plan baseline.

The RTF's Operative Guidelines include a section on estimating costs and benefits from energy efficiency measures. This includes direct costs of the equipment, as well as other non-energy impacts such as water savings (ANLYS-8). In the January 2018 update, the RTF refined this section to ensure consistency with the Council's environmental methodology. The RTF is planning to conduct a review of all its measures against these guidelines to ensure symmetrical treatment of both costs and benefits. The RTF aims to have this complete in early 2019.

The RTF has made significant progress on including the reliability of capacity savings estimates in RTF guidelines (ANLYS-10). In April 2018, the RTF released a framework to provide systematic review of its measures for estimating the reliability of the capacity estimate. Along with the framework, the RTF released 36 recommendation memos that included detailed reviews for each RTF unit energy savings measure and recommendations for improving reliability. The RTF received stakeholder comments on the framework and recommendation memos, which provided good direction for next steps. The RTF plans to incorporate key concepts from the framework in the next update of its Operative Guidelines (Q1 2019). Additionally, the RTF plans to use the recommendations to guide the development of hourly profiles that will better reflect the capacity savings from measures. This work is intended to complement the end-use load research (see REG-1).

Generating Resources

Related Action Items: ANLYS-11, ANLYS-12, ANLYS-13, ANLYS-14, ANLYS-15, ANLYS-16, ANLYS-17, ANLYS-18, ANLYS-19

The Council updates the various generating resource datasets on an ongoing basis. This includes updates on solar photovoltaic (ANLYS-17) and natural gas-fired technology (ANLYS-18). Updates on these and other technologies are included in this midterm assessment. Efforts to streamline and consolidate the datasets have been explored and improvements are underway (ANLYS-13).

The Council continues to monitor and track the potential and cost of emerging technologies (ANLYS-14). There have been numerous presentations and panels from emerging technology subject matter experts and tours of potential sites and pilot projects associated with monthly Council meetings, including technologies such as enhanced geothermal systems, small modular reactors, pumped hydro storage, battery energy storage, and ocean energy.

Through extensive outreach and collaboration with stakeholders, the Council developed a white paper on the value of energy storage to the future power system (ANLYS-16). Part of the November 2 GRAC meeting was a workshop on ocean energy technologies (specifically offshore wind and wave energy) to explore issues beyond cost and technical feasibility. At the end of this workshop, participants interested in discussing these issues further were directed to Pacific Ocean Energy Trust (POET), which planned to initiate future collaborations (ANLYS-15).

An effort to upgrade the MicroFin revenue requirements model is underway (ANLYS-12). The goal is to preserve the functionality and accuracy of the model while improving and streamlining the formulas, data, functionality, and user interface. One of the primary deliverables of the redevelopment will be a user's guide that will make it easier to share the model with stakeholders and interested parties. The Council plans to convene the Generating Resources Advisory

Committee in early 2019 to review the redeveloped model. This is later than the target date in the Seventh Plan, but it is anticipated to be done in time for use in developing the 2021 Power Plan.

Development of the natural gas system since the Seventh Plan is not anticipated to have substantial impacts on the regional power system (ANLYS-19). NW Natural has completed the North Mist Expansion Project in Northwest Oregon. The project includes developing a new reservoir (2.5 bcf of storage), a compressor station, and a 13-mile pipeline to the Portland General Electric Port Westward natural gas power plant complex. This addition to the natural gas storage system will be ready for the 2018/2019 winter.

The Council continues to monitor the potential for Liquified Natural Gas (LNG) exports. The proposed Jordan Cove LNG project, located in Coos Bay Oregon, would include a liquefied natural gas export terminal for transport to world markets and a new 1.2 bcf/day natural gas pipeline (Pacific Connector). FERC denied approval for the project in 2016, but the project has re-applied and is expecting a decision from FERC in late 2018. There are also 14 proposed LNG export facilities in British Columbia, Canada, which could affect LNG exports from the region. The Council will continue to monitor the efforts to establish LNG export facilities that would affect the regional supply of natural gas.

System Analysis

Related Action Items: ANLYS-21, ANLYS-22, ANLYS-23

The Council continues to review its analytical tools used to develop and support the power plan (ANLYS-21). This includes redeveloping the GENESYS model (ANYLS-22) used for resource adequacy analysis; updates and enhancements on Energy 2020 used for load forecasting; continued refinement on the Regional Portfolio Model used for portfolio cost analysis; and updating the AURORA model used for market price forecasts. The beta version of the redeveloped GENESYS model was delivered September 2018. Testing of the model is scheduled for most of 2019. The redeveloped GENESYS model will use a detailed view of the hydroelectric system to reflect hourly operations (ANYLS-23).

While work on each of these models is ongoing, substantial progress has been made since the Seventh Plan. The Council has reviewed enhancements made to the load forecast and electricity market price forecast. More detailed review of the Regional Portfolio Model will be taken up in 2019 as part of the 2021 Power Plan process.

Transmission

Related Action Items: ANLYS-24, ANLYS-25

The Council continues to be engaged in transmission planning through the Reliability Assessment Committee (RAC), formerly known as the Transmission Expansion Planning Policy Committee (TEPPC, ANLYS-25), and regularly participates in planning work with staff from Columbia Grid, the Northern Tier Transmission Group (NTTG), and other entities, including the CAISO (ANLYS-24). The Council provides generating resource data for Northwest resources and reviews and provides feedback on dispatch results from models that simulate the entire Western U.S., including the

Northwest. This engagement shares understanding and improves the datasets that form the foundation of the modeling tools used by the Council and most planners and technical stakeholders in the region and across the Western U.S.

Fish and Wildlife

Related Action Items: ANLYS-20, F&W-1

The Council continues to monitor all current and proposed federal and state regulations regarding the impacts of generating resources on the environment and impacts to the regional power system (ANLYS-20). The Seventh Power Plan described a way for the region to discuss the cumulative effects of new resource development on wildlife and the environment. Engagement on studying these effects has been limited (F&W-1). There has not been interest in pursuing this issue in the way described in the Seventh Plan. Without that engagement, progress on this topic will be limited for the next power plan.

As part of the Fish and Wildlife Program’s 2017 wildlife project review, Council fish and wildlife staff met regularly with representatives of state agencies, Indian tribes, the U.S. Fish and Wildlife Service, the Bonneville Power Administration, and others to discuss the status of ongoing wildlife projects and mitigation issues. The concerns addressed by this action item did not come up in that context.

SECTION 3:
MARKET AND DEMAND COMPARISON AND UPDATE

Contents

List of Tables and Figures

REVIEW OF ECONOMIC DRIVERS

The Council uses several economic indicators and drivers to develop its power plan. Key forecasts include: regional population, the number of new homes and commercial buildings, and anticipated industrial output. Below is an overview of projected changes to these key drivers and their impact on regional energy demand.

The Council analyzes both regional "load" and "demand" for electricity. While the terms are often used interchangeably, for forecasting, they are distinct. "Load" is measured at the generator bus-bar and is a measure of the requirements put on the serving utility. "Demand" is the electricity used by the end-use customer. The difference between "load" and "demand" is transmission and distribution losses between point of generation and point of demand.

Population

One of the key drivers of demand for energy is growth in population.

In the Seventh Plan, population of the four states was projected to reach 16.4 million people by 2035. In the midterm assessment, the forecast is for the population to reach more than 16.7 million people; an increase of more than 300,000 people beyond what was anticipated in the Seventh Power Plan.

Residential sector

The midterm forecast of new residential units is higher than that in the Seventh Plan. Between 2016 and 2035 the region is expected to add 981,000 single family, 536,000 multifamily, and about 46,000 manufactured homes.

Table 3 - 1: Additional Homes (1000) 2016 - 2035

Homes	Midterm	Seventh Plan
Single Family	981	976
Multifamily	536	502
Manufactured	46	40

Commercial sector

The skyline of major metropolitan areas has seen the return of the massive construction crane. Preliminary estimates show that during the next 20 years, commercial floorspace will increase from 3.47 billion square feet in 2016 to more than 4.3 billion square feet by 2035. These projections are higher than the Seventh Power Plan's estimated new floor space additions by about 58 million square feet or about 1.3 percent.

Industrial Sector

Sectoral shifts from resource-based to technology-based industries continue. But industrial production (or value added) is projected to stay rather flat.

Table 3 - 2: Economic Drivers Growth Rates (2015-2035) by Forecast

Sector	Midterm	Seventh Plan
Residential	1.21 %	1.19 %
Commercial	1.41 %	1.20 %
Industrial	0.70 %	1.06 %
Agriculture	1.02 %	0.81 %

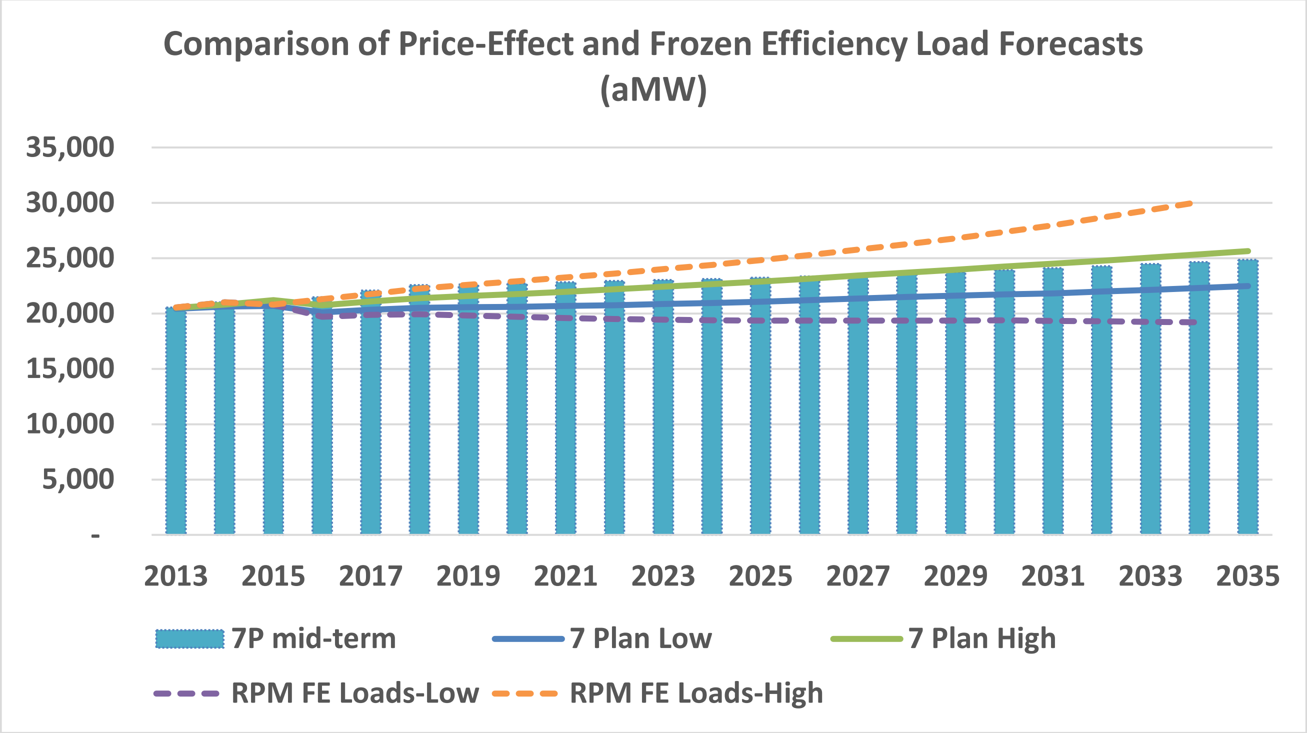
ELECTRICITY LOAD FORECAST

Although the regional economy has been growing, regional demand for electricity has been flat. Demand for electricity is measured at the consumer site or what is referred to as “behind the meter.” Preliminary data for 2017 suggests that since 2015 demand for electricity has been growing at an average annual rate of 0.7 percent. Most of the growth has been in the residential sector; there demand increased by about 4 percent from 2015 levels. This higher-than-expected growth in residential demand for electricity is due to the cold weather event the region experienced during the winter of 2017. Commercial sector demand growth was more modest at 1.3 percent. Industrial customers saw a decline in the demand for electricity with industrial demand declining by more than 4 percent between 2015 and 2017.

Regional load growth has been rather modest at 1.3 percent per year for the years 2015-2017. However, once the impact of temperature on load is removed, regional loads show an annual decline of 0.8 percent for the same period. Load is measured at the generator bus-bar; the difference between demand and load is transmission and distribution losses.

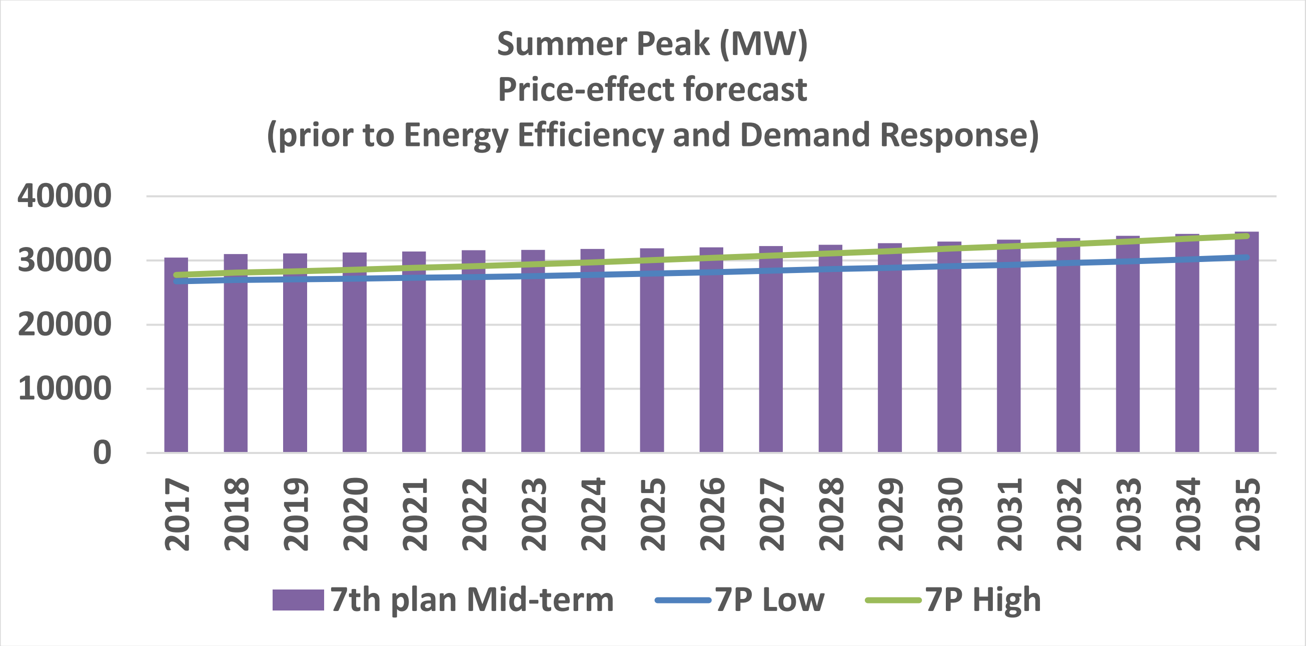
The three following graphs reflect the impact of changes in economic conditions for the forecast period. The midterm assessment load forecast is slightly above the Seventh Plan high forecast in the medium term (through 2027), but in the long-term it is within the Seventh Plan forecast range. Comparing the price effect forecast (that includes customer choices based on prices) from the midterm forecast and frozen efficiency that was used for development of the Seventh Plan, the midterm forecast is well within the load range used in RPM. Data for 2013-2016 show actual loads.

Figure 3 - 1: Load Forecast



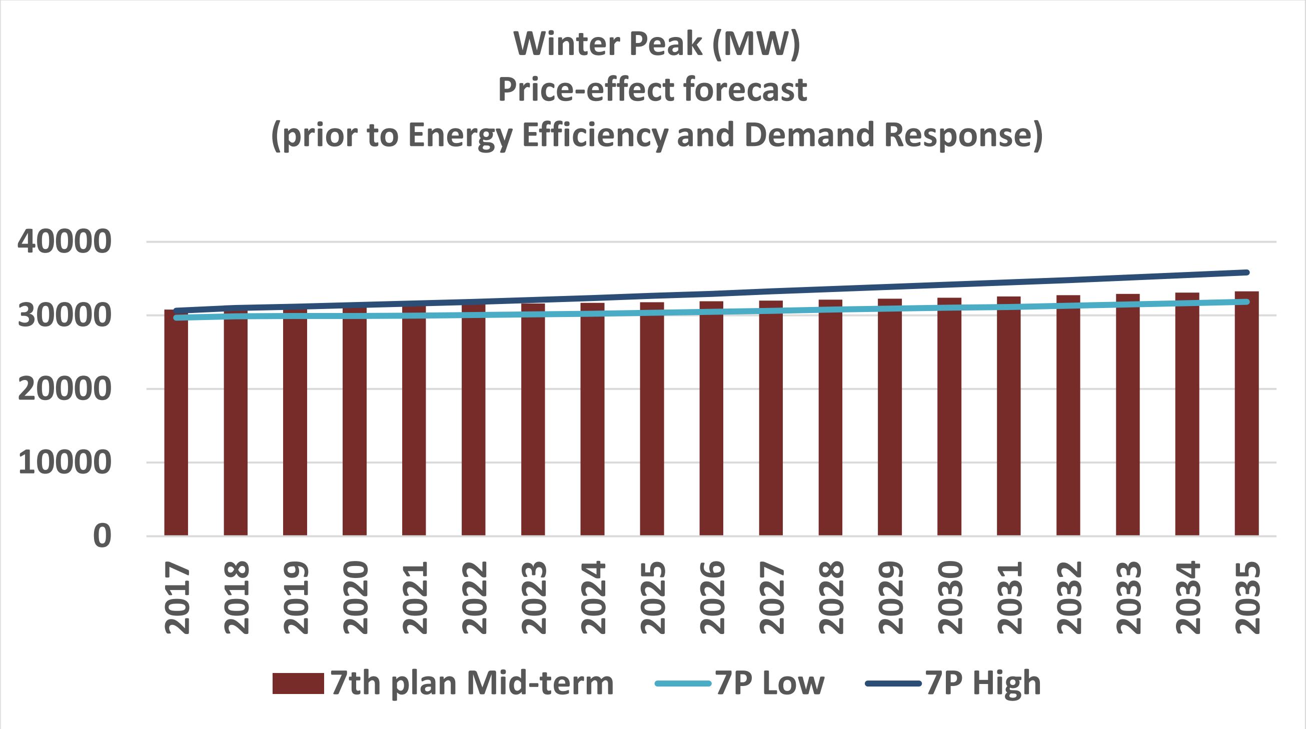
The midterm assessment forecasts higher summer peaks, than the Seventh Plan forecast. This higher forecast is due to a higher growth rate in the residential sector and a better modeling relationship between summer temperatures and loads. The Seventh Plan analyzed on an annual basis the relationship between cooling requirements and load. The midterm assessment analyzes the cooling requirements and load on a monthly basis. The two following graphs compare seasonal peak load forecasts from the Seventh Plan and midterm assessment for the price-effect forecast, which does not net out energy efficiency and demand response.

