October 6, 2015

DECISION MEMORANDUM

TO: **Council members**

FROM: **Tom Eckman and Power Division Staff**

SUBJECT: **Release of Draft Seventh Plan for public review and comment**

PROPOSED ACTION: Staff recommends the Council approve the release of the draft Seventh Power Plan for public review and comment. Staff will edit and prepare the final document, with a target date for release to the public of October 20, 2015. Comment period to run until the close of business on December 18, 2015. Staff will schedule the necessary public hearings in all four states, schedule appropriate consultations, and make arrangements to receive written and oral comment on the draft plan.

SIGNIFICANCE:

Periodically reviewing and revising a regional conservation and electric power plan is one of the two main substantive planning tasks the Council undertakes under the Northwest Power Act. Providing for widespread public involvement and consultations with Bonneville, the Bonneville customers, other utilities, relevant state, local and federal agencies, Indian tribes, relevant non-government agencies and others on the formulation of the final power plan is also a key element of the Council's mission under the Act.

BUDGETARY/ECONOMIC IMPACTS:

There is little fiscal impact from the release of the draft power plan for public review, outside of the impact on the Council's budget of arranging for a broad public process for

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review of and comment on the draft plan. The final power plan will have an as yet uncertain impact on the Council's use of its staff resources and budget to help implement the plan, and an impact on the Bonneville budget as it takes actions to implement conservation measures and acquire resources consistent with the plan.

BACKGROUND:

The Council and staff have been working since mid-2014 on the development of the draft Seventh Power Plan. The time has come to release a draft power plan for public review and comment. The agenda for the October Council meeting includes an item scheduled for the end of the meeting on Wednesday, October 14, for the Council to decide on the release of the plan.

Over the past two months all twenty draft chapters have been made available for Council member review. The Power Committee and then the Council has focused most of its review and discussion recently on the draft Plan's Executive Summary (Chapter 1), Resource Strategy (Chapter 3) and Action Plan (Chapter 4). The latest versions of these chapters and of Chapter 2, a background assessment of the state of the northwest power system, are included in this packet. The versions of Chapter 1, 3 and 4 accompanying this memo reflect the results of the discussions by the Power Committee and the Council at the September Council meeting in Eagle, Idaho, and then the Power Committee's discussion by webinar on October 1.

At the end of this week (on Friday October 9), staff will make available to the members the latest versions of all 20 chapters (listed below) as well as all the supporting appendices for the draft plan. A few of the supporting appendices will be close to but not yet complete drafts by then, to be explained in detail in a memo that will accompany the draft appendices.

The Power Committee will meet again on October 12 and 13 to discuss what appear to be a handful of remaining issues with the key chapters, as well as any further discussions of other chapters and the appendices. Our expectation is that the Power Committee will then make a recommendation to the full Council to approve the draft Seventh Power Plan. Staff will make clear to the full Council what changes if any were made by the Power Committee in the final committee meetings.

In the discussion at the Council meeting itself, Staff plans to highlight the subject matter of each chapter, with more focused attention on the resource strategy, action plan, and executive summary chapters. The Council will entertain, discuss and resolve any proposals for further changes by the members, before moving to a decision to release the draft for public review.

The staff will need time to make the final edits and prepare the document for public release following the Council's decision. The target date for release of the draft Seventh Power Plan for public review is October 20, 2015. The target date for close of comment will be December 18, 2015. During that time the Council will take oral and written comments on the draft, hold public hearings on the plan in all four states, and engage in a series of consultations on the draft with key entities as called for in the Act.

Draft Seventh Power Plan chapters:

Chapter 1: Executive Summary (latest version included in the packet)
Chapter 2: State of the System (latest version included in the packet)

Part 1: Resource Strategy and Action Plan

Chapter 3: Resource Strategy (latest version included in the packet)
Chapter 4: Action Plan (latest version included in the packet)
Chapter 5: Bonneville's Loads and Resources
Chapter 6: Power Act Requirements and the Power Plan

Part 2: Demand and Price Forecasts, Existing Resources, and System Needs

Chapter 7: Electricity Demand Forecast
Chapter 8: Electricity and Fuel Price Forecasts
Chapter 9: Existing Resources and Retirements
Chapter 10: Operating and Planning Reserves
Chapter 11: System Needs Assessment

Part 3: New Resource Potential

Chapter 12: Conservation Resources
Chapter 13: Generating Resources
Chapter 14: Demand Response Resources

Part 4: Developing a Resource Strategy

Chapter 15: Analysis of Alternative Resource Strategies
Chapter 16: Analysis of Cost Effective Reserves and Reliability
Chapter 17: Model Conservation Standards and Surcharge Policy

Part 5: Other Plan Elements

Chapter 18: Coordinating with Regional Transmission Planning
Chapter 19: Environmental Methodology and Due Consideration for Environmental Quality and Fish and Wildlife
Chapter 20: Fish and Wildlife Program

CHAPTER 1: EXECUTIVE SUMMARY

[Boxed: Why We Have a Regional Power Plan

The Northwest Power and Conservation Council was authorized by Congress in 1980 when it passed the Northwest Power Act, giving the states of Idaho, Montana, Oregon, and Washington a greater voice in how we plan our energy future and manage natural resources.

Congress created the Council partly in reaction to the region's disastrous decision to build five nuclear power plants in the state of Washington in the 1970s. The decision was based in part on inaccurate Northwest electricity load forecasts. Only one of the plants, the currently operating Columbia Generating Station, was ever completed. Due to exorbitant cost overruns and low demand, the other four plants were abandoned or mothballed prior to completion.

Two of the unfinished plants were responsible for one of the largest bond defaults in the history of the nation, while the financing for the other three plants was backed by the Bonneville Power Administration. From 1978 to 1984, BPA was forced to raise its rates by 418 percent (adjusted for inflation) to pay for the cost of these plants. Even today, more than 30 years after the Northwest Power Act was enacted, BPA pays millions of dollars each year on debt service for two of the unfinished nuclear plants. Congress concluded that an independent agency, without a vested interest in selling electricity, should be responsible for forecasting the region's electricity load growth and determining which resources should be built.

One of the Council's primary responsibilities, along with the fish and wildlife program, is to write a 20-year, least-cost power plan for the Pacific Northwest and update it at least every five years. The plan is required to include several key provisions: an electricity demand forecast, electricity and natural gas price forecasts, an assessment of the amount of cost-effective energy efficiency that can be acquired over the life of the plan, and a least-cost generating resources portfolio. The plan guides Bonneville's resource decision-making to meet its customers' electricity load requirements.

In a decision that was ahead of its time, Congress concluded back in 1980 that energy efficiency should be considered a resource equivalent to generation and made it the first priority energy resource for meeting the region's future load growth. The Act includes a provision that directs the Council to give priority to cost-effective energy efficiency, followed by cost-effective renewable resources. In effect, for the first time in history, energy efficiency was deemed to be a legitimate source of energy, on par with generating resources. The rest is history. Since the release of the Council's first Northwest Power Plan in 1983, the region's utilities have acquired the equivalent of more than 5,900 average megawatts of electricity savings, enough to power five cities the size of Seattle.]

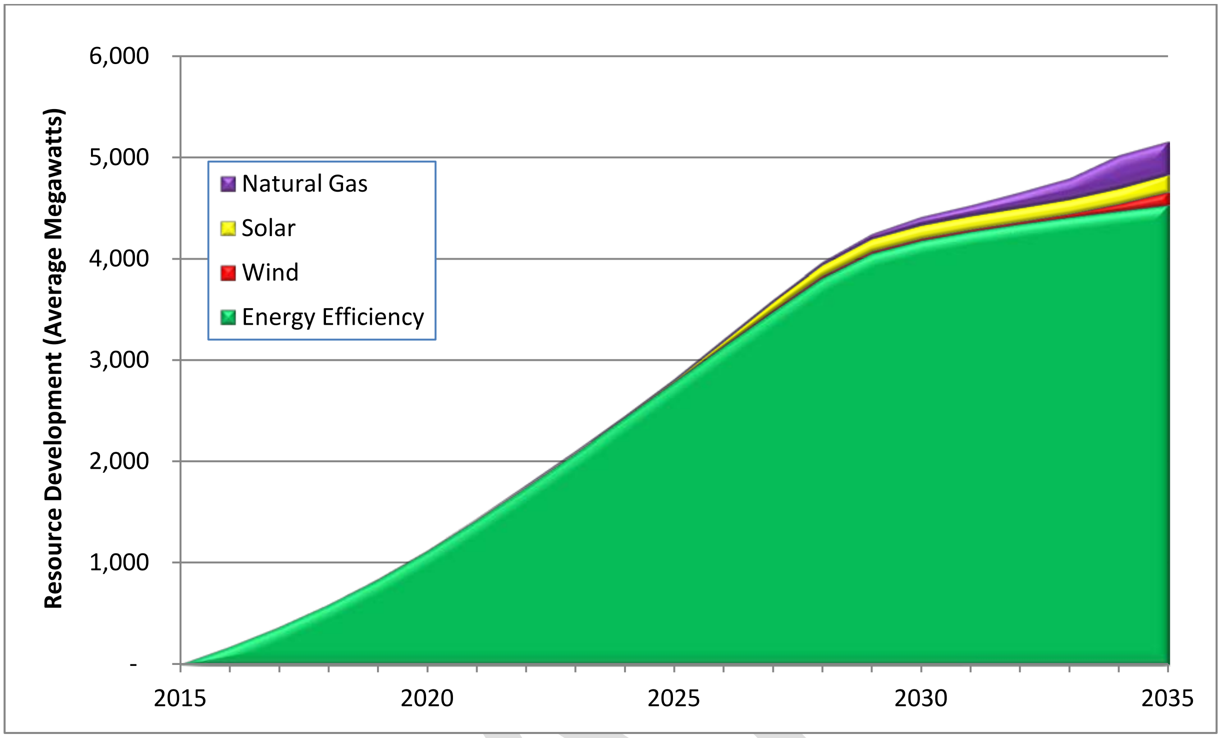
The Pacific Northwest power system faces a host of uncertainties, from compliance with federal carbon dioxide emissions regulations to future fuel prices, resource retirements, salmon recovery actions, economic growth, a growing need to meet peak demand, and how increasing renewable resources would affect the power system. The Council's Seventh Power Plan addresses these uncertainties and provides guidance on which resources can help ensure a reliable and economical regional power system over the next 20 years.

In developing its plan, the Council relies on feedback from technical and policy advisory groups and input from a broad range of interests, including utilities, state energy offices, and public interest groups.

The plan also recognizes that individual utilities, which have varying access to electricity markets and varying resource needs, may require near-term investments in resources to meet their adequacy and reliability needs. For example, some utilities face significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances, even if utilities deploy demand response resources and develop the energy efficiency called for in the plan.

Using modeling to test how well different resources would perform under a wide range of future conditions, energy efficiency consistently proved the least expensive and least economically risky resource. In more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2035. It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity. If developed aggressively, in combination with past efficiency acquisition, the energy efficiency resource could match the size of the region's hydroelectric system's firm energy output, adding to the Northwest's heritage of clean and affordable power. Figure 1 - 1 shows the composition of the Seventh Plan's Resource Portfolio.

Figure 1 - 1: Seventh Plan Resource Portfolio[1]



Acquiring this energy efficiency is the primary action for the next six years. The plan's second priority is to develop the capability to deploy demand response resources or rely on increased market imports to meet system capacity needs under critical water and weather conditions. While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional winter peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need. However, whether and to what extent the region should rely on demand response or increase its reliance on power imports to meet regional resource adequacy requirements for winter capacity depends on their comparative availability, reliability, and cost.

After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Similarly, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Combined with investments in renewable generation, as required by state renewable portfolio standards, improved efficiency, demand response resources, and natural gas generation are the principal components of the plan's resource portfolio.

[1] Figure 1 - 1 shows the average resource development across all 800 futures tested in the Regional Portfolio Model. Actual development, particularly of non-energy efficiency resources, will depend on actual future conditions.

A key question for the plan was how the region could lower power system carbon dioxide emissions and at what costs. The Council's modeling found that without additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035,[2] the result of retiring the Centralia, Boardman, and North Valmy coal plants by 2026; using existing natural gas-fired generation to replace them; and developing about 4,500 average megawatts of energy efficiency by 2035, which should meet all forecast load growth over that time frame.

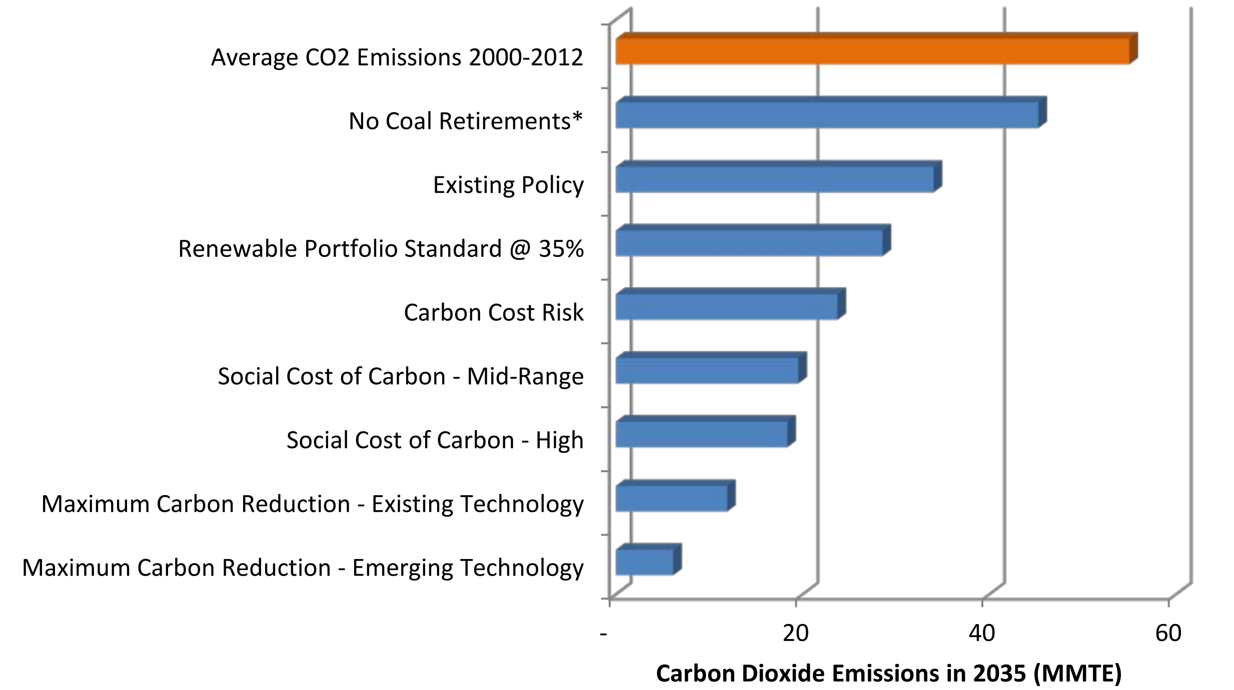
In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's carbon emissions limits, even under critical water conditions.

The Council also assessed alternative policies to further reduce emissions. With today's technology, carbon dioxide emissions could be reduced to about 12 MMTE, almost 80 percent below 2015 emissions (under average water conditions). This would require retiring all the coal generation serving the region, which is responsible for more than 85 percent of system emissions; retiring the most inefficient natural gas-fired generation; and acquiring additional energy efficiency and demand response resources. The estimated cost of doing this is nearly $20 billion over the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level. Reducing the region's power system carbon footprint below that level isn't technically feasible without developing new technologies.

Figure 1 - 2 shows the forecast average carbon dioxide emissions in 2035 under the various scenarios tested in developing the plan.

[2] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emissions could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001–2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

Figure 1 - 2: Forecast Northwest Power System Carbon Dioxide Emissions in 2035 by Scenario



* Scenario assumed that the announced retirements of Boardman, Centralia and North Valmy coal plants do not occur.

Investments to add transmission capability and improve operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate low and zero-emission resources into the existing power system. The Council also expects that there are small-scale resources available at the local level in the form of cogeneration or renewable energy opportunities. The plan encourages investment in these resources when cost-effective.

The plan encourages research in advanced technologies to improve the efficiency and reliability of the power system. For example, emerging smart-grid technologies could make it possible for consumers to help balance supply and demand. Providing information and tools to consumers to adjust electricity use in response to available supplies and costs would enhance the capacity and flexibility of the power system. Smart-grid development could also help integrate electric vehicles with the power system to aid in balancing the system and reduce carbon emissions in the transportation sector. Research on how distributed solar generation with on-site storage might affect system load shape is also encouraged.

Other resources with potential, given advances in technology, include geothermal, ocean waves, advanced small modular nuclear reactors, and emerging energy efficiency technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing variable generation like wind.

Developing these technologies is a long-term process that will require many years to reach full potential. The region can make progress through investments in research, development, and demonstration projects.

FUTURE REGIONAL ELECTRICITY NEEDS AND PRICES

Pacific Northwest regional loads, measured at the generation site, are expected to increase by between 2,200 and 4,800 average megawatts between 2015 and 2035. This translates to an average increase of between 110-240 average megawatts per year, or a growth rate of between 0.5-1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from about 30,000 - 31,000 megawatts in 2015 to around 32,000 - 36,000 megawatts by 2035. This equates to an average annual growth rate of between 0.4 - 0.8 percent.

Residential and commercial sectors account for much of the growth in demand. Contributing to this growth is increasing air conditioning load, new data centers, and growth in indoor agriculture. Also, summer peak electricity use is expected to grow more rapidly than annual energy demand. All of this growth in demand must be met by a combination of existing resources, energy efficiency, and new generation.

An important finding of the plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulation services will also need to be considered.

Requirements for within-hour flexibility reserves have increased because of the growing amount of variable wind generation in the region. While the plan doesn't foresee renewable resource development beyond what is required to satisfy existing state renewable portfolio standards, improved regional coordination could reduce the need for resources used to integrate existing renewables. For example, establishing energy imbalance markets could enable sharing resources reserved for integrating wind resources.

Wholesale electricity prices at the Mid-Columbia hub remain relatively low, reflecting the abundance of low-variable cost generation from hydro and wind, as well as continued low natural gas prices. The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas-fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Prices for natural gas have dropped significantly since reaching a high in 2008, and they're expected to remain relatively low going forward. Historically, natural gas prices have been volatile, so the plan uses a range of forecasts to capture most potential futures. The low price forecast range starts at

$3.50 per MMBtu in 2015 and declines in real dollars to $3.00 per MMBtu by 2035. This low-range case represents a future with slow economic growth, low gas demand, and robust supplies. The high price forecast range climbs to $10 per MMBtu by 2035. This forecast represents a future with high economic growth, high demand for natural gas, and a limited gas supply.

Recent promulgation of federal regulations that limit carbon emissions from both new and existing power generation are expected to increase the demand for natural gas. These higher natural gas prices result in higher wholesale electricity prices. Therefore, some of the futures used to develop this plan include a wide range of possible natural gas and electricity prices. Additional carbon regulations or costs could further increase electricity costs for consumers. While higher prices reduce demand, they also stimulate new sources of supply and efficiency and make more efficiency measures cost-effective.

RESOURCE STRATEGY

The plan's resource strategy provides guidance to the Bonneville Power Administration and regional utilities on resource development to minimize the costs and risks of the future power system. Timing of specific resource acquisitions will vary for each utility.

Energy Efficiency: The region should aggressively develop energy efficiency with a goal of acquiring 1,400 average megawatts by 2021; 3,100 average megawatts by 2026; and 4,500 average megawatts by 2035. Efficiency is by far the least expensive resource available to the region, avoiding the risks of volatile fuel prices and large-scale resource development, while mitigating the risk of potential carbon pricing policies. Along with its annual energy savings, it helps meet future capacity needs by reducing both winter and summer peak demand.

Demand Response: In order to satisfy regional resource adequacy standards, the region should be prepared to develop significant demand response resources by 2021 to meet additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources, the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. The Northwest's power system has historically relied on the hydrosystem to provide peaking capacity, but under critical water and weather conditions we'll need additional capacity to meet the region's adequacy standard.

Renewable Resources: Modest development of renewable generation will meet existing renewable portfolio standards. On average, renewable resources developed to fulfill state RPS mandates will contribute about 300 average megawatts of energy, or around 900 megawatts of installed capacity. While wind generation has been the dominant renewable resource developed in the region, lower costs for solar photovoltaic technology are expected to make it more competitive. As a result, compliance is expected to be met through both wind and solar PV systems. Because renewable resources lack dependable winter peak capacity, they require within-hour balancing reserves. The resource strategy encourages developing other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. The strategy also encourages research and demonstration of other potential renewable resources, such as geothermal, which has a more consistent output.

Natural Gas: Only low to modest amounts of new natural gas-fired generation is likely to be needed to supplement energy efficiency, demand response, and renewable resources, unless the region experiences prolonged periods of high load growth. However, increased use of existing natural gas generation is expected to replace retiring coal plants and meet carbon-reduction goals. Even if the region has adequate resources, individual utilities or areas may need additional supply for energy, capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

Regional Resource Use: Continue to improve system scheduling and operating procedures across the region's balancing authorities. These cost-effective steps will help minimize reserves needed to integrate renewable resources. The region also needs to invest in its transmission grid to improve market access for utilities, reduce line losses, and help develop diverse cost-effective renewable generation. Finally, the least-cost resource strategies rely first on regional resources to satisfy the region's resource adequacy standards. Under many futures conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost-effective and maintain regional power system adequacy, the region should develop the energy efficiency resources called for in the plan and replace retiring coal plants with only those resources needed to meet regional capacity and energy adequacy requirements. As stated earlier, after energy efficiency, increasing use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Developing new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in the plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore other sources of renewable energy, especially technologies that provide both energy and winter capacity; new efficiency technologies; new energy-storage techniques; smart-grid technologies and demand-response resources; and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or where unique opportunities emerge.