Figure 3 - 2: Summer Peak Load Forecast



The winter peak forecast from the midterm assessment is well within the range of forecast from the Seventh Plan.

Figure 3 - 3: Winter Peak Load Forecast



A cautionary note is needed here: the load forecast shown above is subject to change when data on the equipment saturation rate, market share of gas and electric appliances, and device efficiencies are updated for development of the 2021 Power Plan. The Residential Building Stock Assessment and Commercial Building Stock Assessment surveys are expected to become available for the next power plan but were not available for this midterm assessment.

Between 2015 and 2017, regional electricity retail rates increased modestly. On average (weighted average over all sectors) the retail rate increased from $80 to $84 dollars per MWh. Retail rates for residential customers grew from $98 to $101 dollars per MWh. Residential annual electric bills increased from about $1100 dollars to about $1185 dollars. Commercial sector customers saw a small increase in their average electric rate, from $85 in 2015 to $87 dollars in 2017. Industrial customer saw their rates increase from $52 per MWh in 2015 to $54 per MWh by 2017.

NATURAL GAS PRICE FORECAST

Background

Natural gas provides a key source of energy for the Northwest. Gas is used directly in homes and businesses as a fuel for space and water heating and is an important fuel for many large- and small-scale industrial processes. In addition, natural gas-fired power generators provide baseload electricity, peaking capacity, and help to integrate renewable wind power into the grid. As a result, natural gas prices exert a strong influence on the region’s wholesale electricity prices.

Gas is piped into the region from two primary sources: The Western Canadian Sedimentary Basin (WCSB) and the US Rockies region. The Northwest has a robust natural gas infrastructure build out, including multiple long-haul pipelines, above ground and underground gas storage facilities, and modern distribution systems.

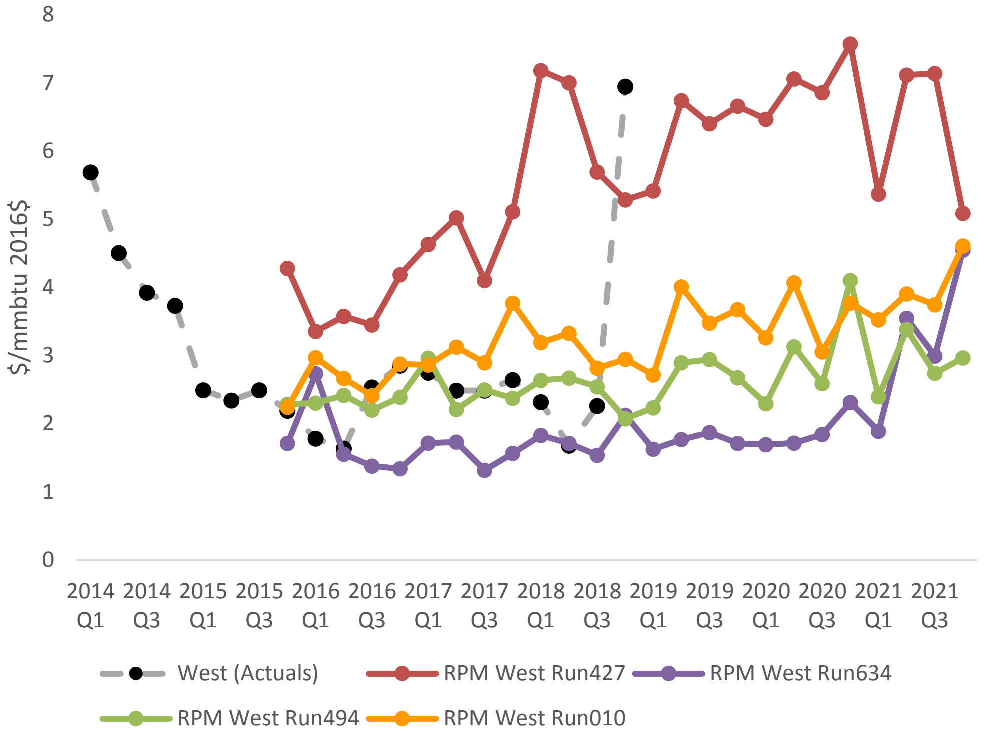
For the Seventh Plan, the final natural gas price forecast was developed in the fall of 2015. Prices had dropped significantly from the Sixth Power Plan as a result from the shale boom that swept across North America. An update to the natural gas price forecast was developed in late 2017 for the midterm assessment and was compared to the Seventh Plan forecast.

Methodology

Every two years the Council publishes a long term, natural gas price forecast that includes a medium, low, and high price view for Henry Hub, as well as for key regional gas hubs. The Council’s price forecast is developed from a combination of quantitative and qualitative analysis, and is directly influenced by input from the Natural Gas Advisory Committee (NGAC). Committee members are surveyed for their views on future natural gas prices. These inputs are used to construct a long term forecast of prices for the national pricing hub - Henry Hub. Analysis of historic price differentials between regional gas hubs and Henry Hub is used to generate price forecasts for the regional pricing hubs Sumas, AECO, and Opal.

Natural gas price volatility is also factored into in the Council’s planning process. The long term price forecast is combined with historic price volatility to generate 800 potential gas prices futures for consideration in the Regional Portfolio Model (RPM). The volatility contained in the price futures may represent real world events such as unexpected demand spikes, or regional supply disruptions like the natural gas pipeline rupture near Prince George, British Columbia, in October of 2018 which caused weeks of high gas prices at the Sumas hub. Since the Seventh Plan was published, there has been three years of historic natural gas prices that may be compared to the price futures used in the plan. So far the Seventh Plan forecast has managed to capture the actual price volatility. Figure 3-4 shows a sample of near-term RPM natural gas price futures in relation to recent actual prices. The price spike related to the recent pipeline rupture is easily visible in 2018 Q4.

Figure 3 - 4: Seventh Plan Natural Gas Price Futures and Actuals for the West Side

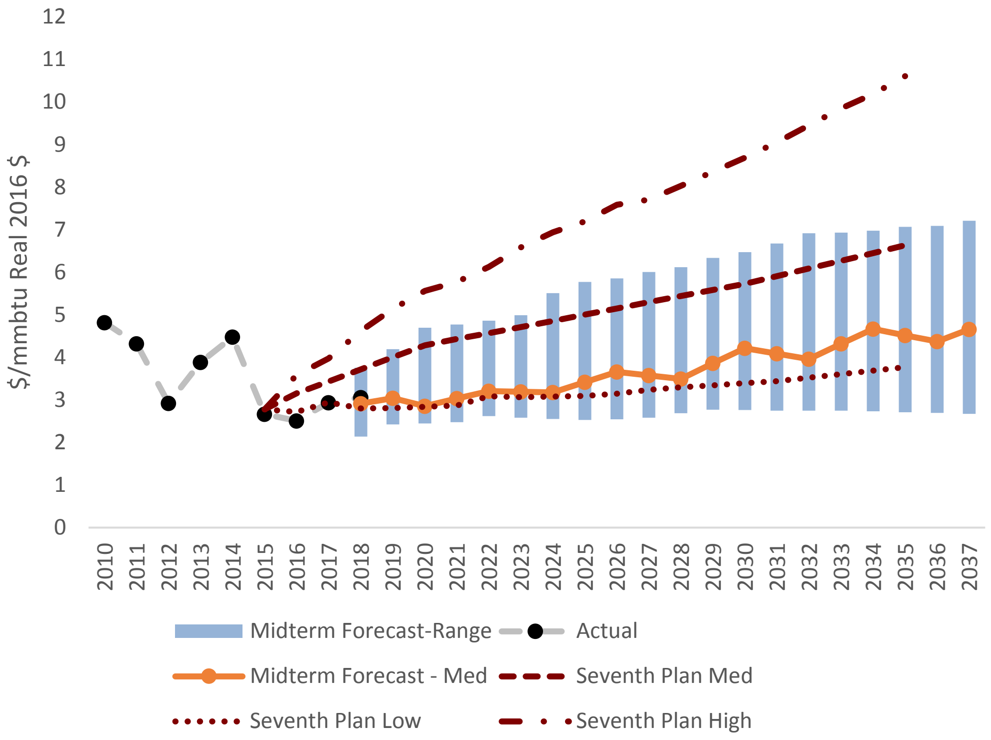


Update

With advances in technology and technique (hydraulic fracturing of shale and horizontal drilling), natural gas production in the US is at an all-time high. The primary growth driver for domestic demand is the power generation sector. Natural gas exports to Mexico via pipeline and Liquefied Natural gas (LNG), and LNG exports to Asia and Europe are a more recent source of demand growth.

The Natural Gas Advisory Committee (NGAC) met in the fall of 2017 and an update to the natural gas price forecast was developed. Natural gas prices are expected to remain relatively low and stable in the Northwest during the next three to five years because of an abundant and diverse supply. The updated natural gas price forecast for Henry Hub, along with recent actual prices and the Seventh Plan forecast is shown in Figure 3-5.

Figure 3 - 5: Annual Natural Gas Prices at Henry Hub



Actual prices from 2016 through 2018 at Henry Hub have been mostly following the low range of the Seventh Plan Forecast. The updated medium forecast (orange) falls within the Seventh Plan forecast range, while the low range has been reset to a lower level.

Prices have recently increased at the Sumas hub on the Washington-British Columbia border due to the supply disruption from the October 2018 pipeline rupture (Figure 3-6). At the Opal hub (Wyoming), gas prices have remained relatively stable (Figure 3-7).

Figure 3 – 6: Annual Natural Gas Prices at the Sumas Hub

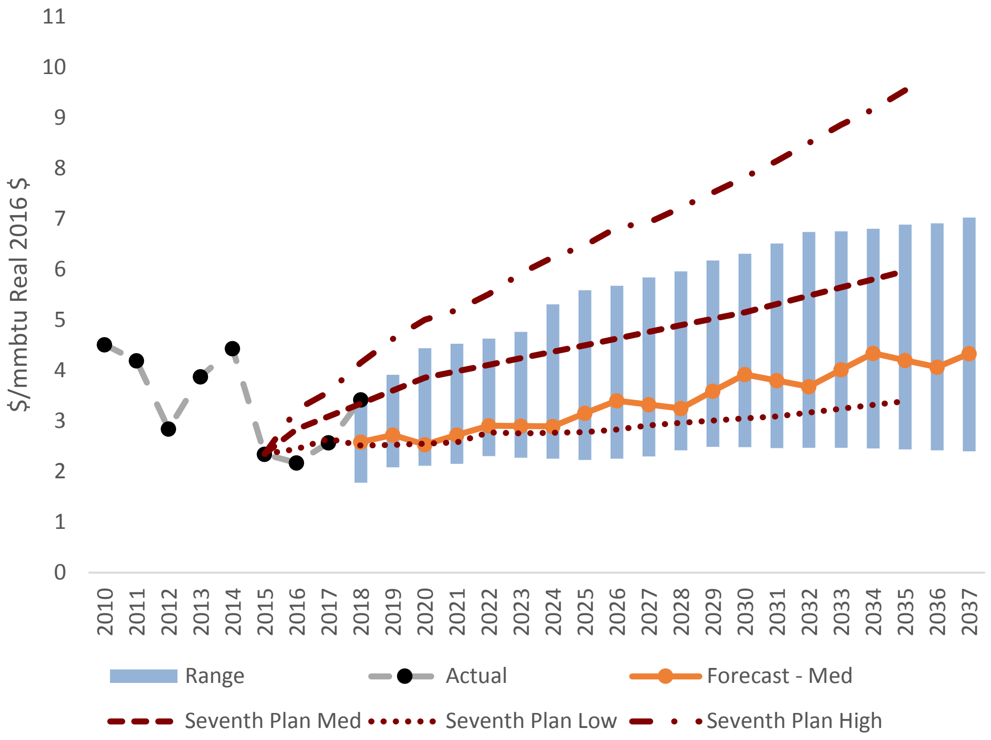
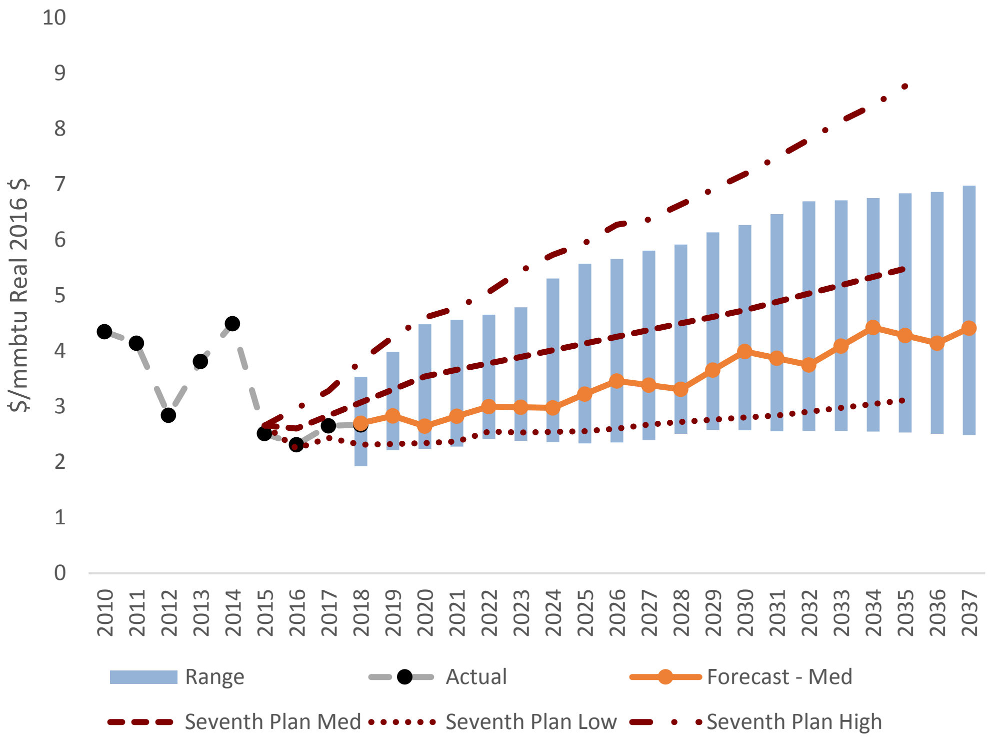
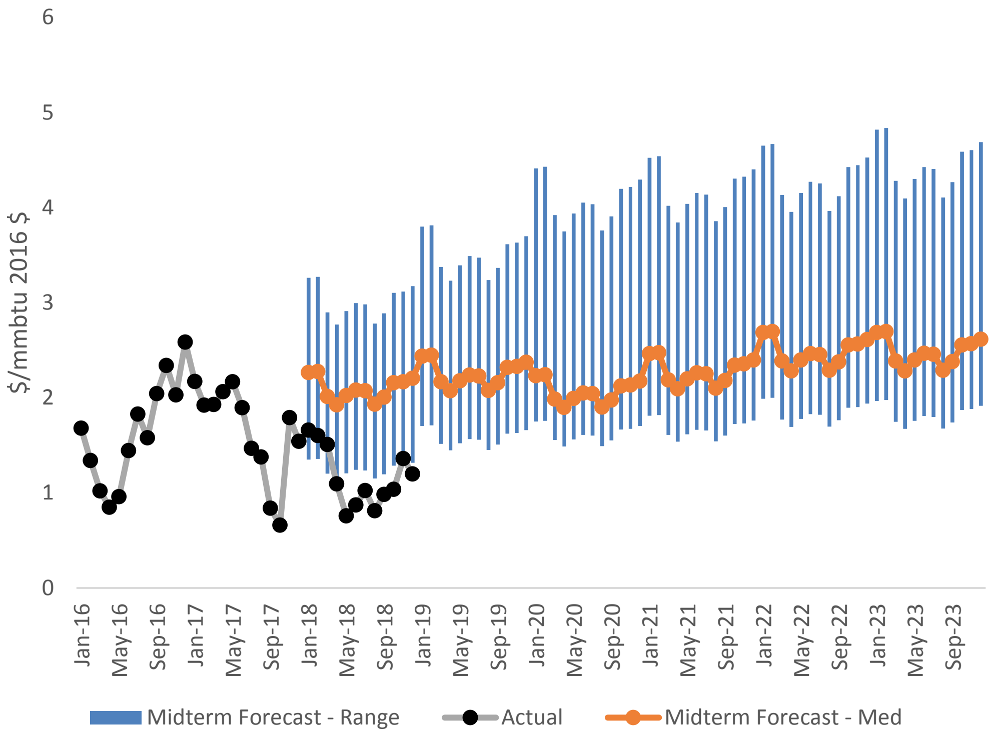


Figure 3 – 7: Annual Natural Gas Prices at the Opal Hub



As in the US, natural gas production is also booming in Canada (Alberta, British Columbia); an important source of gas for the Northwest. Recently, gas prices in Alberta have at been historically low levels and are bouncing along the low range of the updated Council forecast (see Figure 3-8). In the near term, prices have been low due to pipeline maintenance issues and oversupply. Should demand pick up from growth in gas-fired power generation in Alberta and development of Western Canadian LNG export terminals, this extremely low-price environment could change.

Figure 3 - 8: Monthly Natural Gas Prices at AECO



WHOLESALE ELECTRICITY PRICE FORECAST

Background and Methodology

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices. The AURORA[1] model dispatches all resources in the Western Electricity Coordinating Council (WECC) generating a fundamentals-based wholesale electricity price forecast. The electric grid[2] as currently modeled in the Council's AURORA setup is represented by 46 zones[3] connected by

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[1] The AURORA electricity price model is licensed from EPIS/Energy Exemplar.

[2] West Interconnect topology

[3] Each zone can represent a set of electric demands, and demand-side and/or generating resources.

associated transmission capabilities that represent a simplified version of the transmission system connecting balancing authorities in the Western US.

The 2019 through 2038 price forecast includes generating resource capacity and retirement updates for resources external to the region[4] and updates from the regional generating resource database for resources internal to the region. Additionally, natural gas prices and loads (as presented in the prior section), state Renewable Portfolio Standard (RPS) requirements, and fixed costs for new generating resources (see Section 6) were updated since the Seventh Power Plan electricity price runs. The buildout of new resources in the region throughout the 20-year forecast are consistent with Seventh Power Plan conservation target and demand response recommendations, and after 2026 consistent with buildout to meet the Council's adequacy standard.[5]

This price forecast includes the following scenarios representing uncertainty in natural gas price, load, and carbon policy:

1. Existing Policy Medium - medium forecasts for regional electricity load and WECC fuel prices
2. Existing Policy High Demand - high regional load forecast, medium fuel price
3. Existing Policy Low Demand - low regional load forecast, medium fuel price
4. Existing Policy High Fuel - high fuel-price forecast, medium load forecast
5. Existing Policy Low Fuel - low fuel-price forecast, medium load forecast
6. Social Cost of Carbon Medium - medium forecasts for regional load and fuel price, using mid-range social cost of carbon pricing consistent with the scenario in the Seventh Power Plan

Additionally, the Existing Policy Medium scenario was simulated under 80 hydro conditions (1929-2008). The price risk due to change in hydro runoff was tested in the other scenarios by simulating the low (1931, 1937, 2001), medium (1960, 1990, 2000) and high (1974,1996,1997) hydro conditions.[6] Since the AURORA model has limited functionality in representing the complexity of the constraints associated with the regional hydro system, hourly maximum and minimums and monthly hydro energy budgets are derived from the GENESYS model to limit the AURORA dispatch of the Northwest hydropower system.[7]

Summary of Key Findings

The primary finding for the midterm is, over the breadth of price forecast scenarios, the wholesale electricity price falls within the band of prices used to evaluate resources for the Seventh Plan. While

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[4] Per the WECC 2026 Common Case dataset.

[5] A regional planning reserve margin of 13% is applied to the region after 2026 to maintain consistency with the 5% LOLP adequacy criteria for the region.

[6] Determined scenario classification of low, medium and high by checking historical average flow into The Dalles during the runoff period and confirmed choices with System Analysis Advisory Committee.

[7] If some sort of limitation is not applied to AURORA hydro dispatch, the model sees hydro as a big, cheap battery and prices in the WECC reflect an unrealistic hydro operation.

the prices trend lower on average due to an even lower gas price forecast, the range of wholesale prices forecasted are within the price forecast of the Seventh Plan. Other key findings are as follows:

1. Natural gas prices continue to be the best indicator of the wholesale electricity price forecast.
2. Monthly power prices in the Northwest are significantly influenced by hydro conditions.
3. As the WECC becomes more reliant on natural gas and renewable energy, especially solar, the daily price shape increases in volatility.

For the existing policy scenario, the expected wholesale price of electricity[8] at the Mid-Columbia (Mid-C)[9] is expected to increase from about $23 per MWh in 2019 to just over $51 per MWh by 2038, representing a 4.35 percent annual price increase. Adjusted for inflation the annual price increase is about 2.21 percent.

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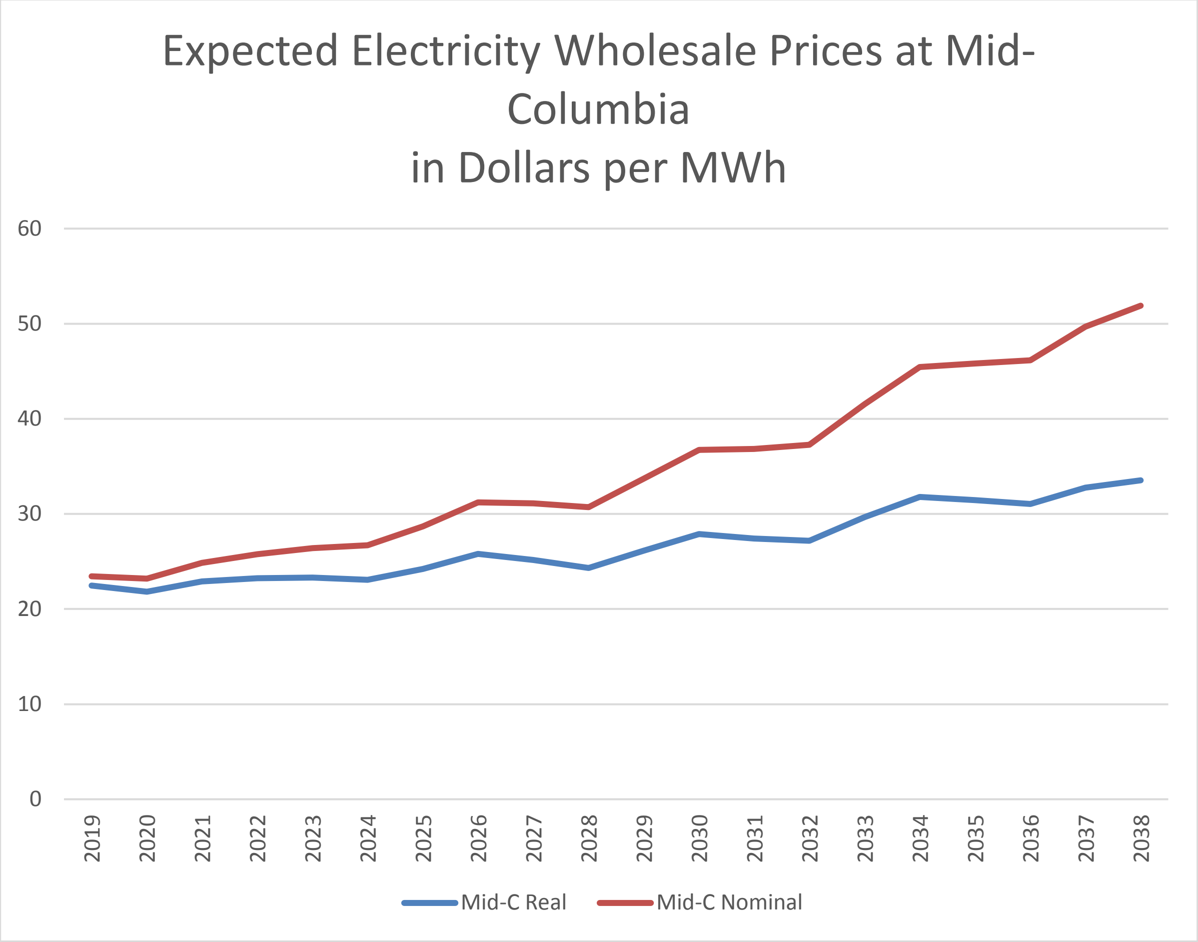
[8] Expectation calculated over the 80 simulations for the existing policy scenario.

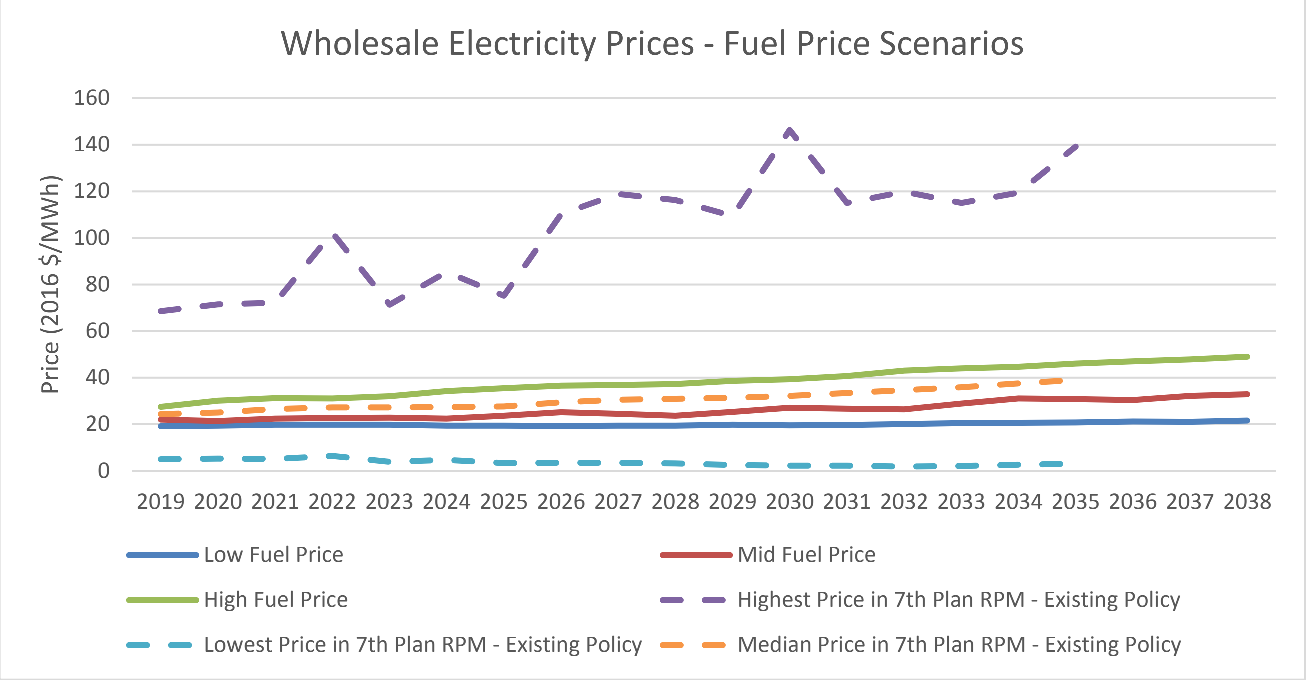
[9] Expected Mid-Columbia price over all 80 hydro conditions, medium fuel price, and load forecasts. Mid-Columbia price is approximated here by assessing the price of electricity at the BPA Washington zone in the West Interconnect topology of AURORA.

Figure 3 - 6: Annual Wholesale Electricity Price Forecast from 2019 to 2038



The most influential underlying factor determining annual wholesale electricity prices continues to be natural gas prices. Per Figure 3 – 7, power prices vary by plus or minus $5 per megawatt-hour at the beginning of the study depending on the gas price forecast, but by the end of the study they vary by plus or minus $15 per megawatt-hour.

Figure 3 - 7: Annual Wholesale Electricity Prices Under Different Natural Gas Price Forecasts



Prices are also heavily influenced by the hydro conditions in the Columbia River watershed and thus, are highly seasonal. During the spring runoff period market prices tend to be low, but as can be seen in in Figure 3 – 8, there is significant variability in the timing and volume of the runoff. Between December and August, these differences in runoff create a significant price variation depending on the hydro condition.[10]

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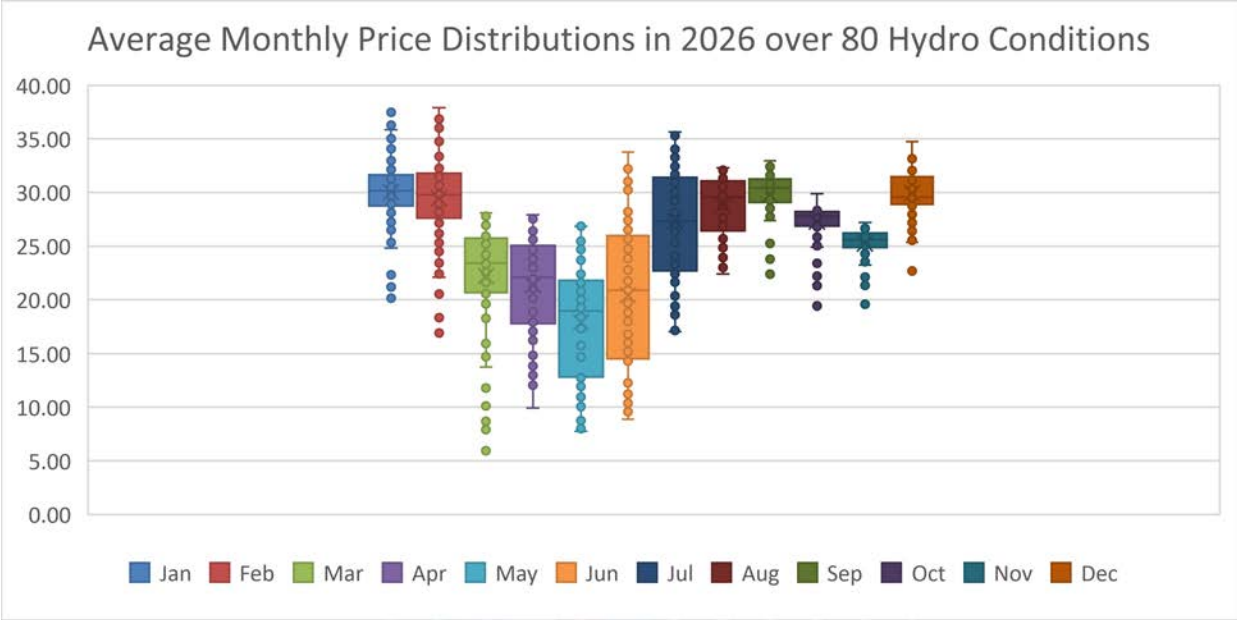
[10] The “box and whiskers” chart shows the distribution of average monthly prices over all the hydro conditions. The median, 50th percentile of the distribution, is represented as the x inside the box. The mean of the distribution is represented as the line inside the box. The boundaries of the first and third quartiles, 25th and 75th percentiles of the distribution, are represented as by the bottom and top boundaries of the box. The “whiskers” bound the distribution and represent the minimum and maximum data values.

Figure 3 - 8: Monthly Wholesale Power Prices in 2026 by Hydro Condition Year



Hydro conditions and renewable resource availability, particularly solar, drive variation in the daily price shape. Per Figure 3 - 9, the daily price shape in the winter, spring and fall reflects predominantly dual peaking (morning and evening) behavior, but in late spring through fall the peak prices occur primarily during the evening hours. Notice that during all times of the year, the large amount of solar power from the Southwest U.S. depresses prices in the middle of the day. This effect, often referred to as “the duck curve” reflects the response of higher priced resources being brought on-line when the solar generation is decreasing with the setting sun. Winter and spring daily price shapes are most influenced by different hydro conditions, whereas summer and fall show less price variability except during peak hours.

This daily price shape dynamic changes over the planning horizon depending whether wind or solar are chosen to meet increased renewable resource build requirements[11] throughout the WECC, particularly in California.