Adaptive Management: The Council will annually assess the adequacy of the regional power system to guard against power shortages. Through this process, the Council will be able to identify when conditions differ significantly from planning assumptions so the region can respond appropriately. The Council will also conduct a mid-term assessment to review the plan's implementation and ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Energy Efficiency

The dominant new resource in the Seventh Power Plan's resource strategy is improved energy efficiency. Figure 1 - 3 shows that under scenarios that consider carbon risk and those that do not, and even when natural gas and wholesale electricity prices are lower than expected, the region's net load after developing all cost-effective efficiency is basically the same over the next 20 years. In more than 90 percent of the 800 futures evaluated by the Council, across more than 20 different scenarios, the least cost resource strategy developed sufficient energy efficiency resource to meet all regional load growth through 2035. Indeed, even in the scenario (Lower Energy Efficiency) that assumed only energy efficiency costing less than short-term wholesale market prices would be acquired, all regional load growth through 2030 was met with energy efficiency. However, it should be noted that developing this lower level of efficiency increased regional power system cost by $14 billion or 16 percent higher compared to resource strategies that developed sufficient energy efficiency to meet all load growth through 2035 .

This is because improved efficiency is relatively cheap, it provides both energy and capacity savings, and it has no major risks. It's half what other resources cost, without the risk of volatile fuel prices or costs of carbon reduction policies. It also has a short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces the cost of, and risks to, the power system.

Figure 1 - 3: Average Net Regional Load After Accounting for Cost-Effective Energy Efficiency Resource Development

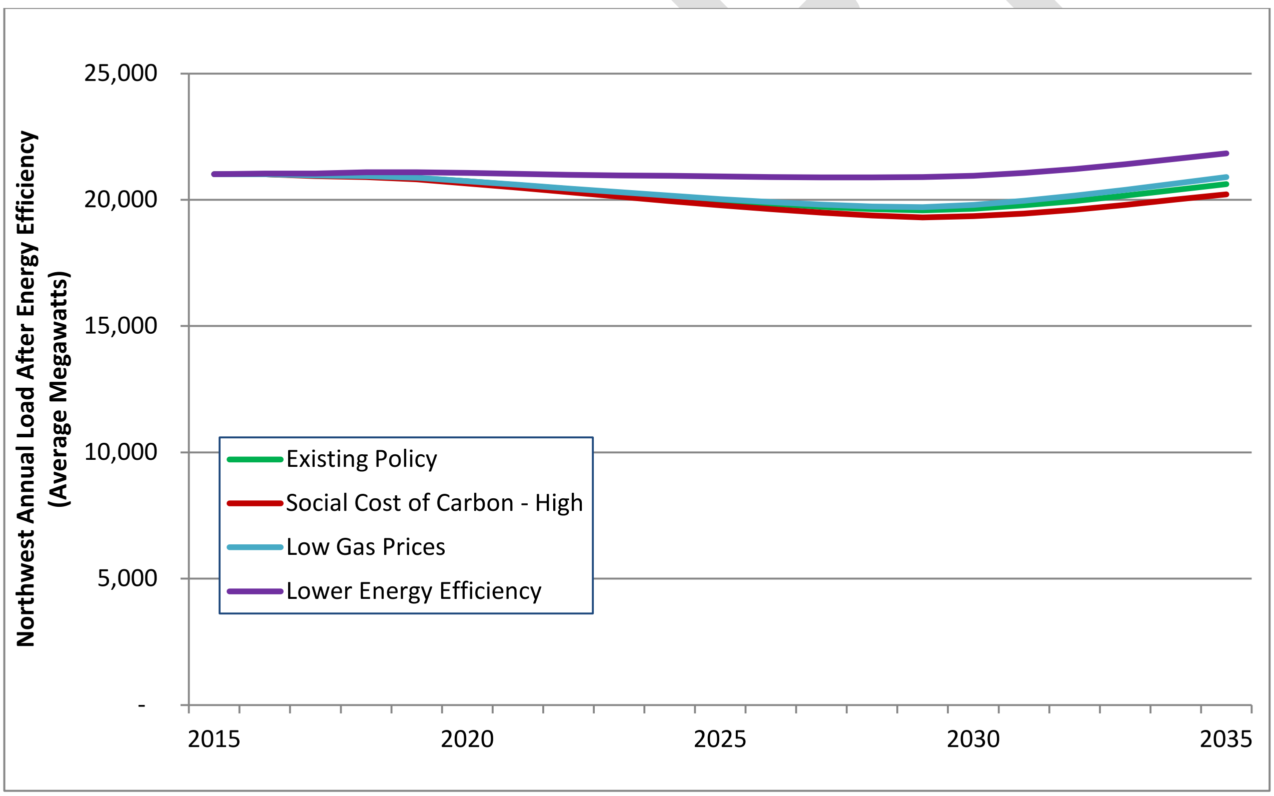


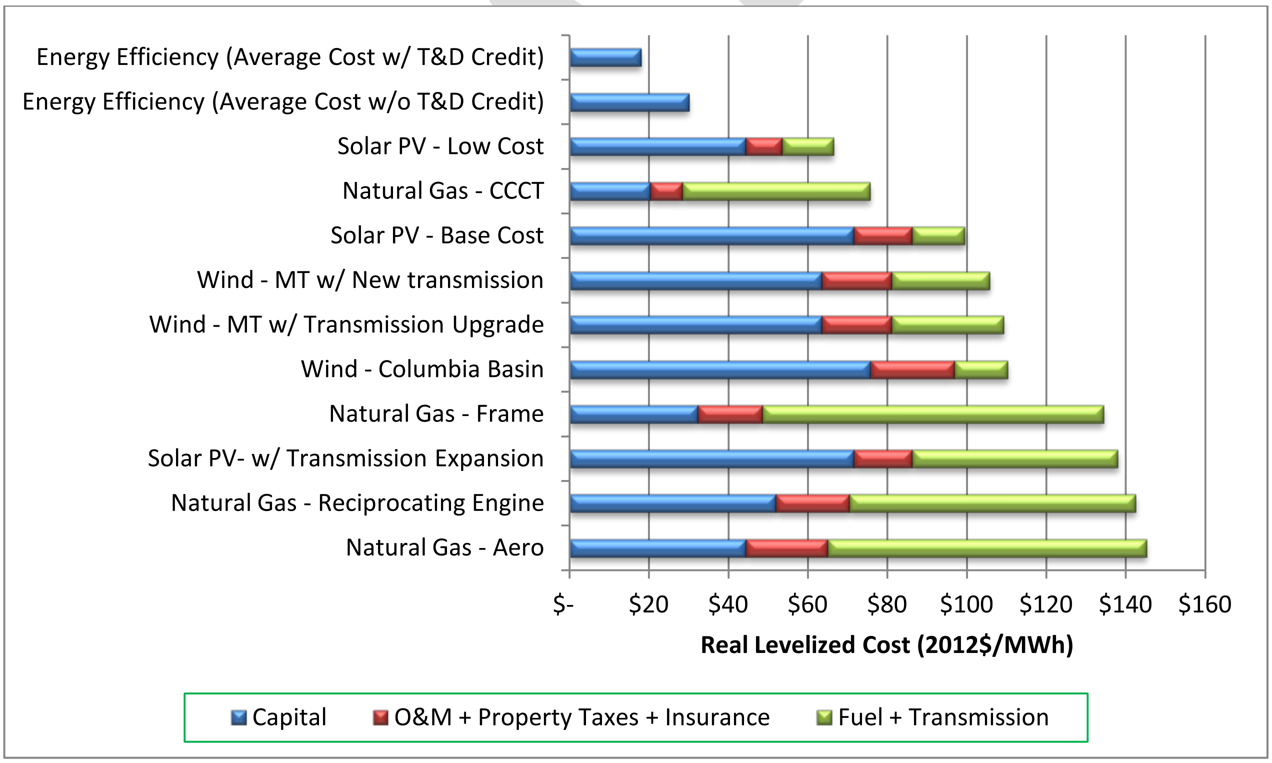
Figure 1 - 4 compares the average cost of the energy efficiency resources and the cost of generating resources considered in the plan's development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency's impact on the need to expand distribution and transmission systems. The higher cost ($30 per megawatt-hour) does not include these power system benefits.

The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility-scale solar photovoltaic systems is approximately $100 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour. Over time, the cost of utility-scale solar photovoltaic systems is forecast to drop to around $65 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity, since nearly 2,300 average megawatts energy efficiency savings are available below the average cost of $30 per megawatt-hour.

In the Council's analysis, additional resources provide insurance against an uncertain future. Efficiency improvements are particularly attractive as insurance because of their low cost and modular size. When the resources aren't needed, the energy savings from low cost energy efficiency resources can be sold in the market, paying for itself and then some.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency are found to be cost-effective even without carbon costs. If carbon reduction policies are enacted, efficiency improvements can help the region meet those goals. In all scenarios tested by the Council, the amount of cost-effective efficiency developed averaged between 1,300 and 1,450 average megawatts by 2021 and between 3,900 and 4,600 average megawatts by 2035.

Figure 1 - 4: Energy Efficiency and Generating Resource Cost Comparison



Demand Response

Demand response resources are voluntary reductions in customer electricity use during periods of high demand and limited resource availability. The plan's resource strategy uses demand response to meet winter and summer peak demands, primarily under critical water and extreme weather conditions. The strategy doesn't consider other possible applications of demand response--to integrate variable resources like wind for example.

The Council's assessment identified more than 4,300 megawatts of regional demand response potential. A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions.

In particular, demand response is the least expensive means to maintain peak reserves for system adequacy. Its low cost is especially valuable because the need for peaking capacity in the region largely depends on water and weather conditions. Under most scenarios, there was about a 20 percent probability that as much as 600 megawatts of demand response would be cost-effective to develop by 2021, and a 15 percent probability that as much as 1,100 megawatts would be cost-effective to develop by 2026.

Alternatively, the region could rely on external power markets to meet its winter peak capacity needs. In one scenario tested by the Council, the region relied more on external markets (Canada, California, and the Southwest) which greatly reduced the need to develop demand response. That scenario relaxed the Council's current assumptions about the availability of imports from out-of-region sources and from in-region market resources. Since that scenario's system cost and economic risk were lower than scenarios in which cost-effective demand response was acquired, the plan's resource strategy recommends that the Council's Resource Adequacy Advisory Committee reexamine all potential sources of imported energy and capacity to minimize cost and avoid the risk of overbuilding.[3]

Generation Resources

The Council analyzed a large number of alternative generating technologies. Each was evaluated in terms of risk characteristics, cost, and potential for improvements in its efficiency over time. In addition, resources were considered in terms of their energy, capacity, and flexibility characteristics, such as their ability to ramp up and down to accommodate variations in the output of wind and solar PV resources.

In the near term, generating technology options that are technologically mature, meet the emission requirements for new plants, and are cost-effective are limited in number. Improvements in the

[3] See Council Action Item 10.

efficiency and operation of natural gas-fired generation make it the most cost-effective option for now. While wind continues to be the primary large-scale, cost-effective renewable resource, decreasing costs for utility-scale and distributed-scale photovoltaic systems have made them cost-competitive sources of energy supply.

Other resource alternatives may become available over time, and the plan recommends actions to encourage their development, especially those that don't produce greenhouse gas emissions.

Since the adoption of the Sixth Power Plan, renewable resource development in the Northwest has increased significantly, particularly wind. By the end of 2014, wind capacity in the region totaled just more than 8,700 megawatts. However, only about 5,550 megawatts of that capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind capacity is presently contracted to utilities outside the region, primarily California. Wind now constitutes about 8 percent of the region's electricity supply, although expiring incentives and low load growth are expected to slow development over the next five years.

Current wind generation is estimated to provide about 2,400 average megawatts per year in the region. Wind resources with access to transmission are cost competitive with other generation. However, given current technology, wind can reliably provide about 5 percent of its nameplate capacity to meet peak loads. On a firm capacity basis, wind provides about 1 percent of the total system peaking capability.

The amount of additional renewable energy acquired *on average* in the least-cost resource strategies across scenarios didn't vary significantly, even in scenarios with high carbon cost risk. This is because the two economically competitive renewable resources available in the region, wind and solar PV, provide little or no winter peaking capacity. Partly because of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water conditions the region faces the probability of a peak capacity shortfall–again, because wind provides little winter capacity.

Renewable generation development in the plan is driven by state renewable portfolio standards. In the absence of higher standards, little additional renewable development is needed, even under scenarios where the highest social cost of carbon was assumed. The Council recognizes that additional small-scale renewable resources are available and cost-effective, and the plan encourages their development as an important element of the resource strategy. For example, Snohomish PUD recently completed the Youngs Creek hydroelectric project and Surprise Valley Electric Cooperative is developing the Paisley Geothermal Project, a low-temp geothermal power project in rural Oregon. There are many other potential renewable resources that may, with additional research and demonstration, prove to be cost-effective and valuable for the region to develop.

Natural gas is the fourth major element in the plan's resource strategy. It's clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near term. After energy efficiency, increased use of *existing* natural gas generation is the lowest cost option to reduce regional carbon dioxide emissions. It plays a major role in the least-cost resource strategies to reduce carbon dioxide emissions. Existing natural gas generation increases immediately in scenarios where carbon costs are imposed.

Across the scenarios evaluated, the optioning and completion of new gas-fired generating resources varied widely. New gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The plan's resource strategy includes optioning new gas-fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and only slightly higher in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are brought to construction in only a relatively small number of futures.

Across most scenarios, the probability of gas development is less than 10 percent by 2021. By 2026, the probability of constructing a new gas-fired thermal plant increases to almost 50 percent in scenarios where utilities are unable to develop demand response, and to over 80 percent in scenarios where existing coal plants and less efficient gas-fired generation are retired to lower carbon emissions.

While efficiency, demand response, and renewable resource development were fairly consistent across most scenarios, the future role of natural gas-fired generation varied depending on the specific scenario studied. The average build-out of new natural-gas fired generation over the 800 futures in most scenarios was less than 50 average megawatts of generation by 2026. Since the average nameplate capacity of a new combined-cycle combustion turbine assumed the analysis is 370 megawatts, this implies that "on average" only a single plant, operating less than 15 percent of the time is needed. By 2035, the average build out across all 800 futures was 300 to 400 average megawatts of annual output from new gas-fired generation--one or two additional plants. In the carbon-risk scenario, the amount of energy actually generated from new combined-cycle combustion turbines, when averaged across all 800 futures, is just 10 average megawatts, but close to 100 average megawatts in scenarios that assume no demand response resources are developed.

On the other hand, some utilities may need to develop new natural gas-fired generation, even if they deploy demand response and develop the plan's recommended efficiency. The regional transmission system hasn't evolved as rapidly as the electricity market, resulting in limited access to market power. Individual utilities may need within-hour balancing reserves or have near-term resource challenges.

The varying needs of individual utilities limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources or for the types of natural gas-fired generation. But it also underscores the value of a regional approach to resource development where resources are part of an interconnected system.

Regional Resource Use

The existing Northwest power system is a significant asset for the region. The Federal Columbia River Power System provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council doesn't directly model the sub-hourly operation of the region's power system, its models presume resources located anywhere in the region can provide energy and capacity services to any other location in the region, within the limits of existing transmission. This assumption minimizes the need for new resources to integrate renewable resources.

As envisioned in the Northwest Power Act, the benefits of the federal power system would be shared by all of the region's consumers. But achieving that vision has proved elusive; its desirability even questioned by some.

Several of the scenario analyses conducted for the plan highlight the benefit of using surplus generation for in-region energy and capacity needs; it avoids the need to build new resources and lowers total system cost. Under a wide range of future conditions, the least-cost resource strategy depends on the Bonneville Power Administration selling surplus generation in-region.

While by law regional utilities have first claim to Bonneville's surplus generation, the region's investor-owned utilities ultimately compete with out-of-region buyers for that generation. And for IOUs, investing in power plants offers the opportunity to increase shareholder value compared to buying power from Bonneville because they can earn a rate of return on capital investments and not on power purchases.

Under the current law, IOU access to Bonneville's surplus peaking capacity is limited to seven-year contracts.[4] If the IOUs and Bonneville do not enter into contracts for energy or capacity, it's likely that new generation will need to be built, despite the availability of energy and capacity resources from Bonneville to serve in-region demand. This will likely continue the trend that shows the electricity rates of IOUs increasing while public utility rates have remained flat over the past several years.[5]

CLIMATE CHANGE POLICY

Evolving climate change policies to lower carbon emissions from power plants was identified by stakeholders as one of the most important issues for the plan to address. Most recently, with the promulgation by the Environmental Protection Agency's final rules limiting carbon dioxide emissions from both new and existing power generating facilities, the goal of those policies became clearer. However, since states are charged with developing and implementing plans to comply with EPA's regulations, uncertainty still exists about specific approaches Northwest states will follow to satisfy the regulation.

Reduced carbon dioxide emissions can be encouraged through various policy approaches, including regulatory mandates (renewable portfolio standards, energy efficiency resource standards, emission standards) or carbon pricing policies, such as emissions cap-and-trade systems and emissions taxes. To date, state policy responses within the region have focused on renewable portfolio

[4] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, §508(b), (Supp. 1 1995) and Preference Act, Pub. L. 88-552, §3(c) (1994 & Supp. 1 1995).
[5] Between 2007 and 2013, the average revenue per kilowatt-hour sold by IOUs increased from 7.4 cents to 8.6 cents, while the average revenue per kilowatt-hour sold for public utilities remained unchanged at 6.1 cents.

standards and new generation emission limits. Oregon and Washington also have carbon reduction targets adopted by statute. While there have been both regulatory and carbon pricing policies discussed at the national level, the EPA's recently promulgated emissions limits are the most concrete policy option adopted.

The plan doesn't address whether carbon dioxide emissions should be reduced, by when or to what level. For now, these questions have been settled by EPA's regulations.[6] The questions for the plan are: What are the least-cost resource strategies to reduce carbon dioxide emissions and satisfy the federal emissions limits? And, what state (or regional) policies are likely to result in those least-cost resource strategies? The Council analyzed multiple carbon reduction scenarios, including three alternative carbon pricing policies and three regulatory policies.

The key findings from the Council's analysis of climate change policies include the following:

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035.[7] This reduction is driven by: 1) The retirement of three coal-fired power plants (Centralia, Boardman, and North Valmy) by 2026. These plants currently serve the region, but their retirement has already been announced; 2) Increased use of existing natural gas-fired generation to replace these retiring resources; and 3) Developing roughly 4,500 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame. If these actions do not occur, the level of forecast emissions is likely to increase. If these actions do occur, then the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions.

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, a nearly 80 percent reduction. Implementing this resource strategy would increase the present value average power system cost by nearly $20 billion (23 percent) over resource strategies that are projected to satisfy the Environmental Protection Agency's recently established limits on carbon dioxide emissions *at the regional level*.

- By developing and deploying current emerging energy efficiency and non-carbon emitting resource technologies, it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, about 50 percent below the level achievable with existing technology.

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[6] By "settled" the Council does not mean to imply that pending litigation over the EPA's regulations may not still alter those regulations. In this context, the Council simply means that in developing the plan it used EPA's draft and final regulations as the basis for its analysis of the cost and effectiveness of alternative carbon reduction policies.

[7] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emission could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges.

- Given the characteristics of wind and utility-scale solar PV and the energy and capacity needs of the region, policies designed to reduce carbon emissions by increasing state renewable portfolio standards are the most costly and produce the least emissions reductions.

- Imposing a regionwide cost of carbon, equivalent to the federal government's social cost of carbon highest estimate, results in lower forecast emissions, without significantly increasing the use of energy efficiency or renewable resources.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Columbia River Basin Fish and Wildlife Program is by statute incorporated into the Council's power plan. The fish and wildlife program guides the Bonneville Power Administration's efforts to mitigate the adverse effects of the Columbia River hydroelectric system on fish and wildlife. One of the roles of the power plan is to ensure the implementation of hydrosystem operations to benefit fish and wildlife while maintaining an adequate, efficient, economic, and reliable energy supply.

The hydroelectric operations for fish and wildlife have a sizeable impact on power generation. On average, hydroelectric generation is reduced by about 1,200 average megawatts compared to operation without constraints for fish and wildlife. Since 1980, the power plan and Bonneville have addressed this impact through changes in secondary power sales and purchases; by acquiring energy efficiency and some generating resources; by developing resource adequacy standards; and by implementing other strategies to minimize power system emergencies and events that might compromise fish operations.

In addition to operational changes, most of the direct and capital costs of the fish and wildlife program have been recovered through Bonneville revenues, and Bonneville has absorbed the financial effects of lost generation, resulting in higher electricity prices. The power system is less economical as a result of fish and wildlife program costs, but still affordable when compared to the costs of other reliable and available power supplies.

The future presents a host of uncertain changes that are sure to pose challenges to integrating power system and fish and wildlife needs: potential new fish and wildlife requirements; increasing wind generation and other renewables that require more flexibility in power system operations; conflicts between climate change policies and fish and wildlife operations; possible changes to the water supply from climate change that intensify conflict between fish and power needs; and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

Operations to benefit fish and wildlife have a significant biological value, and also a significant effect on the amount and patterns of generation from the hydrosystem. The Council encourages the federal action agencies to continue to monitor, evaluate, and report on the benefits and impacts to fish from flow augmentation and passage measures, including spill, and to work to revise and improve these evaluation methods as much as possible.

To address current operations and prepare for the challenges ahead, the Council will track changes and recommend actions by: annually assessing the region's power supply using its regional adequacy standard to ensure that events like the 2000-01 energy crisis, in which fish operations and power costs were affected, do not happen again; working with partners on its wind integration forum to help integrate wind generation into the power system; and completing a mid-term assessment of its power plan to measure our progress.

CHAPTER 2: STATE OF THE NORTHWEST POWER SYSTEM

Contents

INTRODUCTION

All planning processes start with information and assumptions about current conditions. This chapter summarizes the key assumptions regarding the state of the region that affected the Council's power system planning process or could potentially influence its implementation.

For example, the Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuels. Therefore, recent economic trends and energy prices represent a starting point for plan development.