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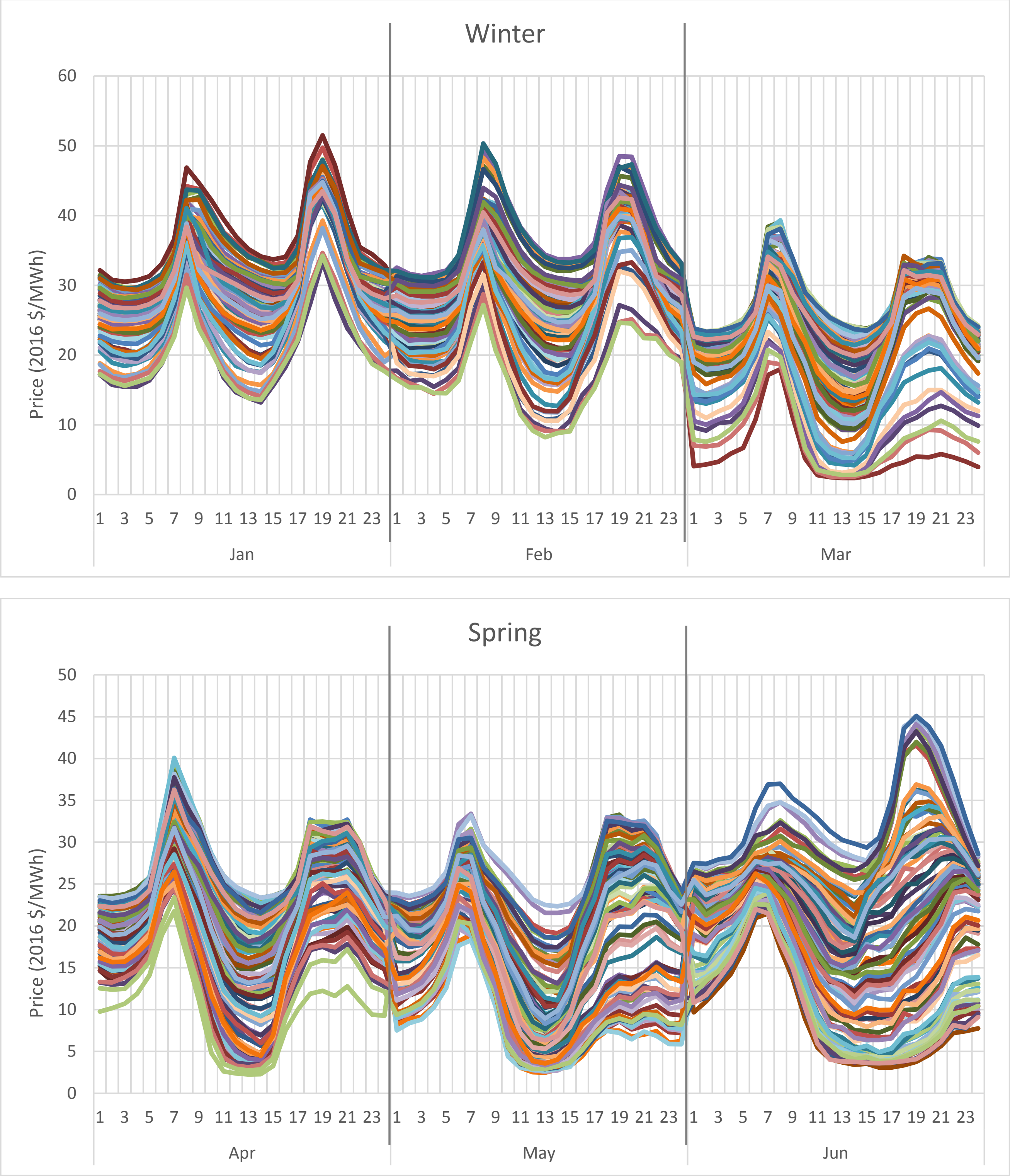
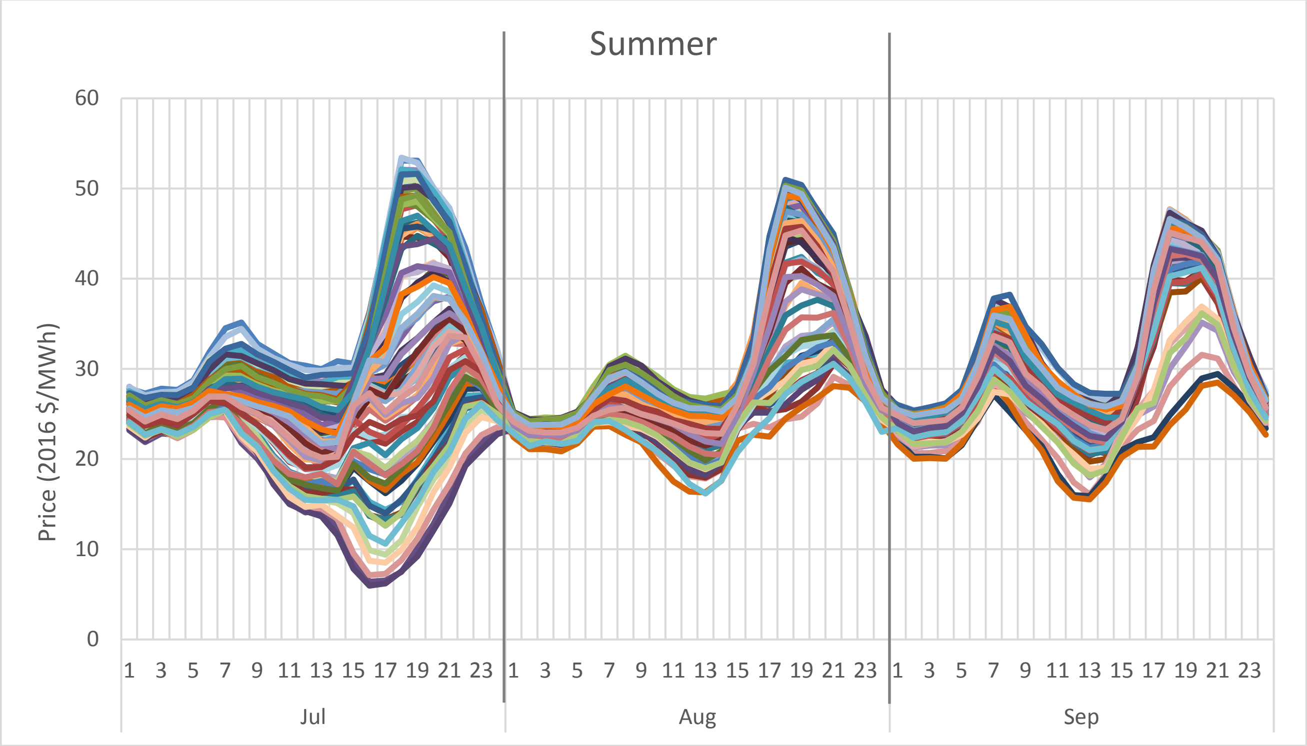
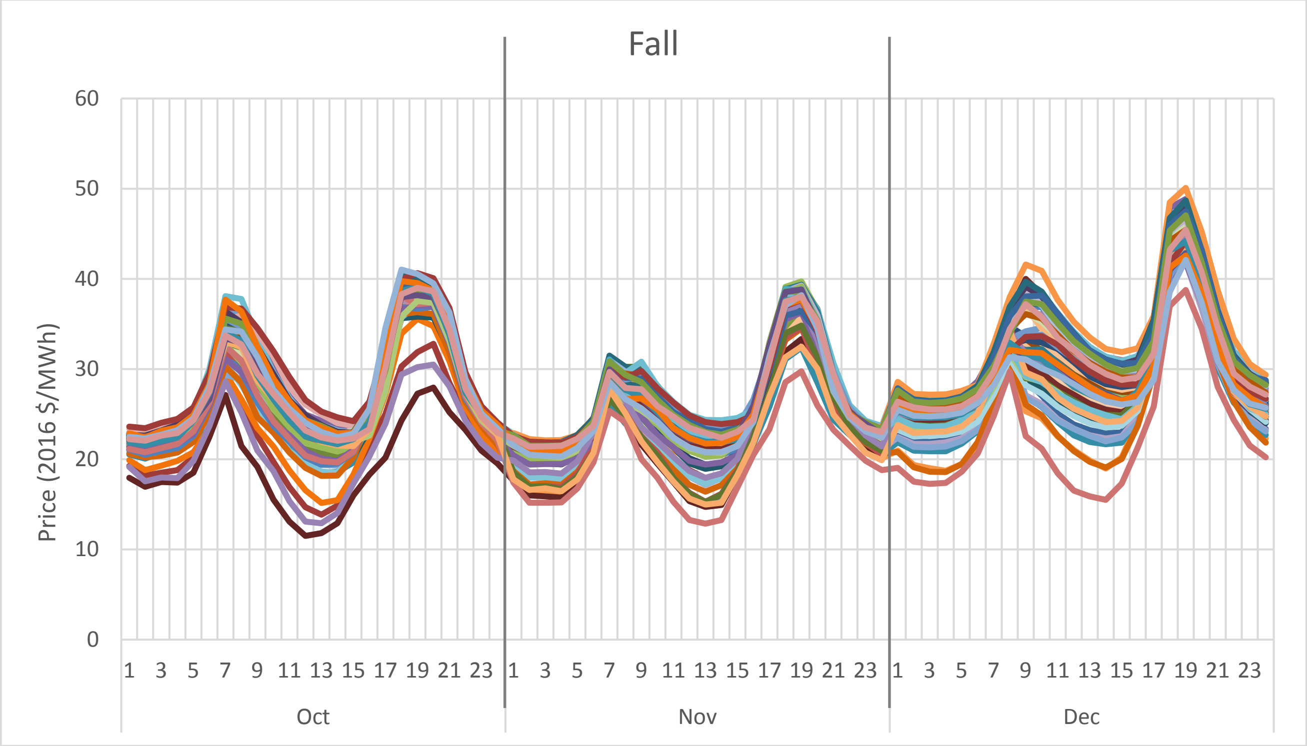
[11] Primarily to meet state Renewable Portfolio Standards.

Figure 3 - 9: Daily Wholesale Power Price Shape in 2026 by Month for 80 Hydro Conditions




Summer
Price (2016 $/MWh)
60
50
40
30
20
10
0
1 3 5 7 9 11 13 15 17 19 21 23
Jul
Aug
Sep


Fall
Price (2016 $/MWh)
60
50
40
30
20
10
0
1 3 5 7 9 11 13 15 17 19 21 23
Oct
Nov
Dec

SECTION 4: CONSERVATION

Contents

List of Tables and Figures

INTRODUCTION

The Seventh Power Plan called on the region to acquire 1,400 average megawatts of energy efficiency over the six-year action plan period (2016-2021). The Plan provided two-year milestones over the six-year period to reach this goal.

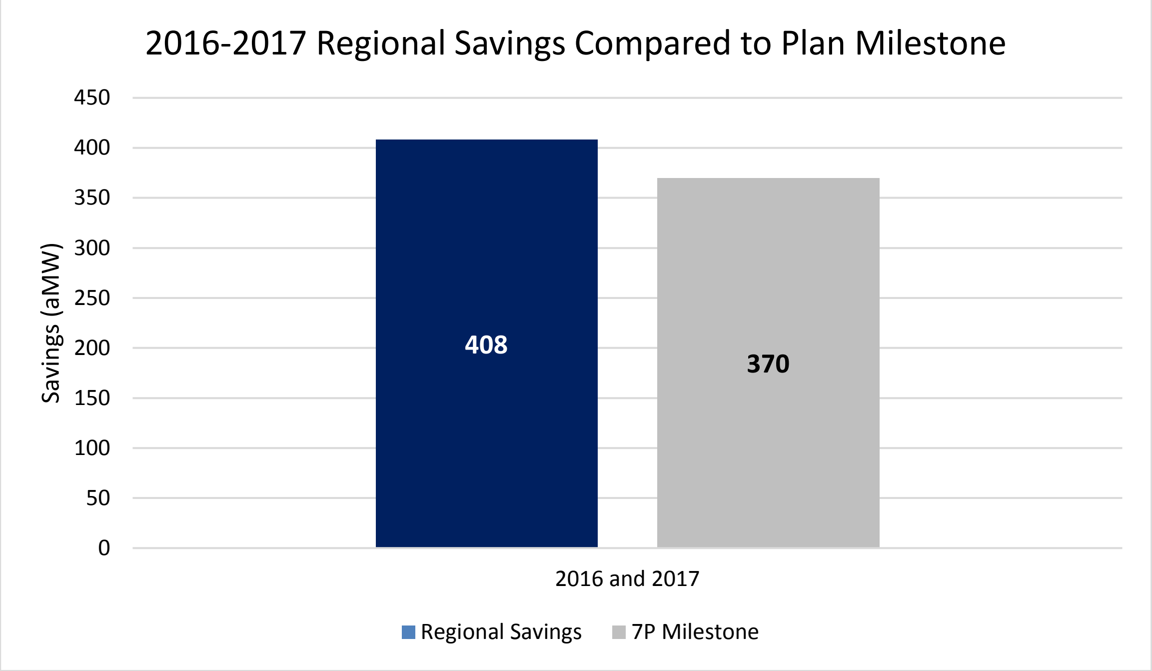
Table 4 - 1: Seventh Plan Six-Year Energy Efficiency Goal and Milestones

	2016-2017	2018-2019	2020-2021
Bi-Annual Energy (aMW)	370	460	570
Cumulative Energy (aMW)	370	830	1,400

Regional savings from energy efficiency come from a variety of sources, including direct utility and Energy Trust of Oregon program savings and those from long-term efforts to transform the markets, savings tracked by the Northwest Energy Efficiency Alliance (NEEA) for its initiatives, as well as codes and standards improvements, and other market changes. In its annual Regional Conservation Progress (RCP) survey, the Council seeks data on as many of these savings mechanisms as possible to understand the impact of energy efficiency on the regional power system and to appropriately plan for future resource acquisition.

In the recent RCP, the region surpassed the first two-year milestone of 370 average megawatts by achieving 408 average megawatts of energy efficiency.

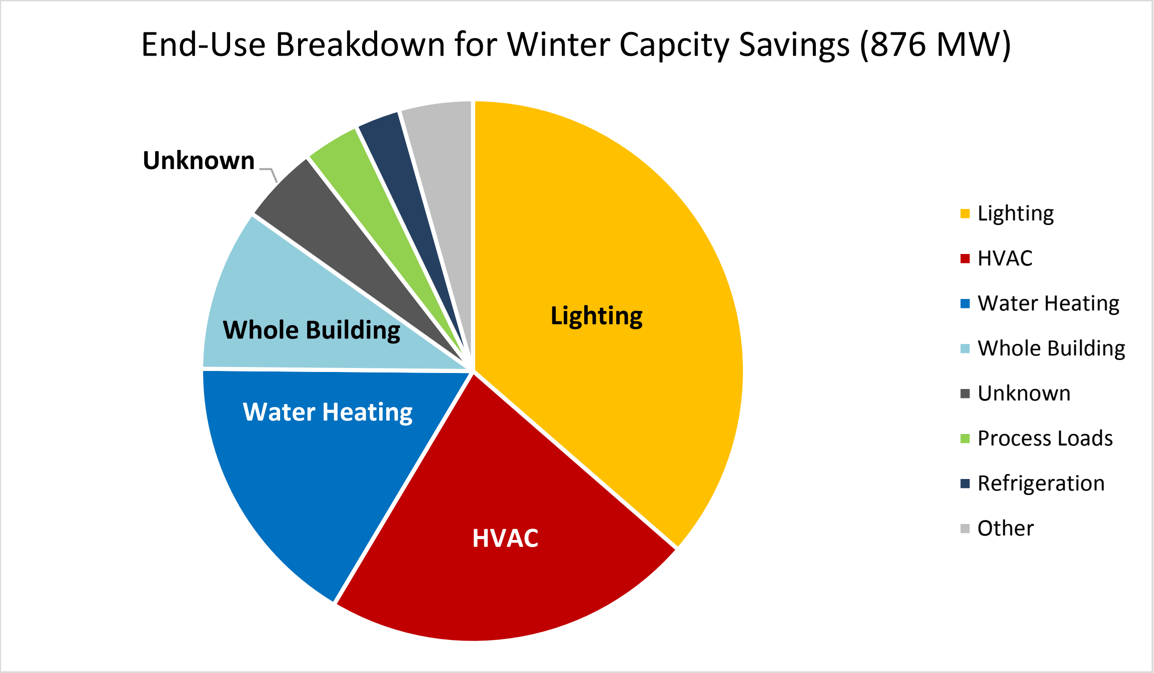
Figure 4 - 1: Regional Efficiency Achievements Compared to the First Two-Year Milestone



Consistent with the findings in the Seventh Plan, the region is seeing the capacity value of energy efficiency. Energy planners and efficiency program operators have begun to take the capacity contribution of energy efficiency into account. Many programs are now considering capacity value explicitly or trying to determine how best to incorporate capacity value into their energy efficiency programs. At the same time, a large coalition of regional utilities, the Bonneville Power Administration, and the Energy Trust of Oregon have committed funding for end use load research to improve understanding of capacity impacts.

The demonstrated capacity savings in 2016 and 2017 are significant. The 408 average megawatts of regional energy efficiency achievements correspond to about 876 megawatts of winter peak capacity reduction and 501 MW of summer peak reduction.[1] Figure 4-2 and Figure 4-3 show what end-uses are contributing most to both winter and summer capacity savings. Energy efficiency measures for lighting represent the most significant contribution to capacity savings in both winter and summer. Other end-uses tend to provide significant benefit in one season. For example, heating, ventilation, and air conditioning (HVAC) and water heating provide significant benefits in winter, whereas irrigation savings are concentrated in the summer.

Figure 4 - 2: 2016 and 2017 Winter Capacity Savings from Energy Efficiency



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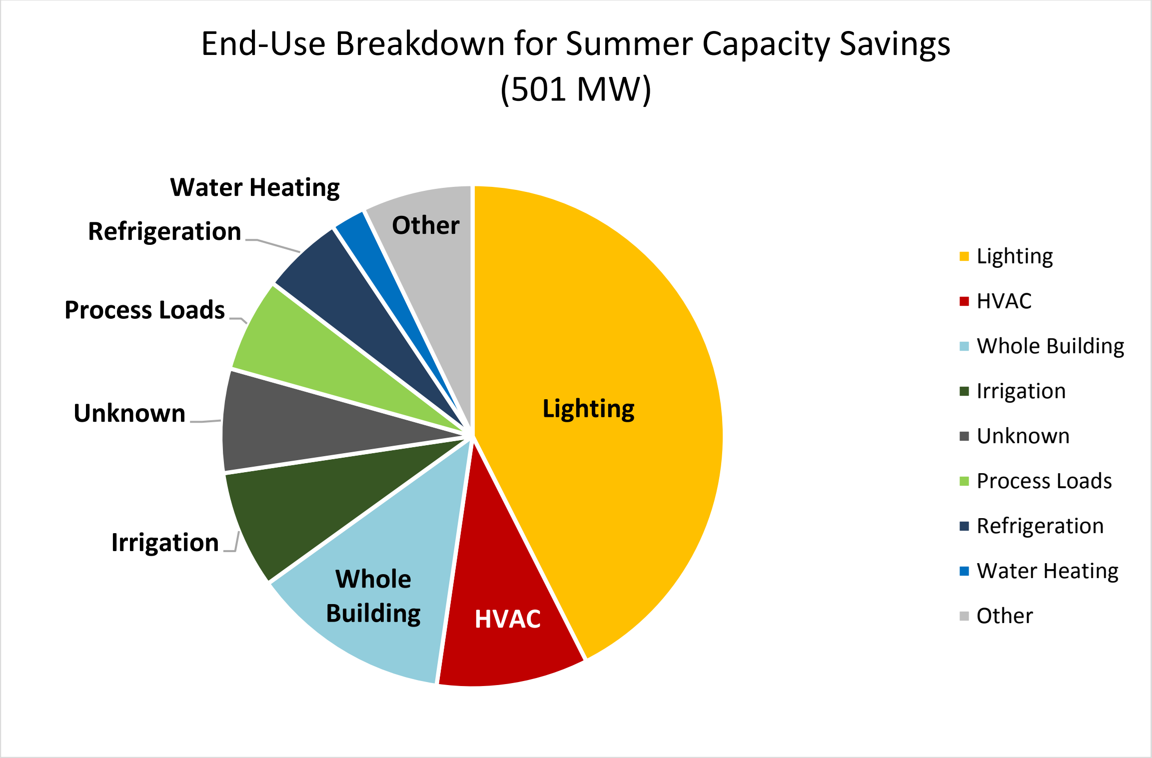
[1] The regional winter peak is defined as 6pm on a weekday in December, January, or February; summer peak is defined as 6pm on a weekday in July or August.

Figure 4 - 3: 2016 and 2017 Summer Capacity Savings from Energy Efficiency



The RCP summarizes utility plans for future energy efficiency programs and expenditures. The RCP found that despite success to date, based on what programs reported about anticipated expenditures going forward, there is a potential risk that the region will not meet the Council's six-year goal of 1,400 average megawatts of energy efficiency. The sections below provide detail on the different savings streams, which represent progress to date, projections for future savings, and areas of risk for the six-year goal.

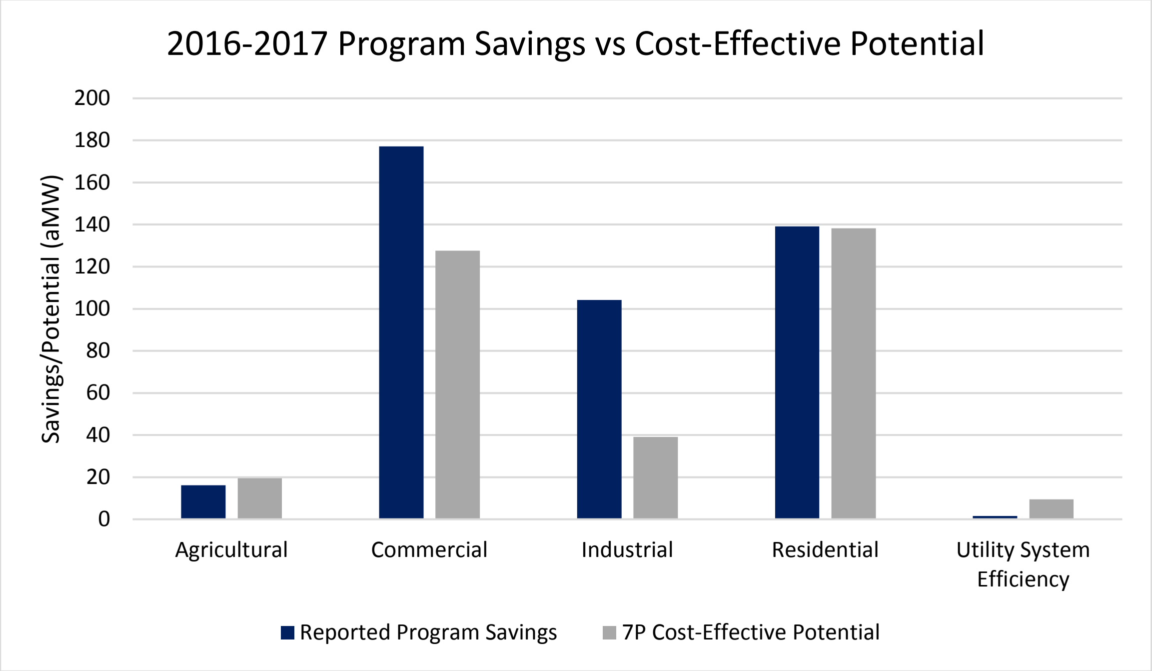
PROGRAM SAVINGS

Most of the region's acquisition of energy efficiency comes from targeted programs. The region's utilities, Energy Trust of Oregon, and the Bonneville Power Administration promote and incent cost-effective energy efficiency options to their customers, with a goal of influencing consumer choice toward energy efficiency. Program savings represent the utilities' accomplishments from these activities. In the RCP, the Council collected data on program savings for 2016 and 2017, as well as projections for 2018 and 2019.

2016 and 2017 Program Savings

During the two-year period, regional utility programs invested $981million in acquiring energy efficiency, resulting in significant savings. Figure 4-4 compares reported program savings to date relative to the cost-effective potential identified in the Seventh Plan for the same two-year period by sector. Programs appear to be relatively on track in the agricultural and residential sectors. On the other hand, programs are reporting more savings than the Seventh Plan estimated for cost-effective potential for the industrial and commercial sectors. This may be driven, in part, by custom efficiency projects in these sectors, requiring programs to estimate savings at an individual site based on the specific existing conditions of that site. Finally, utility system efficiency remains generally untapped by programs. Over the first two-years of the Plan, programs acquired roughly 16 percent of the cost-effective potential for these measures identified in the plan.[2]

Figure 4 - 4: Reported Program Savings Compared to Seventh Plan Cost-Effective Potential, by Sector, for 2016 and 2017



As shown, most program savings were in the commercial (40 percent) and residential sectors (32 percent). Figure 4-5 highlights where savings were acquired within each of these sectors. It also compares those reported savings against the cost-effective potential identified in the Plan for the same two-year period.

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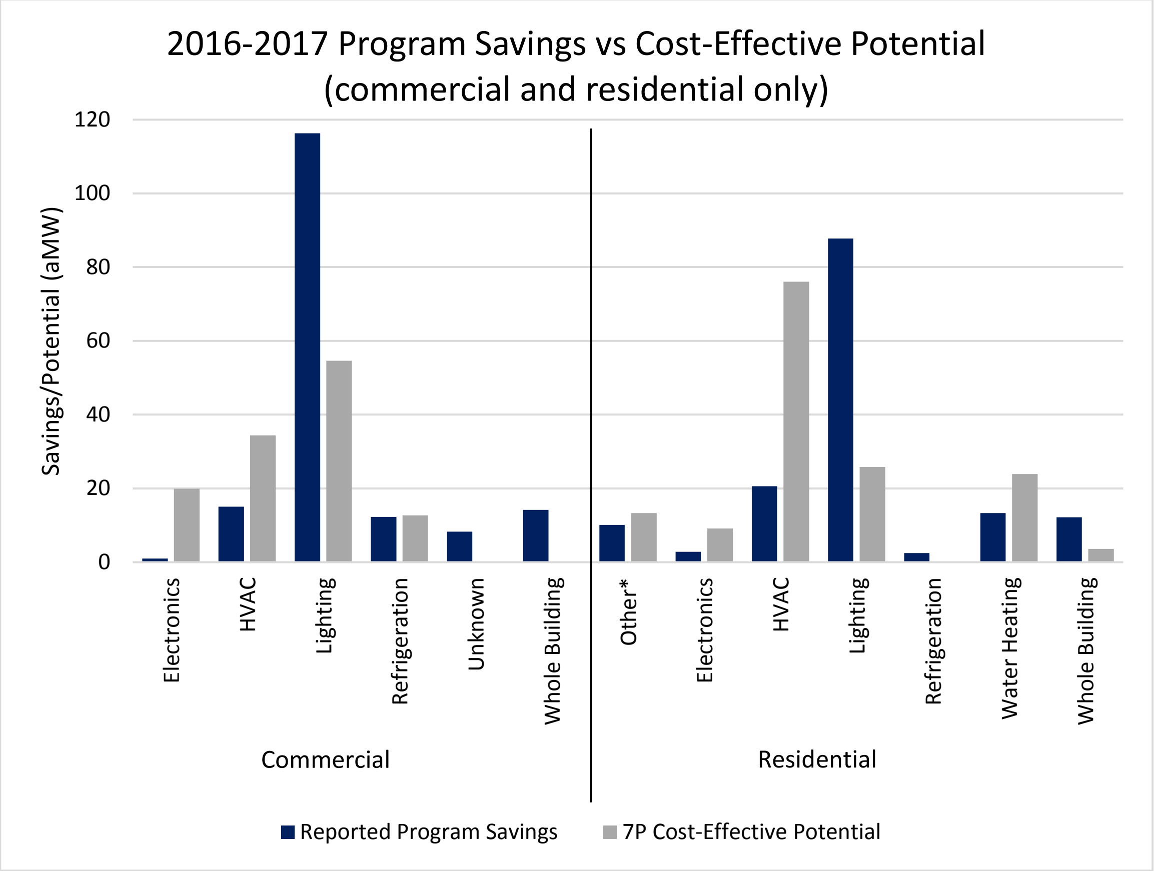
[2] For more information on the status of these efforts, see Chapter 2.

Figure 4 - 5: Reported Program Savings Compared to Seventh Plan Cost-Effective Potential, by End Use, for Residential and Commercial Sectors



*Commercial "other" includes: compressed air, motors/drives, process loads, food preparation, and water heating.

As shown, most of these savings (65 percent) come from efficient lighting products, which explains why lighting is such a significant contributor to capacity savings These accomplishments are not surprising, given that there is strong market interest in efficient lighting: it is relatively cheap to acquire and easy to implement compared to other efficiency resources. While there continue to be cost-effective opportunities for lighting, in order to meet the future goals for energy efficiency, programs will need to expand their focus and acquire resources from other end-uses that are generally more challenging and expensive to acquire. In particular, residential and commercial HVAC, residential water heating, and commercial electronics are end-uses that show significant, untapped, cost-effective potential. Savings from these end-uses tend to be challenging and more expensive to acquire. On the other hand, these end-uses also tend to provide a more significant winter capacity benefit compared to lighting.[3]

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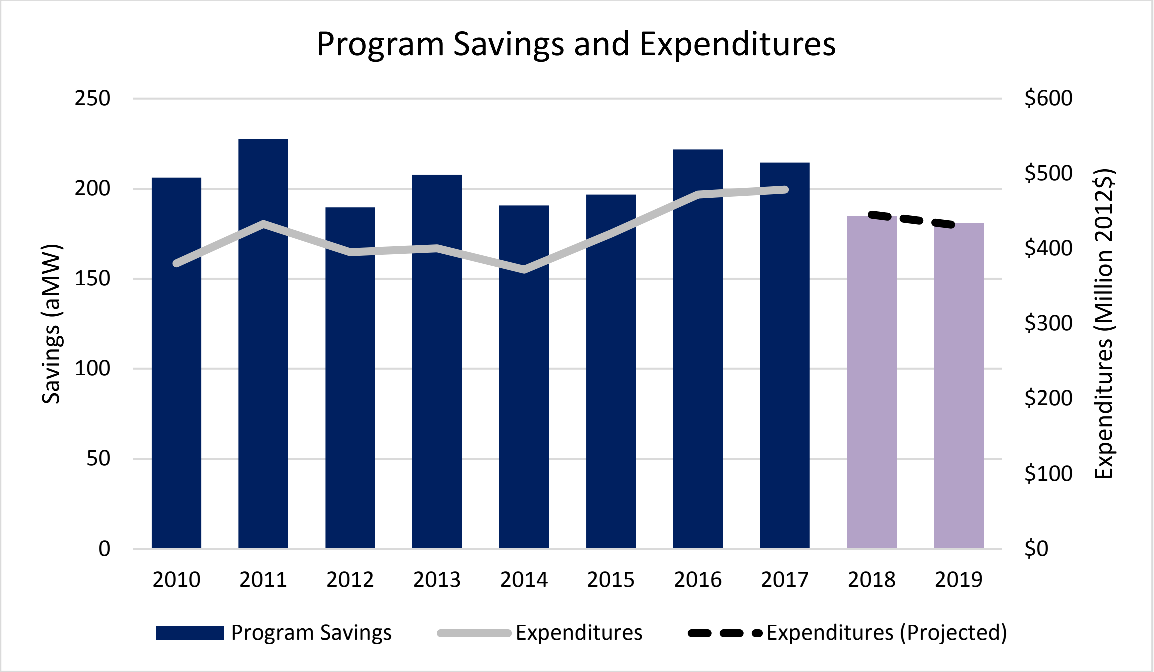
[3] As shown in Figure 4-2, HVAC and water heating represent almost 40 percent of the winter capacity benefit, despite only representing 14 percent of the regional energy savings

Projected Utility Program Activities

For the RCP, the Council collected data on projected utility efficiency activities. Based on the data provided to date, programs are generally projecting flat-to-declining budgets and savings over the 2018-2019 period. Figure 4-6 shows the claimed program savings and expenditures for 2010-2017 alongside projected savings and expenditures for 2018 and 2019. The Bonneville Power Administration's Energy Efficiency Incentive (EEI) program budget decreases by $6 million dollars (approximately 4 percent) in 2018 and 2019, compared to the 2016 and 2017 period. The agency expects its customer utilities to increase individual funding for energy-efficiency projects.

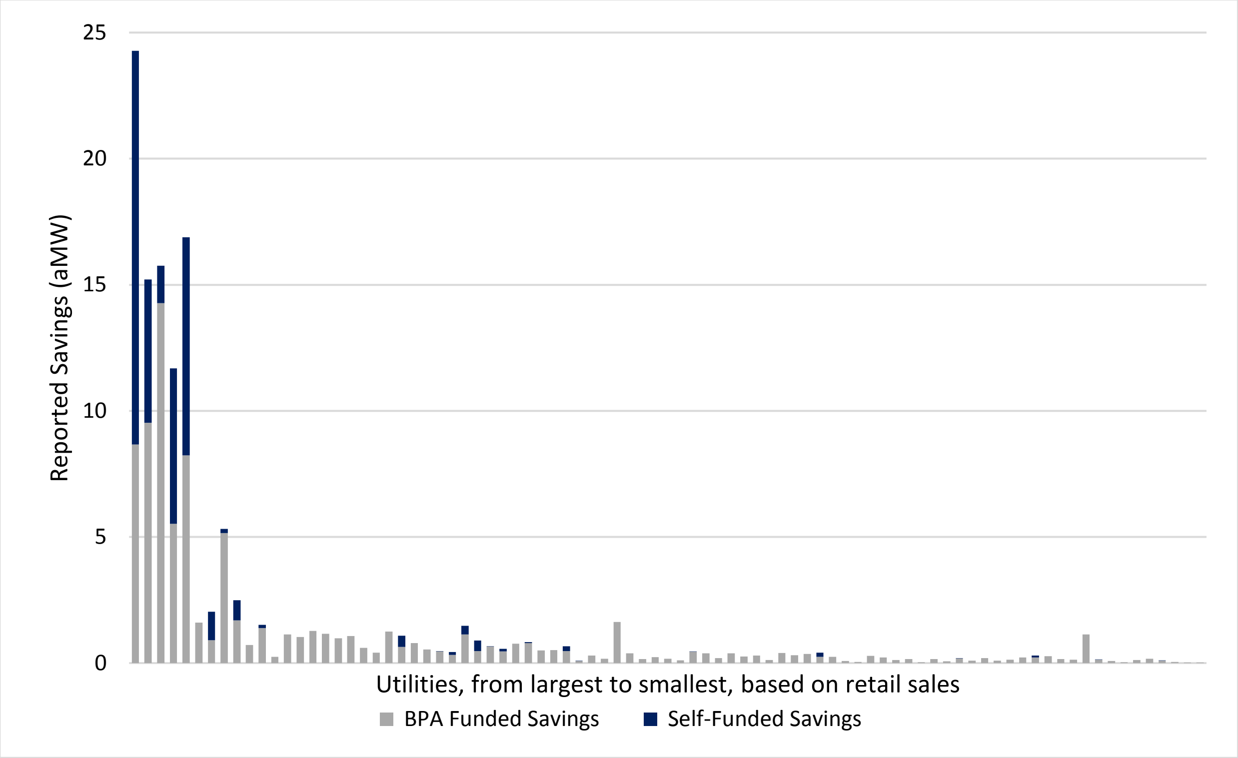
Figure 4 - 6: Reported Program Savings and Expenditures for 2010-2017 and Projected Savings and Expenditures for 2018 and 2019



As shown, program savings are closely tied to expenditures. When programs invest more in acquiring energy efficiency, they tend to achieve greater savings. The projections for 2018 and 2019 indicate that as budgets remain relatively flat, savings are expected to follow.

Within the Bonneville Power Administration system, program efficiency funding relies on a mix of EEI funds through Bonneville and the utilities' own budgets, or "self-funded" projects. For 2016-2017, the region's public utilities directly, or "self-funded" approximately 39 percent of the total. As shown in Figure 4-7, most of the self-funding is spent by the region's largest public utilities. These same utilities provide the majority of BPA's program savings. The five largest BPA customer utilities, which make up slightly less than half of the public utility load, contributed 65 percent of all BPA program savings. If their integrated resource plans continue to show potential, it is anticipated that these utilities will continue to contribute significantly to the Bonneville Power Administration savings.

Figure 4 - 7: BPA-Funded vs Self-Funded Reported Program Savings for 2016 and 2017



NEEA ALLIANCE SAVINGS

The Northwest Energy Efficiency Alliance (NEEA) is a regional organization focused on transforming markets toward greater efficiency. NEEA's value to the region comes from increased energy efficiency acquisition in the long-term and filling the pipeline for new savings by scanning for opportunities in emerging technologies and applications. When successful, these savings come in at a cheaper cost and rate than would have occurred without NEEA. For example, during the last two years, NEEA's scanning and emerging technology work has produced some promising new opportunities that have large savings potential as identified in the Seventh Power Plan. Two new initiatives were launched in 2018 for very high efficiency commercial HVAC systems and for motor drive pump systems for small applications. NEEA has also stepped up to facilitate collaborative regional work on emerging technologies. The Regional Emerging Technology Advisory Committee is now charged with optimizing regional investment in emerging energy-efficient technologies. Related to this work, NEEA and others are engaged with state code and federal standard setting organizations, providing data and analysis to inform future updates in both processes.