The Northwest Power Act also requires the Council's power plan set forth a forecast of the region's power resources need, including that portion that can be met by resources in each of the priority resource categories identified in the Act. Since the power plan treats cost-effective energy efficiency as a priority resource for meeting future electricity demand, an assessment of its potential must reflect recent accomplishments and factors, such as the impact of codes and standards on future demand. Similarly, assessments of the need for resource development must account for the status of existing generating resources, including planned additions and retirements.

In addition to the state of the region's economy and status of conservation and generating resources, other factors such as environmental regulations, public policy and technology trends also influence plan development. For example, recently finalized federal carbon dioxide emission regulations and changes in California's regulations, such as the state's renewable portfolio standards, may alter energy prices and wholesale market supplies.

The following discussion describes the key assumptions used as the starting point for the Council's analysis. For many of these assumptions, while the current status is known, there is significant uncertainty about the future. That uncertainty creates risks that are addressed in the Seventh Power Plan's resource strategy, set forth in Chapter 3.

KEY FINDINGS

- Since 2011, regional employment has grown by over 500,000 jobs per year. During the last five years, gross state product for Idaho, Montana, Oregon, and Washington increased by $110 billion (2012$). The regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.
- While overall regional loads appear to be gradually returning to pre-recession levels, the increase has been slow. Regional electric loads finally returned to pre-recession levels in about 2014. On a weather-adjusted basis, total regional loads (excluding DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. However, since these loads are net of the energy efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, regional electricity efficiency savings totaled nearly 1500 average megawatts, exceeding the Sixth Power Plan's five-year goal of 1,200 average megawatts. Without those savings, regional loads, inclusive of the DSIs,

would have grown from 20,617 average megawatts in 2010 to 22,660 average megawatts in 2014, or by nearly 10 percent over five years.

- While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peaks have been increasing at about 0.4 percent annually. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.
- The Seventh Power Plan uses a range forecast of $3.95-$4.03 per million British thermal units (MMBtu) for 2015. However, the Council's forecast for future natural gas prices over the next twenty years spans a wider range; from a low of $3.14 per MMBtu to a high of $10.70 per MMBtu by 2035. This is a lower range of future gas prices than was used in the Sixth Plan.
- In June of 2014, the Environmental Protection Agency (EPA) released its draft regulations limiting carbon dioxide emissions from existing power generation facilities under section 111(d) of the Clean Air Act. These regulations were finalized in August of 2015 and call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. Along with releasing its final regulations for existing generation facilities, the EPA issued its final regulations limiting carbon dioxide emissions from *new* power generating facilities under Section 111(b) of the Clean Air Act. States have until 2018 to develop plans for complying with these new carbon dioxide regulations.
- Since the Sixth Power Plan, additional summer bypass spill requirements identified in the FCRPS Biological Opinion and included in the Council's 2014 Fish and Wildlife Program have decreased the hydroelectric system's capability. In addition, increasing reliance on the hydroelectric system to provide within-hour balancing needs[1] for wind generation has also diminished the system's peaking capability.
- In the Northwest, the retirements of three existing coal-fired plants serving the region have been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.
- Since the Sixth Power Plan was adopted in early 2010, three new natural gas-fired generating resources have been added in the region. The largest is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a reciprocating engine, in 2014 and is currently

[1] For more information on balancing needs see Chapter 9 and Chapter 16.

building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.

- From 2010 through 2014, about 4,100 megawatts of wind nameplate capacity was added to the region – about equal to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.
- Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources. The low spot market prices for power affect the region's utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.
- The region exceeded the Sixth Power Plan's five-year goal of 1,200 average megawatts of energy efficiency for 2010-2014 by 25 percent, achieving nearly 1,500 average megawatts of savings. Actual average utility costs for energy efficiency acquisitions have remained well below the cost of other types of new resources and wholesale market prices.
- The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking capacity and system flexibility are also emerging, expanding the focus of the region's planning and development of new resources to address these system needs in addition to energy. Since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, over 9,000 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand minute-to-minute; hence the need for system flexibility has become a concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.
- Conditions vary across the region and from utility to utility. Some have growing loads; others are flat or have lost large customers. Some have surplus resources and others face deficits. These differences affect utilities' incentives to acquire resources, including energy efficiency.
- Regional power supply planning matters are becoming increasingly linked with electric transmission and natural gas matters, requiring greater coordination.

STATE OF THE SYSTEM

Regional Economic Conditions

Employment and job creation in the Pacific Northwest remained sluggish during 2010 and 2011, growing from 6.11 million jobs in 2009 to 6.14 million jobs in 2011, adding just 150,000 jobs each year. Since 2011, however, employment has grown by over 500,000 jobs per year to 6.3 million jobs in the region in 2014. During the last five years, gross state product (expressed in constant 2012 dollars) for Idaho, Montana, Oregon, and Washington increased from about $560 billion dollars in 2010 to about $670 billion in 2014, a net increase of $110 billion. Based on these figures, the regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.

Sectors with economic growth during the last several years included durable goods manufacturing, information technology, health care, and technical services. Declining sectors included construction, mining, transportation, wholesale trade, and government services. Overall, these changes are consistent with an ongoing general structural shift in the regional economy towards less energy-intensive industries.

Forecasts used for the Seventh Power Plan showed the region's economy growing at a fairly healthy pace, consistent with long-term historical trends. The region's population is projected to grow to over 16 million by 2035 at an annual rate of 0.9 percent. Regional personal income, both in total and on a per-capita basis, has been on the upswing and is projected to continue, although at a slower rate. From 1989 through 2009 regional personal incomes grew by about 3.9 percent per year. The Seventh Power Plan forecasts personal income growth to average 2.9 percent per year over the coming two decades. Between 2015 and 2035, commercial employment is expected to grow at an annual rate of 0.9 percent, with total employment growing from 6.4 million in 2015 to about 7.7 million by 2035.

Economic conditions also vary within the region. For example, metropolitan areas with diverse economic bases have tended to fare better than rural areas, which have traditionally been more dependent on specific industries.

Electricity Demand

Between 2010 and 2014, regional electricity weather normalized loads, inclusive of the Direct Service Industries or DSIs (the large industrial customers historically served directly by Bonneville) increased slightly, growing from 20,617 average megawatts to 21,164 average megawatts. This five year increase of just under 550 average megawatts represents a total growth of just over 3 percent. If these large customer's loads are excluded, regional electricity loads grew from 20,111 average megawatts in 2010 to 20,454 average megawatts in 2014. This is an increase of 343 average megawatts of just under 2 percent growth over five years.

While overall regional loads appear to be gradually returning to pre-recession levels, the increase has been slow. On a weather-adjusted basis, total regional loads (excluding DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. Thus, regional electric loads finally returned to pre-recession levels in about 2014.

However, since these loads are net of the energy efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, the Council estimates, based on Bonneville, utility, Energy Trust of Oregon, and NEEA reporting, that regional electricity efficiency savings totaled nearly 1500 average megawatts. Without those savings, regional loads, inclusive of the DSIs, would have grown from 20,617 average megawatts in 2010 to 22,660 average megawatts in 2014, or by nearly 10 percent over five years.

While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peaks have been increasing at about 0.4 percent annually. At least two of the region's investor owned utilities, Idaho Power Company and Portland General Electric , have summer peak demands that are higher or nearly equivalent to their winter peak demands. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.

One of the newer segments contributing to demand has been data centers. Custom and mid-tier data centers have been attracted to the Pacific Northwest by financial and tax incentives, low electricity prices, and a skilled professional base. The Seventh Power Plan forecasts that electricity use by data centers could increase from their current level of 350 to 400 average megawatts to as much as 900 average megawatts by 2035. More recently, as a result of the legalization of cannabis production in Washington and Oregon, indoor agriculture is anticipated to contribute to between 100 and 200 average megawatts of increased electricity demand over the next twenty years. The Council's Seventh Power Plan also anticipates significant growth in electricity use in the transportation sector, forecasting that plug-in electric vehicles could add 160 to 625 average megawatts to regional electricity use by 2035.

Acting in the opposite direction are the anticipated impacts of new federal appliance, lighting and equipment standards. These new and revised federal standards are forecast to reduce future load growth by nearly 1500 average megawatts over the 20 year period covered by the Seventh Power Plan.

Natural Gas Markets and Prices

When the Council adopted its Sixth Power Plan in early 2010, market prices for natural gas had just dropped dramatically. U.S. average wellhead prices for natural gas, which averaged $8.24 per million British thermal units (MMBtu) in 2008, fell by more than half to $3.76 per MMBtu in 2009.

The rapid decline in natural gas prices was the result of the unanticipated, yet massive, transformation of the natural gas industry in the late 2000s. This change was driven by the sudden emergence of the huge potential to produce natural gas from shale formations using hydraulic fracturing techniques.

To a large degree, the natural gas price forecasts used in the Sixth Power Plan reflected the shale gas phenomenon. The forecasts were reasonably accurate during the first two years of the planning period. The plan's medium case forecast showed U.S. wellhead prices of $4.78 per MMBtu in 2010 and $5.07 per MMBtu in 2011. These forecasts turned out to be somewhat higher than actual market prices, which averaged $4.53 per MMBtu in 2010 and $3.91 per MMBtu in 2011.

Beginning in mid-2011, monthly wellhead gas prices fell fairly rapidly, reaching a low of $1.98 per MMBtu for the month of April 2012 before rebounding after that. Annual average prices averaged about $2.59 per MMBtu for 2012, significantly below the Sixth Power Plan's forecast of $5.10 per MMBtu.

The decline in market prices reversed and began to increase in April 2012, but since late 2014 prices began to decline due to a crash of world oil prices and glut of natural gas production from U.S. shale plays. Wellhead prices in 2014 averaged about $3.84 per MMBtu (in 2012 dollars). As of January 2015 the outlook for 2015 composite wellhead prices was $3.60 per MMBtu. Since January 2015, oil and natural gas prices have declined further. By September 2015, wellhead price declined to $2.70 per MMBtu (in 2012 dollars).

The U.S. Department of Energy's (DOE) Annual Energy Outlook 2015 forecasts Henry Hub gas prices will average about $3.63 per MMBtu during 2015. DOE forecasts that by 2025, Henry Hub gas prices will increase to $5.35 per MMBtu. By 2035, DOE forecasts natural gas prices will range from a low of $4.00 per MMBtu to a high of $8.64 per MMBtu. The Seventh Power Plan uses a range forecast of $3.95 to $4.03 per MMBtu in 2015. However, the Council's forecast for future natural gas price over the next twenty years spans a wider range; from a low of $3.14 per MMBtu to a high of $10.70 per MMBtu by 2035.

Increasingly, because of its low prices and apparent adequate supplies, natural gas-fired generation is displacing coal-fired generation. Coal to gas fuel switching is partly the result of environmental concerns, but it also reflects changed economics. In particular, it appears that lower market prices for natural gas are combining with higher market prices for coal to make natural gas-fired generating facilities more cost-effective.