NEEA also tracks potential energy efficiency savings across an entire market for many products. That is, rather than just looking at the units coming through a utility program, they track all efficient products sold in the region. In reporting savings to the Council, NEEA estimates the total efficiency that occurred above the power plan baseline, subtracting out program savings to avoid double counting.

In 2016 and 2017, NEEA tracked and reported 63 average megawatts of NEEA Alliance savings. Most of these savings (70 percent) are in the residential lighting market, representing savings that were not captured in utility programs from efficient LED and CFL lamps. In addition to residential lighting, NEEA tracked savings for residential ductless heat pumps, heat pump water heaters, residential appliances, new construction, commercial building improvements, commercial electronics, and industrial refrigeration and motors. In 2018 and 2019, NEEA projects similar levels of Alliance savings with another 60 average megawatts targeted for acquisition.

NEW FEDERAL AND STATE CODES AND STANDARDS

In the development of the Plan, the Council uses existing federal and state codes and standards in its baseline as a starting point from which to estimate energy efficiency potential.[4] Any new codes and standards that take effect after the Plan represent codes and standards savings and count toward the Plan's goals. Since 1980, codes and standards savings have accounted for 15 percent of the total regional savings. Savings acquired through federal and state codes and standards are desirable for several reasons. First, their efficiency is realized at a lower total cost compared to ratepayer funded programs because they avoid program administrative costs. Second, they impact the entire market by removing lower efficiency equipment. Third, the savings are more equitable than ratepayer-funded programs because the cost of meeting a standard is borne directly by the consumers who benefit from the increased efficiency through lower power or natural gas bills.

New Federal Standards

Since the adoption of the Seventh Plan, the U.S. Department of Energy (DOE) adopted 15 new federal standards (13 electric, 2 gas). Table 4-2 below provides a list of new federal standards for electric appliances since the adoption of the Plan, including their effective date and estimated savings during the action plan period (2016-2021), although none of the savings will occur prior to 2018 (earliest compliance date for the standards listed). Most of these standards have yet to take effect; however, the Council estimates potentially 19 average megawatts of savings for these products after their compliance date and within the power plan's six-year action plan period.

Table 4 - 2: Federal Standards Finalized Post-Completion of the Seventh Plan[5]

Product Covered	Published Date	Compliance Date	Estimated Savings 2016-2021 (aMW)
Battery Chargers	2016	2018	1.3
Ceiling Fans	2017	2020	3.6

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[4] Seventh Power Plan incorporated estimated impacts of standards adopted prior to January 1, 2015 as well as two standards adopted in early 2015.

[5] Table does not include gas-fired appliances (e.g., furnaces and boilers)

Celling Fan Light Kits	2016	2020	0.4
Central Air Conditioners and Heat Pumps (Residential)	2017	2023	-
Central Air Conditioners and Heat Pumps (Commercial)	2016	2018	10.2
Computer Room AC Equipment	2018	2021	0.3
Dehumidifiers	2016	2019	0.3
Miscellaneous Refrigeration Products (Wine Coolers)	2016	2019	1.6
Pre-Rinse Spray Valves	2016	2019	0.2
Pool Pumps	2017	2021	0.2
Pumps, Commercial and Industrial	2016	2020	0.9
Variable Refrigerant Flow (Standard Pending)	2018*	2023	-
Vending Machines	2016	2019	0.2

* The variable refrigerant flow standard is pending.

In addition to these standards, changes to the lighting standard are anticipated to bring additional savings to the region. In the Seventh Plan, the Council assumed the baseline for lighting was the 2020 standard defined under the Energy Independence and Security Act of 2007. This required 45 lumens per watt for all lamps classified as general service lamps. Since the development of the Plan, the DOE expanded the definition for products covered under this definition, including reflector lamps which represent approximately 30 million units in annual sales nationally. However, there is a possibility this expanded definition will be changed or eliminated due to a legal settlement calling for DOE to revisit the rules and thus these savings may not be realized through the standard.

Since 2017, the Department of Energy has missed statutory deadlines for reviewing 15 standards and seven test procedures.[6] The standards include those for small electric motors, pool heaters, residential and commercial water heaters, clothes dryers, room air conditioners, cooking products, refrigerators and freezers, fluorescent lamp ballasts, commercial packaged boilers, computer room ACs, variable refrigerant flow ACs, water and evaporatively cooled ACs, and residential clothes washers. The missed test procedure deadlines include those for exit signs, traffic signals, water source heat pumps, metal halide lamp fixtures, small motors, room air conditioners, and fluorescent lamp ballasts. While the slowdown in federal standards does not have a marked effect on savings in the near-term, a persistent slowdown could have significant impact on long-term goals and increase the cost to utilities to achieve all cost-effective conservation.

New State Building Codes

Since completion of the Plan, Washington adopted a new residential and commercial building code, which went into effect in July 2016. Using the number of new homes built in Washington in 2016 and 2017, along with the estimated savings per home between the old and new code, NEEA estimated 0.7 average megawatts of savings for this new residential code. Most of these savings are from below-grade (underground) insulation improvements, ductless heat pumps, heat pump water

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[6] By statute (EISA 2007) DOE is required to review standards every six years and test procedures every seven years. Based on its review DOE can decide to retain the current standard or increase the minimum efficiency requirement. However, DOE is legally prohibited from relaxing the minimum efficiency requirement.

heaters, and low-flow showerheads.[7] NEEA is in the process of estimating code savings for the commercial sector. It is anticipated that code savings will increase over the coming years as more new homes are built and savings for the commercial sector are realized. Additionally, Washington is, or soon will be, in the process of updating its energy codes for both sectors, which are expected to take effect in July 2020.

In Oregon, updates to the residential energy code went into effect on January 1, 2018. On average, these new homes are anticipated to have an overall energy savings of 6 percent compared to the previous code used in the Seventh Power Plan. These savings are primarily from below-grade insulation and slab edge perimeter insulation upgrades, interior lighting improvements, low-flow showerheads, and improved insulating properties in skylights. The savings from new homes built in Oregon post-2018 will be captured in future iterations of the RCP. Oregon is also in the process of updating its commercial energy code, which may also provide some savings before the end of the six-year action plan period.

Montana utilizes the International Energy Conservation Code (IECC) 2012 for both its residential and commercial code. Idaho references IECC 2012 with amendments for residential and the IECC 2015 for commercial. Since development of the Seventh Plan, there have been no improvements to the energy codes in either Idaho or Montana. The IECC code was recently updated to a 2018 version with higher efficiency requirements. If either state adopts these updated codes within the next year, it would result in additional code savings by the end of the six-year action plan period.

For the six-year action plan period, NEEA estimates the total savings from improved state energy building codes for the four Northwest states to be 8.6 average megawatts for the residential sector and 4.2 average megawatts for the commercial sector, which assumes both Montana and Idaho adopt IECC 2018.

State Standards

At this time, no Northwest state has adopted any new standards. In 2018, the Washington State House of Representatives passed a bill to update standards for several products, but the bill did not pass in the Washington Senate. There are indications that the bill will be reintroduced in some form in the next legislative session in 2019. In Oregon, the Department of Energy began public meetings in June 2018 to consider a legislative concept to give the department more initiative and authority in the setting of efficiency standards. The plan is for the process to wrap up in 2018 and introduce new procedures to the legislature in 2019.

MARKET CHANGES

As energy efficiency programs and NEEA prove effective, markets start to transform, which also adds to energy savings.[8] The Council aims to capture these additional savings through collecting

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[7] The Washington residential energy code uses a point system with a variety of options for compliance.

[8] Although, as noted above, for many products, NEEA captures full market data and thus claims all market efficiency.

total regional market data provided by NEEA and the Bonneville Power Administration.[9] For the markets studied, the total regional savings reflect the difference in consumption of the market today relative to the Plan baseline. These studies are powerful in that they can look at the whole market (including both efficient and inefficient products) and provide useful insight as to what is naturally occurring outside of programs. The resulting data can provide useful direction to the region's utilities by informing them where markets are moving on their own and thereby allowing them to shift limited program resources to the markets that most need support.

In 2016 and 2017, the Council collected total regional savings reported by NEEA for a handful of residential markets: lighting, ductless heat pumps, refrigerators, heat pump water heaters, and clothes washers. There are several important insights from these data:

- Refrigerators and clothes washers markets are less efficient today than at the start of the Seventh Plan. In the case of clothes washers, this reflects a move in the market from more efficient front-loading machines to less-efficient top loaders. For refrigerators, this is due to a changing mix of configurations[10] and efficiencies sold in the market (as a percentage of total sales) relative to the Plan's baseline year (2015). These data may help utility programs to incent the more efficient options (front-load washers or super-efficient refrigerators) with a goal of achieving savings in these markets.
- There are significant savings achieved in the residential lighting market (43 average megawatts). The region's programs have touched approximately 60 percent of the efficient lamps in that market, indicating that there is a lot of efficiency occurring outside of programs as well. This change in the market is well aligned with the cost-effective potential in the Plan, meaning the region is on track in residential lighting.[11]
- Improvements are also being made in the ductless heat pump and heat pump water heater markets (9 average megawatts and 3 average megawatts, respectively). Yet significant cost-effective potential remains. This again suggests that additional program focus on these markets is likely necessary.

When possible, these market data are considered in estimating and adjusting the regional savings in the RCP. This reflects only those markets studied to date, which only cover about 10 percent of the total cost-effective potential. Other markets will be studied within the next few years (though for some markets the overall efficiency changes may not be known until after 2021). It also does not account for program baselines continuing to improve. Over time, the efforts of utility-funded initiatives will drive greater efficiency in the broader market, and fewer inefficient units will be sold.

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[9] Bonneville tracks these savings through their momentum savings research.

[10] For example, side-by-side refrigerator/freezer units generally consume more energy than top-freezer units.

[11] While this appears inconsistent with the overachievement of program savings shown in Figure 4-5, it is important to note that the program savings themselves are currently overstating progress in the residential lighting market due to assumptions in the baseline including some portion of efficient bulbs.

SECTION 5:
DEMAND RESPONSE

Contents

List of Tables and Figures

INTRODUCTION

This section will focus on key progress since adoption of the Seventh Plan for regional implementation of demand response. The Council will not update the demand response cost and savings assumptions from the Seventh Plan. Those updates will occur as part of the development of the Eighth Plan. The Council formed a demand response advisory committee (DRAC) in August 2016 that has assisted the Council in several key areas; namely: defining demand response, providing data on planned and existing demand response programs, and highlighting key barriers to demand response implementation.

DEMAND RESPONSE DEFINITION

In June 2017, the DRAC adopted a definition for demand response:

> *Demand response is a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties.*

PLANNED AND EXISTING DEMAND RESPONSE PROGRAMS

With extensive input from the DRAC, Council staff developed a template for the utilities to use to record historical and current demand response programs, along with planned programs. The template includes the type of program, the amount of curtailed electricity capacity (realized and planned), and other information such as: seasonality, cost, and callable hours.

From what has been reported using this template, as well as information directly from utility integrated resource plans, it is apparent most of the region's investor-owned utilities and some public utilities incorporate demand response into their resource planning. Some utilities like Idaho Power and PacifiCorp are planning to continue their existing demand response programs that provide over 500 megawatts of impact in the region during the summer season, primarily from irrigation load control.[1] Other utilities that currently do not have large-scale demand response programs find a need for demand response in the next 5 to 10 year timeframe (e.g. Portland General Electric, Avista, Puget Sound Energy). The Bonneville Power Administration found demand response to be part of the portfolio to meet its summer capacity needs in its 2018 resource program.

KEY BARRIERS TO DEMAND RESPONSE IMPLEMENTATION

The DRAC has spent significant time discussing the barriers to demand response. In addition, Bonneville contracted a study to explore the barriers among different parties potentially affected by DR programs (BPA power customers, internal subject matter experts, DR service providers, and external stakeholders). In all cases, the identified economic/market barriers are the most significant to demand response adoption. Without a clear valuation metric (e.g. currently no capacity market), it is difficult for many to justify demand response investment. Other identified barriers include: regulatory (lack of established tariffs), infrastructure (data handling protocols), organizational (intra-organizational communication), and perceptual (customer understanding). The DRAC will be exploring ways the region may mitigate these barriers over the next year or so.

This figure, from the Bonneville demand response barriers report,[2] illustrates these barriers:

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[1] PacifiCorp also has large demand response programs outside the region in its Utah service territory.

[2] https://www.bpa.gov/EE/Technology/demand-response/Documents/180319_BPA_DR_Barriers_Assessment.pdf

Figure 1 – 1 Barriers to Demand Response, from Bonneville Study

ECONOMIC/ MARKET	• Lack of defined BPA need for and value of DR • Low power costs • Lack of a region-wide framework for valuing and pricing DERs* • Absence of organized commercial DR market in the Northwest • Inadequate/inconsistent price signals* • Cost of development and deployment • Lack of power customer business case
ORGANIZATIONAL/ OPERATIONAL	• Competing priorities for human and financial resources • Lack of staff knowledge and capability • Insufficient intra-organizational coordination/communication • DER reliability and dispatchability*
INFRASTRUCTURAL/ TECHNOLOGICAL	• Lack of advanced metering infrastructure deployment • Poor “big data” analytical tools and capabilities • Lack of uniform communications protocol; Interoperability issues • Difficulty integrating DR with existing infrastructure and back office systems • Need for investment in back-end technologies
LEGAL/ REGULATORY	• Trading DR resources across balancing authorities* • Lack of established tariffs and contractual framework for DR
PERCEPTIONS	• Perceived lack of BPA long-term commitment* • Weak end-use customer demand for DR programs* • Perceptions of end-user participation

REGIONAL ATTRIBUTES SUPPORTING DEMAND RESPONSE

Although there are significant barriers, as detailed above, the region also has several characteristics that support expansion pf demand response. These include the long history of energy efficiency and regional collaboration, growing participation in the western Energy Imbalance Market, and high potential for demand response due to its high electric water heater penetration and growing penetration of electric vehicles. Utilities are finding value in demand response not only as a means to mitigate peak load capacity constraints, but also as part of the solution set for non-wires alternatives.

SECTION 6:
GENERATING RESOURCES

Contents

List of Tables and Figures

INTRODUCTION

This section provides an update of electricity generating resources and state level policies affecting long term resource strategies since the adoption of the Seventh Power Plan (Seventh Plan).

The estimated costs of onshore wind, solar photovoltaic (PV), and frame natural gas peaker plants have declined substantially because of technology innovations, manufacturing improvements, and increased competition between engineering, procurement, and construction (EPC) vendors. On the other hand, the estimated cost of combined cycle gas and reciprocating engines are nearly the same.

The national trend of economically driven coal plant closures has continued. Retirement of 3,700 megawatts worth of regional coal resources within the next 15 years has been formally announced through state regulatory commission filings or indicated as a likely future scenario in regional utility integrated resource plans (IRPs). Of this, about 1,900 megawatts is directly owned by utilities to serve their load and the remainder is owned by independent power producers who can contract with utilities, direct access customers, or other market participants within or outside of the region. No new natural gas or coal plants have begun construction in the region since the adoption of the Seventh Power Plan.

The state of Oregon created an energy storage mandate that could lead to the contracting of up to several dozen megawatts of battery storage by 2020. A separate bill updated the state's renewable portfolio standard (RPS) to require that utilities remove all coal from their resource mix by 2035 and serve 50 percent of energy with renewable resources by 2040. This revised standard includes higher interim targets that exceed the final 25 percent by 2025 in the original RPS bill, driving additional and earlier renewable resource development. Limits around eligible resources were unchanged from the original standard[1].

The state of Washington did not modify its renewable energy requirement; however, it did create a tax incentive which led to the creation of a green tariff program[2]. This program is structured such that the utility can contract for the development of a new renewable resource and will offer all of the energy and associated renewable energy certificates (RECs) from that project to a subset of interested commercial and industrial customers. The resource is not included in the utility's own rate base and is not used for utility renewable energy compliance accounting. A similar program is also being offered by an Oregon utility in a trend that is beginning to gain traction and popularity throughout the country.

All states in the region contemplated and took some action on Public Utility Regulatory Policies Act (PURPA) related policies after substantial new wind and solar began to be developed in Oregon, Montana and Idaho. The result has been a slowdown or halt in development of PURPA-driven projects, but not before hundreds of megawatts of new resources were already in place.

Cost declines, coal retirements, and state policy changes have together led several utilities within the region to issue new requests for proposals (RFPs) for generic capacity, demand response, and renewable resources. Not all of the renewable resource development is based on near-term compliance or capacity need, however. PacifiCorp and Portland General Electric (PGE) both brought forth RFPs in advance of compliance need with the goal of capturing the benefit of the soon-to-expire federal tax credits and PacifiCorp showed in their 2017 IRP that an investment to repower wind turbines with the PTC benefit would result in substantial portfolio savings on the basis of increased production of very low cost energy from the larger, more efficient turbines.

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[1] Details of regional RPS policy are summarized at https://www.nwcouncil.org/sites/default/files/p1_17.pdf

[2] https://myavista.com/about-us/energy-innovations/solar-power

A summary of RFPs that are currently active in the region is shown in Table 6-1 and a more detailed description of each specific driver follows below.