Emissions Regulations and Impacts

Since the Council issued the Sixth Power Plan there has been extensive environmental regulatory activity that affects the electricity industry, much of it (but not all) relating to the production of electricity from fossil-fueled and especially coal-fired power plants. The list includes:

- Clean Air Act/national ambient air quality standards: The EPA has adopted more stringent standards for NO2, SO2, and particulate emissions, and proposed more stringent standards for ground-level ozone, all of which affect coal-fired power plants.
- Clean Air Act/regional haze rule: Continuing assessments and modifications of coal plants are required.
- Clean Air Act/ mercury and air toxics rule The U.S. Supreme Court recently struck down and remanded the rule to the lower appellate court for further review. Regardless of the appellate court's decision, the EPA is not likely to substantially alter the rule. Many coal-plant owners have already invested in compliance measures.
- Resource Conservation and Recovery Act/fly ash regulation: In 2015, the EPA issued a new final regulation for handling coal combustion residuals, including boiler bottom ash, fly ash (ash carried in the flue gas), boiler slag and products of flue gas desulfurization

- Clean Water Act/proposed revisions to effluent standards: In 2013, EPA proposed revisions to the standards for effluent from steam-electric power generation.. The purpose is to strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants, including mercury, arsenic, lead and selenium, from especially coal-fired generation. Final regulations are expected sometime in 2015.
- Clean Water Act/cooling water intake regulations finalized: The EPA recently issued final regulations establishing new requirements for cooling water intake structures in order to protect aquatic organisms.
- Clean Air Act / carbon dioxide emissions regulations: Most notably, EPA finalized regulations under Sections 111(b) and 111(d) of the Clean Air Act limiting carbon emissions from new and existing fossil-fueled power plants. The Section 111(d) regulations call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. The regulations are not yet effective (as of the end of September 2015), and will be the subject of extensive litigation.
- Nuclear Regulatory Commission regulations: In the wake of the Fukushima Reactor accident in Japan, the Commission is requiring upgrades to existing nuclear power generating facilities to better prepare for external events beyond ordinary design criteria.
- Clean Air Act/development of regulations to reduce fugitive methane emissions from the production and transportation of natural gas.
- Developing regulatory environment to protect eagles and other migratory birds from threats posed by the development and operation of wind and solar generating facilities.

Details about these regulatory efforts and their impacts are discussed elsewhere in the power plan, including Appendix I. Noteworthy here, is the collective effect of these environmental regulatory efforts, especially on the region's coal-fired power plants. In addition to the federal regulations, Northwest state policies on carbon emissions and other environmental impacts have all but eliminated construction of *new* coal-fired generating facilities as an option for meeting future resource needs. The issue for the regional power system is the effect of the announced retirements of *existing* plants, and the effect on the power system of state and federal policies that may lead to the retirement of other existing plants.

The U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2014 (AEO2014) Reference Case projects that a total of 60 gigawatts of capacity will retire by 2020, which includes the retirements that have already been reported to the EIA. Retirements are being driven in some cases by the compliance costs with new environmental regulations or the need to reduce green-house case emissions. Retirements are also being driven by the age of many existing plants and the need to refurbish them. In addition, as coal prices have risen over the last several years and natural gas prices have dropped, the operating cost advantage that coal has traditionally enjoyed has shrunk.

In the Northwest, the retirements of three existing coal-fired plants serving the region have been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025. In April of 2015 NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.

Analysis done for the Seventh Plan shows that as existing coal-fired power plants are shut down they are replaced by increased use of existing natural gas-fired generation, energy efficiency and demand response. These retirements produce significant net reductions in GHG emissions across the region. For example, regional power system carbon dioxide emissions are forecast to decrease from their current average level of about 55 million metric tons per year to around 34 million metric tons per year in 2035 after the retirement of the Boardman, Centralia and North Valmy plants.

The trend toward retiring existing coal-fired power plants across the U.S. is having other spillover effects on the Northwest region. As domestic coal-fired generation falls, coal producers are turning their attention to offshore markets as a way to continue production. This includes major companies in the Powder River Basin of Wyoming that have ramped up efforts to market their coal to Asian markets and are seeking to ship coal through the Northwest to export terminals near the coast.

Meanwhile, Northwest cities and counties that have climate policies or initiatives include: Seattle, Anacortes, Bellingham, King County, Olympia, and Whatcom County in Washington; Portland, Bend, Corvallis, and Multnomah County in Oregon; Boise, Idaho; and Bozeman, Helena, and Missoula in Montana.

Developments Affecting Power Imports from California

The Northwest and California are interconnected through AC and DC transmission interties with approximately 7,900 megawatts of maximum transfer capability, including 4,800 megawatts on the AC intertie and 3,100 megawatts on the DC intertie. Due to transmission loading on either end, the actual amount of transfer capability is closer to 6,000 megawatts and could be much lower if one of the lines is undergoing maintenance.

The two regions use these interties to share their power resources to help keep costs down. Because California's peak loads occur in the summer, that system normally has surplus capacity during the winter when Northwest loads are highest.

However, a number of changes have occurred in California since the Sixth Power Plan was adopted that have the potential to reduce the availability of winter imports to the Northwest and increase the need for new resources.

In May 2010, the California Water Resources Board adopted a statewide water quality control policy to meet the federal Clean Water Act's requirement to use the best technology available in power plant cooling processes. This is expected to force about 6,659 megawatts of older California generating plants into retirement by 2017. Other expected California resource retirements through 2017 are expected to reduce generation by an additional 1,030 megawatts.

Much of the retiring capacity in California is being replaced with modern gas-fired generation, including combined-cycle combustion turbines that are more fuel-efficient than the once-through-cooling plants and also have lower air emissions. Retiring capacity is also being replaced in California with fast responding simple-cycle combustion turbines that will provide capacity and help integrate renewables.

Also affecting the California market, both units at the San Onofre Nuclear Generating Station (SONGS), with about 2,200 MW of nameplate capacity, were taken out of service in January 2012 due to excessive wear in steam generator tubes. In June of 2013 the decision was made to retire the SONGS units.

Based on this information regarding California resources and considering California's load projections, the Council's Resource Adequacy Advisory Committee recommended limiting winter spot market imports to 2,500 megawatts. A review of historical south-to-north intertie transfer capability for winter months led the advisory committee to also recommend limiting the maximum south-to-north transfer capability to 3,400 megawatts.

Prior to the development of the Seventh Power Plan, the Council commissioned a study of market supplies available from California. The Energy GPS[1] study concluded that power surpluses from California during winter months are highly likely to exceed the south-to-north intertie transfer capability.

Another major factor is California's increasing reliance on renewable resources to meet its energy needs. In 2011, the California legislature passed a law requiring the state's utilities to serve 25 percent of their retail customers' loads with qualified renewable resources by 2016; this requirement increases to 33 percent by 2020. The law also established new policies limiting the use of renewable generation from outside California to meet the requirements. In September of 2015, the California legislature increased the minimum requirement to 50 percent by 2030. Many California utilities are already serving 20 percent or more of their customers' needs with renewable energy.

In order to meet these increasing renewable portfolio standards (RPS), California utilities have been increasingly turning to solar power development, as costs for photovoltaic systems have been falling rapidly. In 2014, solar power plants in California produced 10,555 gigawatt-hours (GWh) or 5.35 percent of the state's total electricity production. In August of 2015, California recorded its highest solar output to date, with 6341 megawatts of solar capacity contributing to meeting that states electricity needs. The large scale of solar development in California, however, presents significant challenges for power system operations and affects Northwest power markets.

Since the RPS are based on an energy metric (i.e. RPS resources must meet a minimum share of annual energy demand) and both solar and wind generation only operate a fraction of the hours in a year, the peak output of such systems is significantly (3 to 6 times) higher than the average output. As a result, integrating these resources into the existing power system requires that generation (usually gas-fired) must be ready to ramp-up or ramp-down to offset increases or decreases in wind and solar output. This gas-fired generation cannot be used to provide other types of reserves when it is designated for integration.

Separate from the physical integration challenges associated with increasingly larger amounts of wind and solar generation on the system, is the impact that these low-variable cost resources have on wholesale market prices. The spring and early summer months are when Northwest hydroelectric

[1] Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity", June 12, 2014, see www.nwcouncil.org/energy/resource/home/.

generation peaks due to spring runoff. This is also the period of the year when both wind and solar generation tend to be at their highest. The coincidence of the peak output of all three renewable resources, hydro, solar, and wind, can produce extremely low market prices due to supply far outstripping demand.

Unfortunately, wind resources contribute little to meeting peak demands and solar generation is typically much higher during summer months, which means less capacity would be available during the Northwest's peak season in winter. However, combustion turbines are used to provide within-hour balancing needs for renewable resources, some of their capacity might be available in winter for Northwest use. California is using summer-only demand response programs to help reduce its summer resource needs. This may reduce the amount of thermal generation peaking capacity available to serve Northwest loads in winter.

Wholesale Power Markets and Prices

For the Seventh Power Plan, three factors were identified as being likely to significantly influence future conditions in wholesale power markets: market prices for natural gas; potential new regulatory requirements for generating resources that emit greenhouse gases; and development of renewable resources to satisfy requirements of state renewable portfolio standards. A range of forecasts of wholesale power prices was then prepared using alternative assumptions about these factors.

Since the Sixth Power plan was adopted in early 2010, developments across all three of these areas have occurred that will directly impact future wholesale power market prices. First, the supply-side impacts of shale gas continue to unfold, causing market prices for natural gas to remain at low levels. Second, there are now federal regulatory mechanisms to reduce greenhouse gas emissions. Third, renewable resource development has added significant amounts of new generating resources whose output has very low variable operating cost. The combination of large amounts of new renewable resources in the Western wholesale power market and large supplies of hydroelectric generation, both of which have low variable operating costs, is producing very low spot market prices for wholesale power more often.

These and other factors (modest growth in demand for electricity) have caused actual spot market prices for wholesale power supplies during the last several years to be at or even below the low end of the range of forecasts used for the Sixth Power Plan. For example, actual spot market prices for wholesale power supplies bought and sold at the Mid-Columbia trading hub averaged about $26 per megawatt-hour during the period July 2014 through June 2015. In contrast, average prices for calendar year 2008 were 240 percent higher. The Council's Seventh Power Plan forecast for spot market prices ranges from an average of $29 per megawatt hour to an average of $60 per megawatt hour over the next twenty years.

The low spot market prices for power affect the region's utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.

Some of the region's hydro-based utilities have surplus power supplies at certain times of the year and depend on revenues from sales of their excess power into the wholesale market to keep power rates low. These utilities can experience significant revenue shortfalls and budgetary pressures when wholesale market prices are low. For hydro-based utilities, the impacts are magnified if the surplus energy they have to sell during the spring runoff coincides with surplus generation from other hydro systems, driving spot market prices to very low levels. This occurred during the period from April 2011 through July 2011, when spot market prices averaged well under $15 per megawatt-hour.

Conversely, utilities that do not have enough long-term resources to meet all of their customers' loads are net buyers in the short-term wholesale markets. When spot market prices are low, their power purchase costs are also low, reducing upward pressure on their retail electric rates. Relying on market purchases can be risky, as illustrated during the 2001 Western energy crisis. However, for now, these utilities are reaping the benefits of low market prices.