Table 6 - 1: Current Requests for Proposals, as of January 2019

Utility	Resource	Notes
Avista	50 MWa (~150 MW) of renewables	Goal is to procure least-cost energy to offset market purchases and fossil-fueled generation. This is in addition to the 28 MW (DC) acquired for the Solar Select green tariff.
Portland General Electric	100 MWa (~300 MW) of renewables by 2021	
Puget Sound Energy	(1) Demand Response, and (2) Capacity and Renewables	PSE has identified a capacity deficit of about 300 MW beginning in 2022 in addition to a need for RECs. PSE indicated they could also increase their market position through a transmission redirect[3] of their existing Colstrip 1 and 2 rights to eliminate the capacity need without adding additional resources.
PacifiCorp	(1) Up to 1,270 MW of wind, and (2) additional incremental solar	The Oregon Public Utilities Commission declined to acknowledge the short list of bids for the wind RFP in May 2018 while other commissions approved the majority of projects on the shortlist. PacifiCorp is moving ahead with the development of 1,150 MW of new wind along with a 140 mile, 500 kV transmission line required for these projects. The incremental solar RFP is no longer active.

UPDATED CAPITAL COSTS FOR SEVENTH PLAN TECHNOLOGIES

The Council refreshed capital cost estimates for several generating resource technologies from the Seventh Power Plan. This has been done with input from the Council's Generating Resources Advisory Committee (GRAC) and can serve as a reference for the region. Table 6-2 displays the Seventh Plan resource costs for specific reference plants and an updated estimated cost range for the midterm assessment. For the 2021 Power Plan, the Council will reassess all candidate

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[3] A transmission redirect is a request from a transmission rights holder to change the Point of Receipt (where energy enters the system) on their contract from one location to a new location. An entity without the opportunity to redirect existing rights would otherwise need to enter the new transmission request queue. A redirect request from a contract holder is evaluated by the transmission owner to ensure reliability can be maintained.

generating resource options and develop new reference plants with updated cost estimates, capacity factors, heat rates, resource potential, and other planning parameters.

Several federal policy changes affecting resource costs have taken place since the release of the Seventh Plan. While the Investment Tax Credit (ITC) and Production Tax Credit (PTC) have not changed, the corporate income tax rate has been lowered from 35 percent to 21 percent which lowers the value of tax credits since they are used to lower pre-tax income which is now taxed at a lower rate. Additionally, interest rates are beginning to rise and tariffs have been placed on imported solar cells, steel, and aluminum. The impacts of these changes and additional technology specific innovations and market changes are discussed for each resource, below.

Table 6 - 2: Updated Capital Costs for Seventh Plan Resources

Resource Technology	Seventh Plan (2016$/kW)	Midterm Assessment Update (2016$/kW)	Trend
Solar Photovoltaic (PV) 20 MW	$1,791 / $2,566	$1,350 - $1,500	Decrease (25-60%)
Wind (onshore) 100 MW	$2,382	$1,500 - $1,700	Decrease (30-40%)
CCCT Adv Wet Cooling 1x1 370 MW	$1,220	$1,100 - $1,300	Slight decrease
CCCT Adv Dry Cooling 1x1 425 MW	$1,369	$1,200 - $1,400	Slight decrease
Frame GT 200 MW	$859	$500 - $650	Decrease (30-40%)
Reciprocating Engine 220 MW	$1,382	$1,250 - $1,450	No change

Solar Photovoltaic (PV)

Third party bottom-up analyses[4] and recently executed contracts demonstrate continued steep cost declines for solar PV, primarily due to module price improvements. The Seventh Plan included mid- and low-range estimates for solar capital costs and observed trends since then are tracking at or below the low-range forecast.

It is important to note that the recent analyses and contracts used to track cost trajectories have not yet had the effects of recent federal policy changes priced in. It is expected that the 25 percent steel and 10 percent aluminum tariffs will have a small increase in solar capital costs because of increased racking expenses. Likewise, it is expected that the solar cell tariff (30 percent on imported cells decreasing by 5 percent per year with the first 2.5 GW of imports exempt) will have a modest first year impact that will decline through the four years that the tariff is in effect. A potential balance

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[4] A bottom-up analysis tracks and adds component costs (e.g. module, inverter, racking, soft costs, etc.) to arrive at a total resource cost. This is in contrast to top-down approaches which attempt to track the final resource cost without insight into the component breakdown.

to these increased cost drivers are recent changes in international renewable policy that may create conditions of short term global module oversupply that could drive module prices down further. Additionally, growth in the solar market was not as robust in 2017 as it had been in 2016 which may cause EPC vendors to decrease their margins, thereby lowering solar soft costs (non-hardware) which have otherwise been stable. There are many balancing factors which push costs in both directions over the near term.

Because a substantial number of executed contracts and analyses available to demonstrate cost trends since the release of the plan, the Council is not differentiating between a mid- and low-range solar cost for the midterm assessment. Instead, the Council is now estimating the cost of solar throughout the region to be in the range of $1,350 - $1,500/kW (compared with the Seventh Plan “low-range” of $1,791).

As with the Seventh Plan, the ITC benefit is not included in the cost estimate because the value of the ITC depends on the year of construction start.

Table 6 - 3: Value of Investment Tax Credit

Construction Start Year	Value of ITC Benefit
2016 - 2019	30%
2020	26%
2021	22%
2022 and on	10%

Wind (Onshore)

Onshore wind development across the United States has been so substantial that installed capacity of wind across the country now exceeds that of hydropower. Capacity factors for new projects are increasing because of larger blades at higher hub heights, and capital costs are declining as equipment prices improve. In combination with lower cost financing for a now stable industry, the wind-rich central United States has recently seen executed power purchase agreement (PPA) prices below $20/MWh.

Wind additions in the Northwest specifically have continued the trend seen at the time of the Seventh Power Plan of being relatively modest. The majority of the total regional installed capacity has come in the six years immediately following the enactment of state RPS. The smaller group of regional projects that have been developed recently have primarily been PURPA contracts[5] or corporate offtaker arrangements and have utilized Safe Harbor[6] equipment which captures the full benefit of the PTC. While this does not directly impact the capital cost of onshore wind, it does

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[5] PURPA, the Public Utility Regulatory Policies Act, has recently led to a substantial amount of wind and solar development in the Pacific Northwest. PURPA requires a utility to purchase power from an independent power producer at the utility’s cost to otherwise produce or acquire it (known as the ‘Avoided Cost’).

substantially reduce their levelized cost of energy through tax equity investment and is already accounted for in the low PPA prices seen throughout the country.

The Seventh Plan did not include the PTC benefit because there was not an RPS compliance need to acquire additional renewables in advance of the PTC expiration (see Table 6-4), however, as noted, this had no impact on the overnight capital cost estimate; the PTC only impacts the levelized cost of energy represented by PPA prices.

Table 6 - 4: Value of Production Tax Credit

Construction Start Year[6]	PTC Benefit (%)	Value of PTC Benefit ($/MWh)
2015 and 2016	100%	$24.00
2017	80%	$19.20
2018	60%	$14.40
2019	40%	$9.60
2020 and on	0%	-

The updated onshore wind capital cost estimate is $1,500 - $1,700/kW (compared with the Seventh Plan Estimate of $2,382)**.** This is strictly the cost of wind capacity and does not include any tax benefits or fixed costs for transmission rights[7].

Natural Gas

While natural gas technologies are fairly mature, there are advances and innovations to be made as manufacturers aim to develop more efficient and flexible machines. As the need for more flexible resources grows to integrate variable energy resources (as opposed to operating as strictly baseload resources), natural gas plants that can adjust quickly to new or differing types of load are increasingly in demand. While there have been limited new gas plant developments in the Pacific Northwest and Western United States in recent years, that may change as utilities and energy service providers grapple with coal plant retirements and evolving needs for additional capacity.

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[6] Construction Start is defined by the IRS as spending 5 percent of total cost of project or undertaking significant physical work (excavating turbine sites, building roads, etc.). Projects must then be operational by Dec. 31 four years after construction start to take safe harbor benefit. Safe harbored equipment locks in the PTC benefit such that projects which go to contracting even years after the official construction start date can still capture the initial, larger value of the PTC.

[7] While it does not affect the capital cost of wind, the cost of long-term transmission rights can substantially increase the levelized cost of energy - and therefore the PPA price - for wind and other resources. This is especially true if the resource is distant and must wheel across multiple system owners. See https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Pages/Montana-Renewable-Energy.aspx for an example calculation.

The updated capital cost estimates of gas technologies follow varying trajectories from the estimates in the Seventh Plan, as described below. The impact from the steel and aluminum tariffs is expected to be minimal, if any, across all gas technologies.

Combined Cycle Combustion Turbine

Manufacturers have been working to improve the performance (output) and efficiency (conversion of fuel to energy) of typical baseload combined cycle combustion turbine (CCCT) technologies. The recent advanced technology classes – H, J, K[8] – have surpassed the long sought after 60 percent fuel conversion rate (equivalent to heat rates in the low 6,000s in btu/kWh) and manufacturers are beginning to turn their attention towards increased flexibility. By promoting the technology as both a baseload and load following resource, CCCTs may soon be competing with gas peakers in the growing market for flexible resources.

The Seventh Plan modeled two advanced CCCTs, one with wet cooling (typical in the existing fleet of gas resources in the region) and one with dry cooling (more expensive but reduces the need for water rights). Since the adoption of the Plan, the overnight capital cost of CCCTs has decreased slightly, however the estimates from the Plan are still well within the updated range of $1,100 - $1,300/kW for an advanced 1 (gas turbine) x 1 (steam turbine) CCCT with wet cooling and $1,200 - $1,400/kW for an advanced 1x1 CCCT with dry cooling.

Simple Cycle Combustion Turbine – Frame

In the past decade or so, frame gas turbines have gone through an evolution in how they are primarily used. Traditional heavy duty, inefficient (high heat conversion rate) frame units were used to provide supplementary power for a few days several times a year. New advanced class frame turbines are larger (higher capacity), more efficient machines with improved ramping and load following capabilities that enable them to compete with more flexible gas peakers (such as aeroderivatives, intercooled engines, and reciprocating engines).

While the capital cost of combined cycle combustion turbines has only decreased marginally since the Seventh Plan, the cost of frame gas combustion turbines in simple cycle mode has decreased significantly. Updated analysis suggests that the capital cost of new frame units ranges between $500 - $650/kW, a decrease of 30 to 40 percent. The decrease in the cost of equipment over the last several years accounts for about a ten to fifteen percent reduction. There have also been fewer frame gas turbines built in recent years, so the competition amongst EPC vendors has led to much lower bids in order to secure contracts.

Reciprocating Engine

Reciprocating engines are typically the most expensive type of gas peaker, but can also be the most flexible and responsive in terms of ramping up and down to meet load. Compared to other gas

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[8] In general, improvements leading to significant increases in capacity and efficiency constitute a new class of turbine.

peakers, reciprocating engines are the newcomers to the market. In the Pacific Northwest, there is only one reciprocating engine gas peaker plant – Port Westward II. However, Wärtsilä, one of the leading reciprocating engine manufacturers, has recently secured several contracts to build plants in the United States.

There has not been any notable change in the capital cost of reciprocating engines since the Seventh Plan's adoption. For the midterm assessment, the updated estimate is a range between $1,250 - $1,450/kW.

RESOURCE ACQUISITION AND RETIREMENTS

Since the adoption of the Seventh Power Plan in February 2016, there has been moderate development of new resources – especially when compared to the natural gas and wind resource boom of the 2000's and early 2010's. In total, about 1,100 megawatts of new resources have been acquired in the region – see Figure 6-1.

- Solar – Between 2016 and 2018, about 555 megawatts of solar came online in the region. While the majority was in small projects built through PURPA contracts in Idaho and Oregon, in 2016 Avangrid developed a 56 megawatt solar project with a long-term power purchase agreement with Apple, Inc. This recent and growing national trend of corporations securing renewable energy directly, as opposed to purchasing power through a utility, will likely continue in the region. The region will also likely see the development of community solar installations and/or green power initiatives resulting from utilities aiming to preserve their corporate customers.
- Wind – Over the past three years, 190 megawatts of wind came online, most of which were in projects built out of region with long-term power purchase agreements to regional investor owned utilities (IOUs).
- Natural Gas - In 2016, Portland General Electric commissioned the 440 megawatt Carty Generating Station (combined cycle combustion turbine natural gas plant).
- Hydropower – In 2018, Snohomish PUD added 12 megawatts of new low impact hydropower through two projects on the Snoqualmie River. In addition, the continued widespread effort to upgrade aging hydropower projects through equipment replacements and rewinds has resulted in additional capacity and efficiency from the existing system.
- Battery storage - Several utilities have developed small battery storage projects at pilot scale. The total of these projects is on the order of less than several megawatts. However, an energy storage mandate passed in 2016 in Oregon has stipulated the contracting for development of up to several dozen megawatts of energy storage by 2020.

While the Seventh Power Plan anticipated and included in its existing resource base the commissioning of Carty and about 400 megawatts of solar PV, the remaining new and proposed resources are primarily being driven by PURPA agreements, state renewable portfolio standards, utility green tariff energy programs, and individual utility needs based on integrated resource plans.

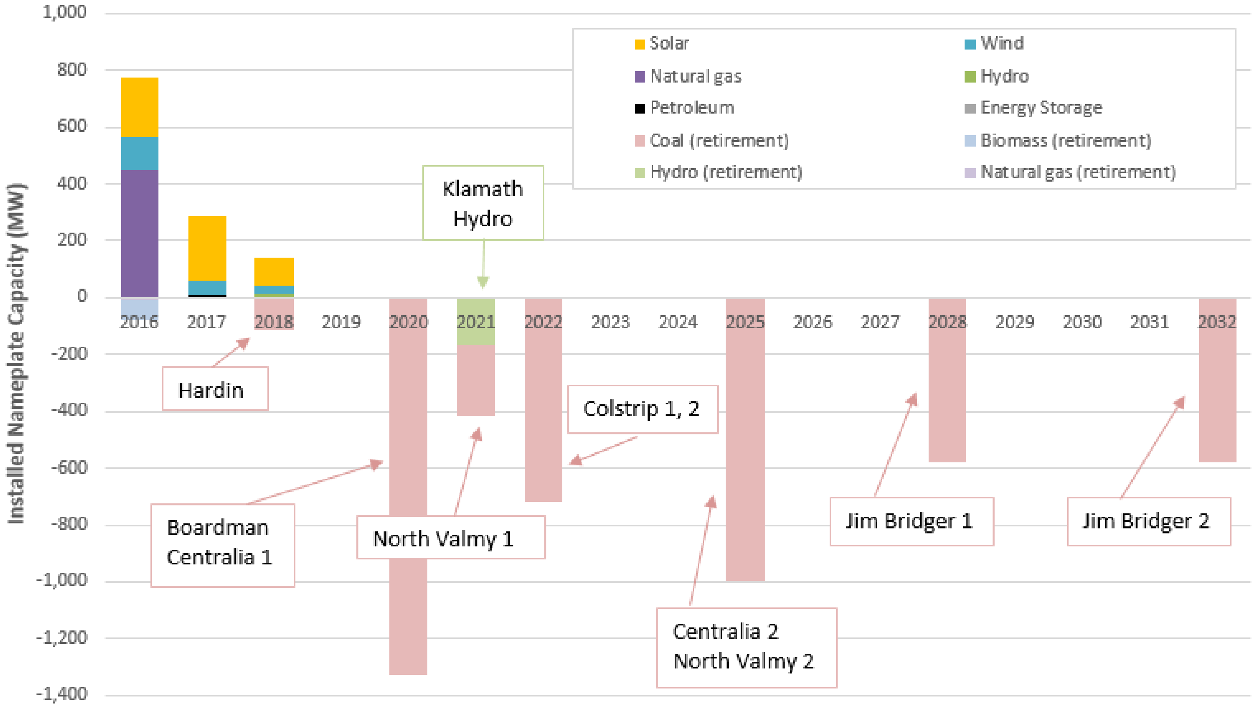
Resource retirements in the region have been minimal, with the closure of a small cogeneration natural gas plant in Idaho and about 60 megawatts of woody residue biomass plants. As demand for paper and newsprint has declined over the past decade, several local wood product manufacturers have suspended operations. Without the biofuel waste produced from the factories, the biomass plants have been forced to close as well.

The Seventh Plan included the planned retirements of Boardman, Centralia, and North Valmy, but since then there have been other major coal retirement announcements:

- In 2017, the owners of Hardin Generating Station in Montana announced that a closure was imminent in 2018 unless a new buyer could be secured. As of early 2019, Hardin is operating through a short-term contract while a potential long-term contract with a local blockchain company is being formulated.
- Puget Sound Energy and Talen Energy announced an agreement in 2017 to close Colstrip units one and two by 2022.
- In their respective 2017 IRPs, PacifiCorp and Idaho Power indicated their intentions of retiring Jim Bridger units one and two in 2028 and 2032. Additional analysis is ongoing.

There is uncertainty regarding replacement needs and strategies to compensate for the lost resources. Table 6-5 lists the announced coal retirements in the region, inclusive of independent power producers selling to utilities, direct access customers and other market participants. This is also illustrated in Figure 6-2, highlighting the magnitude of resource retirements over time. Table 6-6 provides a summary of the net balance of anticipated coal retirements and new resource additions over time as forecast through current utility IRPs.

Figure 6 - 1: Additions and retirements (including announcements) since the Seventh Plan



* Uncertainty remains regarding the future of Hardin; While Idaho Power is ending its participation in North Valmy 1 in 2019, according to NV Energy it will remain in operation until end of year 2021

Table 6 - 5: Announced Planned Coal Retirements in the Pacific Northwest*

Plant	Retirement Date	Capacity & Operating Year	Location	Ownership
J.E. Corette	2015	173 MW (1968)	MT	PPL Montana
Hardin	2018	116 MW (2006)	MT	Rocky Mountain Power[1]
North Valmy 1 North Valmy 2	2021[2] 2025	254 MW (1981) 268 MW (1985)	NV	Idaho Power, Sierra Pacific Power (50/50)
Boardman	2020	600 MW (1980)	OR	Portland General Electric, Idaho Power (90/10)
Centralia 1 Centralia 2	2020 2025	670 MW (1971) 670 MW (1971)	WA	TransAlta
Colstrip 1 Colstrip 2	2022	360 MW (1975) 360 MW (1976)	MT	Puget Sound Energy, Talen Energy (50/50)
Jim Bridger 1 Jim Bridger 2[3]	2028 2032	578 MW (1974) 578 MW (1975)	WY	PacifiCorp (2/3)[4], Idaho Power (1/3)
Regional Utility Total		**1,899 MW**		
Regional Total (incl. IPPs)		**3,772 MW**		

[1] Not related to PacifiCorp

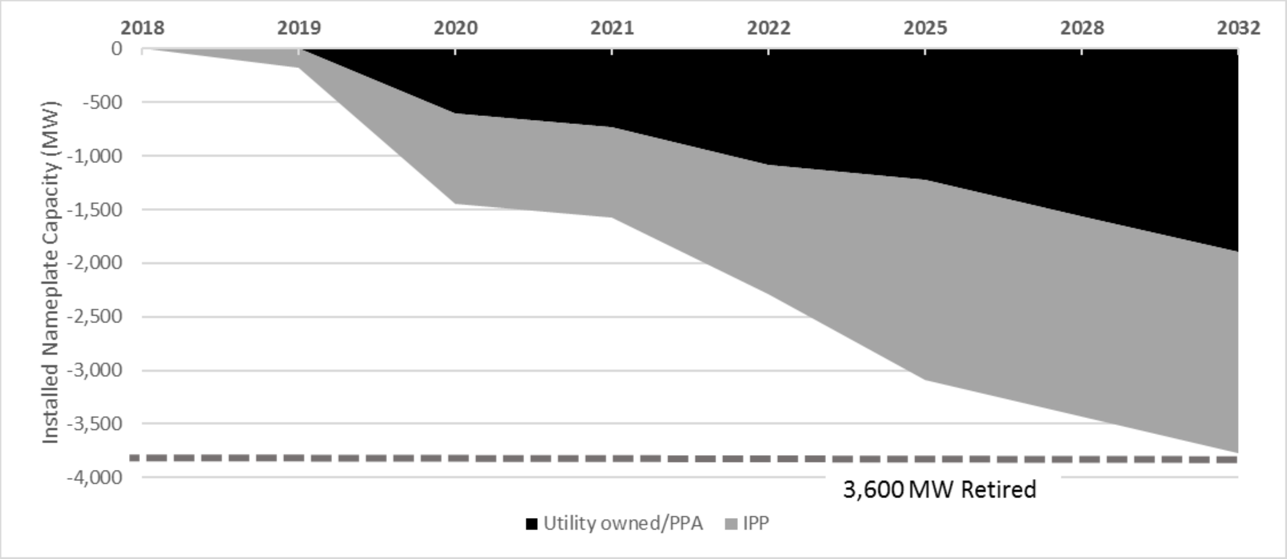
[2] Idaho Power will end its participation in 2019, NV Energy to retire unit end of year 2021 per 2019 IRP

[3] Per PacifiCorp's 2017 IRP Update

[4] Regional total includes only PacifiCorp's load to the region (38%)

* For detailed project information, please see the Council's generating resources project database

Figure 6 - 2: Total Regional Utility + Independent Power Producer Coal Retirements



* Note: J.E. Corette is not included in this figure because it retired in 2015. This figure shows 2018-2037.

Table 6 - 6: Net Balance of Coal Retirements and Anticipated New Capacity Additions In MW

All numbers in units of MW	**2018 thru 2020**	**2021 thru 2025**	**2026 thru 2030**	**2031 thru 2037**	**Cumulative 2018-2037**
Anticipated Additions	17	379	1,237	2,155	**3,788**
Anticipated Coal Retirements (prorated to reflect % serving Northwest)	(1,270)	(981)	(1,010)	(339)	**(3,600)**
Net Balance Over Period	(1,253)	(602)	227	1,816	**188**

* Note: J.E. Corette is not included in this table because it retired in 2015. This table shows 2018-2037.

RENEWABLE PORTFOLIO STANDARDS

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana in the mid-2000s led to a significant increase in renewable resource development. After utilities met their state mandated targets (2015, 2020), renewable development in the region began to decline in

2013[9]. The average regional resource build-out in the Seventh Plan introduced new renewable resources for compliance with state RPS toward the end of the planning period. This took into account RECs from existing renewable projects that were not under long-term contracts.

Since the adoption of the Seventh Plan, Oregon updated its RPS through Senate Bill 1547 and adopted a new target of 50 percent renewables by 2040. In order to capture the most benefit from the expiring federal tax incentives, both Portland General Electric and PacifiCorp have recently pursued requests for proposals for resources and RECs that will be operational by the end of 2020 to the tune of about 1,500 megawatts. Table 6-1 lists all of the current resource acquisition efforts through RFPs.

The Seventh Plan encouraged utilities to explore additional qualifying renewable technologies to comply with RPS, in particular solar PV and geothermal[10]. As the cost of solar has continued to decline, utilities have been analyzing and pursuing solar as part of their compliance strategies. In addition, utilities have acquired small biomass and geothermal resources, as well as upgrades to existing hydropower projects.

Overall, including the latest strategies for compliance in Oregon, the region is once again well poised to meet the near-term RPS targets. It is likely that post-2020, additional resources and RECs will need to be analyzed and acquired to meet later targets (see figure 6-3, based on current and updated utility IRPs). This is consistent with the Seventh Plan, which highlights the reality that utilities are unique (for example, some utilities are long on resources, some are short) and face varying circumstances in the timing of new resource acquisition.

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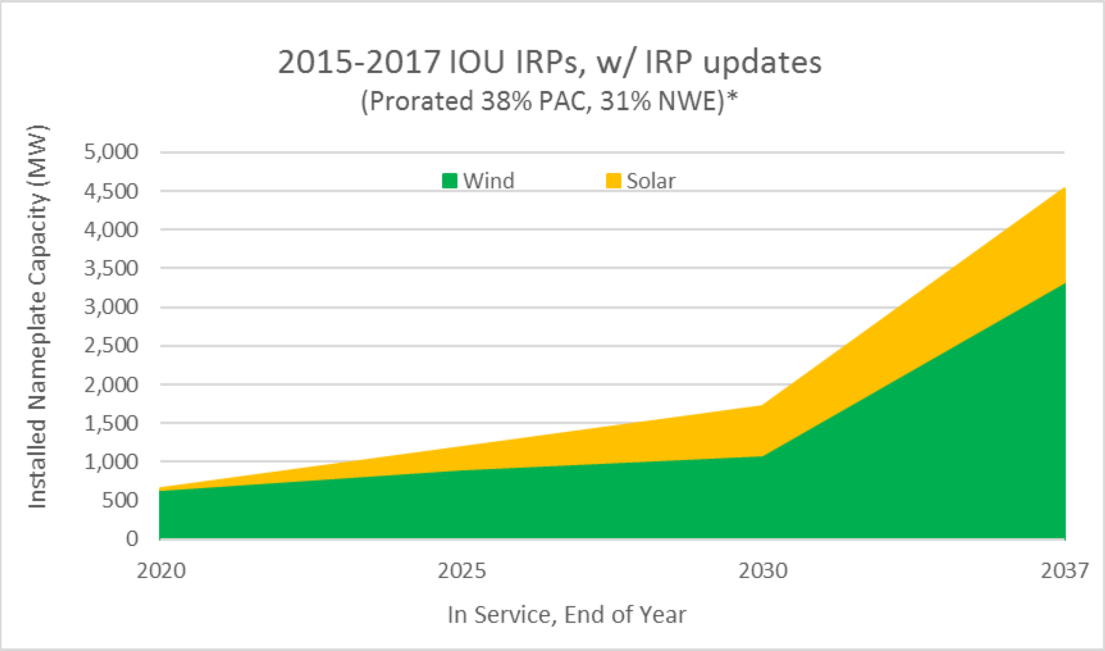
[9] In addition, uncertainty over the expiration and renewable of Federal tax incentives contributed to a slowdown in development.

[10] See Seventh Power Plan, Chapter 4, Action item RES-6

Figure 6 - 3: Anticipated Cumulative Renewable Resource Additions



* PacifiCorp and NorthWestern Energy's percentage of load serving the region

EMERGING TECHNOLOGIES

The Seventh Power Plan evaluated all candidate generating resource technologies and characterized each as either a primary, secondary, or emerging technology[11]. The plan created an action item, ANLYS-14, to monitor and track emerging technologies generally as well as action item ANLYS-15 to track ocean wave energy specifically.

The Council has continued to track development trends related to the emerging technologies identified in the Seventh Plan (wave energy and small modular reactors) and will re-evaluate the characterization of these and all other resources in the development of the 2021 Power Plan. Additionally, while the Council considered energy storage as a secondary (as opposed to emerging) technology, action item ANLYS-14 specifically noted a focus on energy storage among other technologies and action item ANLYS-16 directed the development of an energy storage whitepaper. The Council has been very engaged in the region's energy storage activities across all technology types and has been carefully tracking innovations in technology readiness levels, deployments, costs, policies, and utility planning activities. The Council's white paper provides a summary of the regional landscape[12].

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[11] See Seventh Power Plan, Chapter 13

[12] See "White Paper on the Value of Energy Storage to the Future Power System"

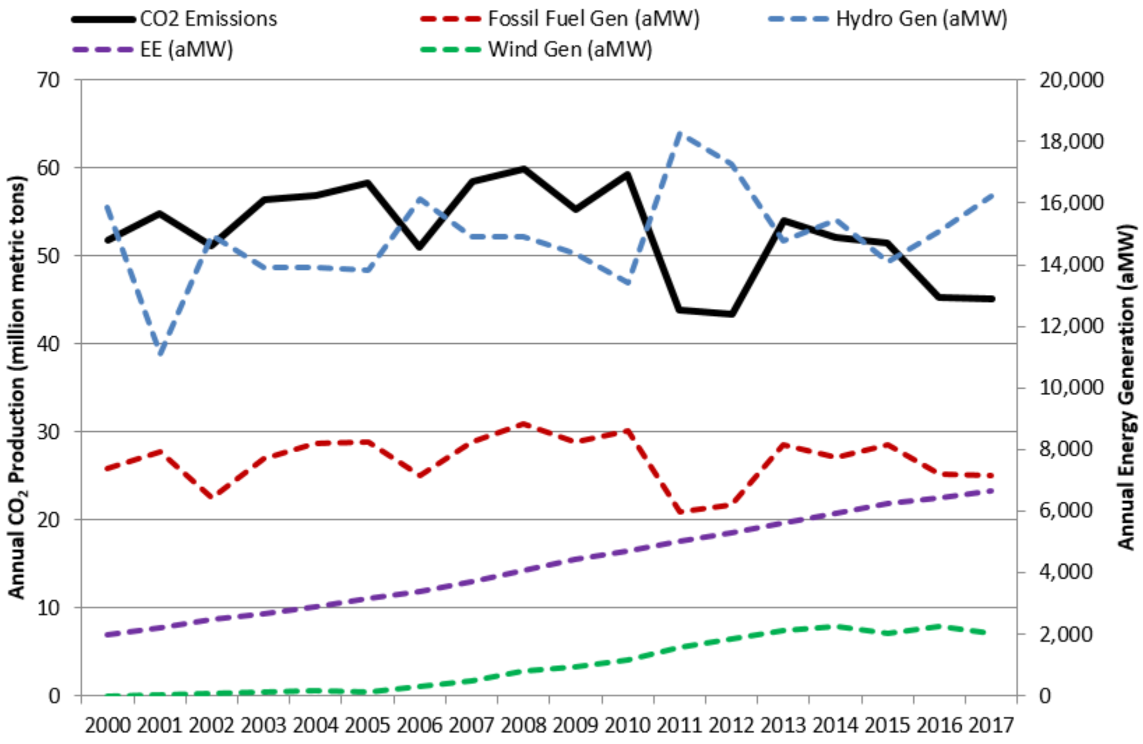
In addition to evaluating storage as a standalone resource, the Council will consider guidance on how to include storage in combination with other resource types such as wind, solar, or peaker gas plants for the 2021 Power Plan.

CARBON EMISSIONS FROM ENERGY GENERATION

The region's carbon dioxide emissions from energy generation since the year 2000 have averaged just above 50 million metric tons, bouncing around and reaching as high as 60 million metric tons in 2008 and as low as 43 million metric tons in 2012 (see Figure 6-4). In the Pacific Northwest, carbon emissions are directly affected by the region's abundant hydropower resource. In a good hydro year, when the runoff is above average, the region's fossil fuels are dispatched less and emissions are lower. In a poor hydro year, when the runoff is below average, the region may rely more on fossil fuels and emissions are higher.

In 2016 and 2017, emissions were around 45 million metric tons, a marked decrease from the previous several years but still within the range seen in the last two decades. However, as the region's coal plants are dispatched less (due to economics and planned retirements), natural gas plants are dispatched more (at half the emissions rate of an average coal plant), and generation from energy efficiency and renewable resources grows, the region's carbon emissions will begin to decrease.

Figure 6 - 4: Annual Pacific Northwest Carbon Emissions from Electricity Generation



SECTION 7:
RESOURCE STRATEGY IMPLICATIONS

Contents

IMPACT ON THE RESOURCE STRATEGIES FROM THE SEVENTH PLAN

To ensure the region an adequate, efficient, economic and reliable power supply the Seventh Plan resource strategy relied primarily on cost-effective energy efficiency and demand response. In the six-year action plan, there were rare cases in which additional natural gas generation was needed to keep the system adequate. This midterm assessment examines what has happened since the release of the Seventh Power Plan. One key purpose of the assessment is to examine if there is substantial reason to question the resource strategy put forward in the Seventh Plan. The Council's finding is that the resource strategy put forth in the Seventh Plan is still a sound plan for the region to maintain an adequate, efficient, economic, and reliable power supply.

Electricity and natural gas prices have continued to be low since the plan was adopted, but they are well within the ranges examined by the Regional Portfolio Model. The region continues to see the impacts of the expansion of solar generation in California where there is recent state legislation that will further expand the state's Renewable Portfolio Standard. However, under Seventh Plan assumptions, the Regional Portfolio Model selected resources primarily based on adequacy needs. Using the same adequacy standard as the Seventh Plan, it is unlikely that the minimal reduction in price forecasts or the increase in the California build of solar would impact the resource strategy within the action plan time period.

The first two-year milestone in the Plan's energy efficiency targets has been achieved. The Seventh Plan found that acquiring 1400 aMW by 2021 would be cost-effective for the region. While there have been minor shifts in the load forecast and some substantial moves in the cost of generating resources, there have also been additional thermal retirements announced since the release of the plan. Given the potential identified in the plan, it is unlikely that the region would have the ability to develop significantly more than 1400 aMW of energy efficiency by 2021. But conversely, any changes in the region since the Plan's adoption seem unlikely to reduce the amount of energy efficiency identified in the resource strategy. Given the wide range of scenarios examined in the

Seventh Plan, it is likely any of the potential changes would be well within the range of conservation development already explored.

Demand response played a key role in the Seventh Plan resource strategy, primarily in maintaining regional adequacy. Even with the additional announced retirements of large thermal plants and an anticipated increased development of variable generating resources, most of the changes in the region since the Seventh Plan would be very unlikely to change that result. Since 600 MW or more demand response was developed in every scenario other than the scenario that explored increased reliance on out-of-region resources, the Seventh Plan indicated that it would be cost effective to see an incremental development of a minimum of 600 MW of demand response. At this time, continued investment in demand response still seems to be a reasonable way for the region to mitigate risk during periods of peak need.

Generating resource data has had the largest shift since the Seventh Plan. There have been substantial cost reductions for developing wind and solar resources and changes in the cost of natural gas generation as well. While these changes would likely impact the resource strategy, the impact would be negligible within the six-year action plan period since most of the natural gas and renewable generation expansion in the scenarios was projected for 2021 or after.

The circumstances on the ground have changed since the Seventh Plan. However, the findings from the plan emphasized a robust strategy for developing new resources. Looking back through the input data the Council used in the plan and projecting what the likely changes would be, the Council does not anticipate these changes would result in a different strategy.

ADEQUACY UPDATE

The most recent adequacy assessment continues to show an expected deficit of resources after 2020. In fact, all three assessments since the Seventh Plan (for operating years 2021, 2022, and 2023) show consistent results with the findings in the Seventh Plan and do not provide a reason to revise the resource strategy in the plan. The latest assessment identified an expected need of 300 megawatts of capacity by 2021 to maintain adequacy and an additional need for 300 to 400 megawatts by 2022. The amount of needed capacity is well within the range of available cost-effective supply identified in the Seventh Plan. Regional utilities have also forecast an expected capacity need by 2021, as evidenced in their integrated resource plans, and have identified sufficient amounts of capacity that could be developed in time to cover expected needs. However, while it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could alter the outcome. For example, greater than anticipated demand growth, lower than anticipated out-of-region market supplies or a combination of both could significantly increase the amount of needed capacity. On the other hand, lower demand growth or higher than expected market supplies could reduce the need for new capacity altogether. These conditions are less likely, but should they occur, the resource strategy from the Seventh Plan is sufficiently flexible and wide to cover the full range of future resource need.

The estimated need for 600 to 700 megawatts of new resource capacity by 2022 assumes limited available out-of-region market supply. If the region can fully utilize available transmission from California, then there would be enough to meet the region’s entire new resource need by 2022. However, because of uncertainties surrounding the availability and delivery of imports, the Resource

Adequacy Advisory Committee recommended that the Council assume a more conservative level of import supply.

Summer Capacity / Reserves

The Seventh Plan predominantly identified a winter need for adequacy in the action plan period. When looking at the load forecast, we see a slight increase in the summer peak load forecast and a reduction in the winter peak forecast. However, the latest adequacy assessment still identified that the system is least adequate during winter. Much of the western grid is summer peaking and it is important to continue to monitor adequacy for both winter and summer. This assessment confirms the need for this analysis. However, it is unlikely to shift the near-term results within the action plan period.