For all utilities, the depressed spot market prices for wholesale power are currently below the full cost of virtually any new form of generating resource.

Implementation of Bonneville Tiered Rates

In October 2011, the Bonneville Power Administration implemented tiered rates for its sales of wholesale power to the region's public utilities. Bonneville's tiered rates are designed to allocate the benefits of the existing federal power system and provide more direct price signals about the costs of new resources to meet load growth.

Under tiered rates, Bonneville's power sales are divided into two distinct blocks, or tiers. The rate for tier 1 power sales is based on the embedded cost of the existing federal power system. The tier 2 rate is set at Bonneville's cost to acquire power supplies from other sources. When a utility customer exceeds its allocation of tier 1 power, it can elect to buy tier 2 power from Bonneville, or it can acquire new resources itself. The alternatives include utility development of new energy efficiency and/or generating resources, as well as wholesale power purchases from third party suppliers.

Currently, the average cost of Bonneville's tier 1 power is roughly $32 per megawatt-hour. With the exception of energy efficiency, this is below the typical cost to develop new resources. Ninety of Bonneville's public utility customers are projected to exceed their tier 1 allocations in 2017 and thus will have to acquire additional resources.[2] The prospect of exceeding their tier 1 allocation in the future may already be influencing their behavior. There is anecdotal evidence that some utilities are taking action to avoid spot market purchases. So to a certain extent, tiered rates are achieving the intended purpose of providing more efficient pricing signals to Bonneville's utility customers.

However, prices for wholesale power purchased in the wholesale market remain relatively low, often below the cost of new resources or even below Bonneville's tier 1 rate. While spot market prices can be quite volatile, the addition of large amounts of new renewable resources with low variable operating costs has contributed to low spot market prices. To the extent that Bonneville or utilities

[2] http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/Formatted_Tables_RHWM_Process_2016_FINAL.xlsx

purchase power in the short-term market to meet their incremental resource needs, this mutes the tier 2 price signal.

Finally, there is also the matter of whether and how the price signal provided by Bonneville's tiered rates is passed through to each utility's retail electric customers. Retail customers are the end-users of electricity; their behavior affects load growth and load shapes. Utilities could influence their retail customers to reduce their total use of electricity and their peak demand by modifying their retail rate structures, by designing and executing energy efficiency and demand response programs, or a combination of these policies. So far, there is some anecdotal evidence that this is happening. For example, some of Bonneville's utility customers have added demand charges to their rate structures. Others have increased the portion of their revenues collected as monthly fixed charges and reduced the rate they charge per kilowatt-hour to minimize the impact of energy efficiency and distributed generation on overall revenue collection. Utility responses can be expected to develop over time, and are likely to mitigate growth in energy use and peak demand.

The Region's Utilities Face Varying Circumstances

Utilities across the region have experienced a variety of challenges and successes in the last few years. Some were expected and some are new, reflecting an ever-changing operating environment. As a result, the needs and incentives to acquire new resources also vary among the region's utilities.

Continued economic stagnation, particularly in the region's rural areas, has meant low overall load. Poor economic conditions have also triggered the loss of existing industrial loads as certain manufacturing facilities were shut down. For example, Snohomish County PUD lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In turn, this can create upward pressure on the utility's retail electric rates.

Meanwhile, a number of utilities have not yet exceeded their entitlements to purchase power from Bonneville at tier 1 rates. These utilities face lower near-term price signals than the cost of new resources. Consequently, their short-term economic incentives to acquire new energy efficiency resources at costs above the tier 1 rate are reduced.

On the other hand, the region has been a hotbed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. For example, Amazon has recently built data centers in the Umatilla Electric service territory, increasing their load substantially. Several of the Mid-Columbia PUDs have also seen significant growth as new data centers locate in their territory.

Certain utilities adding large new retail customers face the prospect of growing enough to become subject to higher state renewable requirements. These utilities may also exceed their entitlement to purchase power from Bonneville at tier 1 rates.

The Boardman coal-fired power plant will be retired in 2020 and Centralia and North Valmy coal-fired power plants will be retired in 2025. These planned retirements will eventually increase regional and individual utilities' needs for new resources, particularly among the region's investor-owned utilities.

As noted above, low spot market prices for wholesale power can be detrimental for utilities with surplus resources. However, low market prices can be beneficial for utilities whose long-term resources (including tier 1 purchases from Bonneville) are not sufficient to meet their retail customers' demands. Purchases from the short-term wholesale market can be a low-cost source of power to help fill these utilities' deficits. This can create an economic incentive to rely on short-term market purchases as an alternative to making long-term investments in higher-cost new resources.

Small and rural utilities face special challenges in acquiring efficiency resources. These include the absence of economies of scale enjoyed by larger utilities in urban areas and less availability of qualified contractors. Approaches to acquire energy efficiency must be tailored to meet their unique needs. Pursuant to actions recommended in the Sixth Power Plan, Bonneville, NEEA, and the Council's Regional Technical Forum have established work groups and policies to address those needs. In addition, Bonneville also established a low-income working group to address the needs of those consumers in the region who lack the means to participate in utility programs but may have significant opportunities for energy efficiency in their residences.

Energy Efficiency Achievements

The Sixth Power Plan identified a range of likely energy efficiency resource acquisition during 2010 to 2014 of between 1,100 and 1,400 average megawatts. Within this range, the plan recommended setting budgets and taking actions to acquire 1,200 average megawatts of savings from utility program implementation, market transformation efforts, and codes and standards.

The plan estimated that the region would ramp up its pace of acquisition during the initial five-year period. Despite a sluggish economy, which limited new building construction and equipment replacement, the region's overall acquisition exceeded the Council's ramp-up expectations surpassing the high end of the expected savings range.

Over the first five years of the Sixth Power Plan, the region's utilities, the Bonneville Power Administration, Energy Trust of Oregon, and Northwest Energy Efficiency Alliance (NEEA) acquired nearly 1,300 average megawatts of efficiency. In addition to the savings acquired by the utilities, Bonneville, Energy Trust, and NEEA, all four states recently adopted new building energy codes. NEEA estimates that improvements in state energy codes have produced 18 average megawatts of savings over the last five years.

Another significant contributor to savings in recent years is due to the adoption of minimum efficiency standards for energy-using products. Since 2009, the federal Department of Energy has issued final product standards for more than 36 products ranging from refrigerators to utility transformers. Some of these standards took effect in between 2010 and 2014, producing about 50 average megawatts of additional savings during that period. States have also begun to adopt minimum standards for products not covered by federal standards, such as battery chargers.

In addition, consumer uptake of efficient products, outside of direct utility-funded programs, has been particularly strong for lighting equipment since 2010. In part, this consumer uptake is due to prior utility programs pushing efficient products into markets and in part it may be due to consumer preference. Together, minimum product standards and consumer uptake added about 220 average megawatts of documentable savings outside of direct utility-funded programs in the 2010 to 2014 period.

All told, between utility-funded programs, state codes and standards, federal standards, and consumer uptake, the region captured about 1500 average megawatts of savings during 2010-2014, achieving 125 percent of the Sixth Power Plan goal and surpassing the high end of the expected savings range.

Demand Response Activities

The two regional utilities with the most experience in acquiring and using demand response, PacifiCorp and Idaho Power, have continued to expand and refine their programs. Both are now exercising control over 700 megawatts of their in-region peak loads. While other regional utilities have not acquired DR to this extent, some are gaining experience with it. PGE has contracted for 28 megawatts of DR in the industrial and commercial sectors, and continues to conduct pilot programs, currently focusing on the residential sector. BPA continues to explore pilot programs and demonstration projects in cooperation with its utility customers, Energy Northwest and EnerNOC, testing the potential of DR resources' capability to provide winter peak reductions, within-hour balancing of variable energy resources, and strategic transmission relief. BPA has also arranged for 35 to 100 megawatts of contingent reserves to be provided by ALCOA's aluminum smelter.

Puget Sound Energy and Avista have both conducted demand response pilot programs in the recent past. However, while both companies have identified the technical potential of demand response and evaluated DR as part of their resource planning process, neither of these utilities is currently acquiring DR resources.

Renewable Resources Development

Since the adoption of the Sixth Power Plan, renewable generating resources development has increased significantly. This development was prompted by Renewable Portfolio Standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region – about equivalent to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

Snohomish PUD began producing power from its 7.5 megawatt Youngs Creek run-of-river hydro project in October 2011. It is the first new hydropower plant to be built in Snohomish County since the early 1980s.

As noted above, until recently, a considerable amount of wind power was developed in the Northwest for sale to California utilities subject to that state's renewable portfolio standards. However, it is expected that few additional Northwest wind resources will be built for this purpose, despite California having raised its RPS requirement to 33 percent by 2020, and recently increased to 50 percent by 2030. The reason is that restrictions imposed by the California legislature in 2011 effectively block further imports from outside the state to meet RPS needs. Another contributing factor is that costs for solar photovoltaic generation have come down to the point where in-state solar is increasingly competitive with imported wind generation.

In terms of developing renewable resources to meet Northwest RPS needs, actual results have been generally consistent with the Sixth Power Plan. The Sixth Power Plan's resource strategy incorporated projections that the region would add over 1,400 average megawatts of renewable resources over 20 years to meet renewable portfolio standards that the states have enacted. The new renewable resources were anticipated to be almost wholly wind power.

Notable differences between the Sixth Power Plan and this Seventh Power Plan in terms of renewables development include the following:

1. While the Sixth Plan assumed renewable resources would be developed to meet 95 percent of RPS targets, recent experience suggests most utilities are actually achieving 100 percent (and sometimes more) of their target levels several years in advance of the requirement.
2. Construction of renewable resources to serve the California market is expected to slow, if not end completely.

The quantity of reserves on the Bonneville system to provide balancing services has remained relatively constant, even as wind on the system has increased. Nevertheless, the ability of the hydro system to provide balancing services varies, and at times it has dropped to near zero. At such times, wind generation or delivery schedules are limited to maintain the power system supply and demand balance. This has occurred primarily during very high flow spring months when the hydro system must pass prescribed flow levels for flood control and environmental requirements constrain the ability to pass water over spillways. This occurs when the generation level is high and relatively fixed.

In addition to the limited ability to provide balancing services during these oversupply events, Bonneville has at times had trouble finding markets for its power at acceptable (non-negative) prices. It implemented a controversial policy of displacing wind resources with hydro generation under negative market price conditions when hydro turbine generating capability is available and dissolved gas levels rise above state mandated caps.

The Council convened an Oversupply Technical Oversight Committee to recommend actions to reduce oversupply events. The committee developed a number of recommendations to more cost-effectively deal with oversupply events. The region continues to develop methods to integrate wind generation into the grid and the last Bonneville oversupply event was in 2011.

Meanwhile, as noted, costs for solar photovoltaic generation have dropped dramatically during the last several years. In the Sixth Power Plan, the Council estimated that solar photovoltaic generation would cost about $254 per megawatt hour. The Seventh Power Plan's estimated cost of solar photovoltaic generation located in Southern Idaho now ranges from as low as $66 to $99 per megawatt hour – a 60 to 75 percent cost reduction. Although solar potential is lower in much of the Northwest compared to other areas such as the Southwest, the economic and commercial viability of solar power has improved such that in the best Northwest sites (e.g., Southern Idaho), the levelized cost of solar production is lower than the levelized cost of wind generation.

Additions and Changes to Fossil-Fueled Generating Resources

The Sixth Power Plan's resource strategy called for phased optioning (siting and licensing) of new natural gas-fired generation facilities, including up to 650 megawatts of single-cycle combustion turbines and 3,400 megawatts of combined-cycle combustion turbines. The Sixth Power Plan's resource strategy also recognized it may be necessary to develop additional natural gas-fired generation when individual utilities need to address local capacity, flexibility, or energy needs not captured in the plan's region-wide analysis.

Since the Sixth Power Plan was adopted in early 2010, the largest new natural gas-fired generating resource added in the region is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a reciprocating engine, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.

During the last couple of years, some utilities have issued requests for proposals (RFPs) to acquire generating resources. An informal survey identified RFPs calling for over 3,100 megawatts of conventional generating resources, including base load, intermediate, and peaking resources. It is likely that some of their needs will be met by uncommitted power plants in the region.

For example, in late July 2012, Puget Sound Energy (PSE) and TransAlta announced a power sales contract that will supply base load generation from the Centralia coal-fired plant to PSE from December 2014 to December 2025, including 380 megawatts of coal-fired generation during the period December 2016 to December 2024.

After the Sixth Power Plan was issued, planned retirements of several generating resources were announced, including closure of the 550 megawatt Boardman coal plant in 2020 and closure of one 670 megawatt unit at the Centralia coal plant in 2020 and the other 670 megawatt unit in 2025. More recently the retirement of the 522 megawatt North Valmy coal plant in Nevada by 2025 was announced as well as the closure of the 172 megawatt J.E. Corette coal plant in Montana in 2015. The replacement of the energy and capacity lost as a result of these retirements is addressed in the Seventh Power Plan's resource strategy.

Hydropower System Operational Changes

The operational flexibility and generating capability of the Columbia River Basin hydroelectric system has been reduced since 1980 primarily due to efforts to better protect fish and wildlife. Over the past thirty years, the pattern of reservoir storage and release has shifted some winter river flow back into the spring and summer periods during the juvenile salmon migration period. In addition, minimum reservoir elevations have been modified to provide better habitat and food supplies for resident fish. The results of these changes have reduced the hydroelectric system's firm generating capability by about ten percent or by roughly 1,100 average megawatts. Since about 1995, the region's hydroelectric system's peaking capability has dropped by about 5,000 megawatts. Most of these changes have occurred between 1980 and the early 2000s. Since the Sixth Power Plan, additional summer bypass spill requirements identified in the FCRPS Biological Opinion and included in the Council's 2014 Fish and Wildlife Program have further decreased the hydroelectric system's capability. In addition, increasing reliance on the hydroelectric system to provide within-hour balancing needs[3] for wind generation has also diminished its peaking capability.

Shifting Regional Power System Constraints

In most of the other regions of the country, power system planning and development tend to focus on making sure that resources will be adequate to meet customer demands during relatively short extreme peak periods such as cold winter or hot summer weather events. In those regions, if resources are adequate to meet peak demands, they are usually sufficient to meet energy needs throughout the year. This is largely because other regions mainly rely on fossil-fueled and nuclear power, whose fuel supplies are relatively abundant and controllable. These systems are described as capacity constrained.

In contrast, the Pacific Northwest power system has traditionally been characterized more as energy-constrained. The main reason for this has been our region's abundance of hydroelectric generation. Unlike other forms of generation that consume fossil or nuclear fuels, the amount of energy the hydro system can produce fluctuates with supplies of water, which in turn depend on uncertain streamflows and limited reservoir capacities. As a result, in the past, the Northwest power system had more than adequate resources to meet peak demands. When constraints occurred, they were usually related to the availability of energy across longer periods of time.

However, during the last decade or so, the Northwest power system has gradually become less energy constrained and more capacity constrained. New resources, partly to meet load growth and partly to meet state-mandated renewable portfolio standards, are driving this shift, and as these new resources have been added, hydro generation's share of the region's total portfolio of resources has gradually declined.

For example, since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, over 9,000 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand and resources minute to minute; therefore, the need for system flexibility has become a growing concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements. The mechanism for accessing this capability; however, may not be available to all Balancing Authorities depending on market structure/availability.

Persistent low spot market prices for wholesale power are another sign that the Northwest power system has become less energy-constrained. To a degree, low power prices are the result of low

[3] For more information on balancing needs see Chapter 9 and Chapter 16.

prices for natural gas. However, they also reflect direct and ongoing competition between hydro generation and newly-added wind power. Both have very low incremental operating costs and during periods of strong runoff and robust winds, competition between the two can drive spot market prices to very low levels.

The region is making progress developing a variety of additional mechanisms to integrate wind power, including recent activity in the region and California regarding the establishment of a sub-hourly energy imbalance market. Improving market liquidity across balancing authorities is likely to have a positive effect on the region’s needs for peaking capacity and flexibility.

Looking forward, it is apparent that regional power planning needs to take into account shifting constraints on the system. These include reduced constraints for energy and increasing constraints for peaking capacity and for system flexibility.

Power and Transmission Planning

Momentum to coordinate power resource and transmission system planning activities has grown in the last few years. Several forces are driving this, including:

- Renewable resources development which, because of their variability, affect power markets and system operations
- Changes to generation and/or transmission facilities in one area can often cause impacts in other areas
- Recent major outages that have cascaded across multiple systems, including a widespread event that occurred in the Southwest in September 2011
- More stringent and comprehensive reliability standards
- A growing need for new transmission facilities
- Increasing costs to transmit and integrate renewable and other new generating resources

In response, various activities and initiatives have been undertaken:

- Federal Energy Regulatory Commission (FERC) Order 1000 requiring transmission planning and cost allocation
- Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC)
- Changing roles for WECC (pending division into two organizations)
- Planning activities of Columbia Grid, Northern Tier Transmission Group (NTTG), California Independent System Operator
- Activities to restructure the market and develop new practices (diversifying area control management, investigating energy imbalance markets)

Historically, a major focus for transmission planning was analyzing power flows under peak loading conditions and during contingency events. More recently, attention has broadened to include simulating power flows during various market and operating scenarios. As a result, production simulation models similar to those used for integrated resource planning are also being used for transmission system planning studies. Transmission studies also require assumptions about what new resources will be added by type, quantity, and location.

Past Council power plans have addressed various transmission issues, but intra-regional transmission system constraints and alternative approaches to address such constraints have not been extensively analyzed.

Given the changing situation, regional power and transmission system planning should coordinate by:

- Including the intra-regional transmission constraints and major planned transmission projects in the Council's power system analyses
- Including the Council's power plan assumptions, forecasts, and results in transmission planning studies
- Cross-checking for consistency of major inputs to power and transmission planning studies

The Council continues to work with ColumbiaGrid to identify areas for coordination and to improve coordination with other organizations, including WECC, TEPPC, and NTTG.

Power and Natural Gas System Convergence

During the last decade, natural gas-fired generation has become the leading fossil-fueled resource, both in the Pacific Northwest and nationally. Over 5,900 megawatts of gas-fired generation has been added in the region since 2000. Gas-fired generation is relatively flexible and can be used to supply energy and capacity, as well as help balance variable output from other resources, including wind power.

As gas-fired generation has become a bigger part of the power system, it has also become a significant source of demand on the existing natural gas pipeline and storage system. This has raised questions about the adequacy of the natural gas system to serve direct end users and to fuel electric generation. Challenges resulting from increased use of gas-fired generation which are being addressed in regional and national forums include :

- Different scheduling and operating practices used by the electric and natural gas industries
- Gas-electric communication and coordination during extreme weather conditions or outage events
- Planning and development of pipeline and underground storage infrastructure
- Access to pipeline and storage facilities for local distribution companies and electric generation
- The impact of rapid swings in use of natural gas for generation to balance variable energy resources like wind power

In response to these issues, several activities have been launched, including the following:

- The Pacific Northwest Utilities Conference Committee and the Northwest Gas Association formed a joint power and natural gas planning task force; this has established strong dialog and closer coordination
- During the summer of 2012 and in February 2013, the Federal Energy Regulatory Commission held a series of technical conferences on gas-electric coordination

- The Northwest Mutual Assistance Agreement was revamped and expanded to improve utility industry responses to emergency conditions
- A committee of the Western Interstate Energy Board was convened to assess gas-electric issues in the Western U.S., including planning to ensure gas infrastructure remains adequate

To date, the results of these activities have identified various opportunities to improve communication by the electric and natural gas industries. As natural gas continues to be used to generate electricity, further attention to power and gas convergence will likely be needed.

Fortunately, it is becoming apparent that our region's natural gas infrastructure is relatively robust when compared with other regions. For example, the Northwest has more underground gas storage capacity than some other regions. In addition, deliverability from interstate pipelines has not been significantly impacted by regional shifts in gas production due to rapid growth in shale gas production, as may be occurring elsewhere. Further, the great majority of natural gas-fired generating facilities in the Northwest have firm pipeline capacity rights, fuel-switching capability or both.

[a red-lined revised version of the CRT section for Chapter 2 from JS and TE on 10/6, using Tom Karier's version of the morning of 10/5 as a base – a clean version of this comes after]

SEE BELOW

Columbia River Treaty Review

One of the uncertainties with the Pacific Northwest power supply over the next decade is the fate of the Columbia River Treaty, the agreement with Canada executed in the early 1960s. Under the treaty Canada agreed to build three projects in the portion of the Columbia River in British Columbia that store more than ~~under which~~ 15 million acre of feet of Columbia River runoff. BC Hydro manages the treaty storage projects ~~is stored in reservoirs in British Columbia and managed~~ primarily for flood control and power generation optimization. The US delivers to Canada a share of the downstream power benefits known as the Canadian Entitlement, calculated by a method set forth in the treaty and an accompanying protocol. In 2015 this amounted to X MWh of energy and Y MW of capacity, often delivered during the highest load hours of the month.

Under the treaty, the annual assured flood control operations ends in 2024, to be replaced with a “called upon” flood control operation which has yet to be specified in any detail. Unless the two nations agree to a new arrangement for flood control, there is a good chance flood control operations at both the U.S. and Canadian storage projects will change significantly after 2024, affecting generation patterns as well.

The treaty’s provisions governing coordinated power operations do not change automatically in 2024. ~~But e~~Either nation may terminate the t~~T~~reaty beginning in 2024, with at least 10 years’ notice. Continuing the treaty without any change in the power provisions retains the certainty ~~and value~~ of the coordinated power operation and the flexibility under the treaty to enter into annual supplemental agreements to modify flows to meet non-power needs. But continuing the treaty provisions would also mean continuing with power operations and methods for calculating downstream power benefits that were designed in the 1960s and appear increasingly out-of-date with current power system operations and with modern perspectives for assessing the value of the treaty operations.~~, including the ordinary operations that add energy and capacity to meet winter needs, as well as the ability to coordinate proportional drafting of upriver reservoirs to meet summer needs in low-flow years. But it also means continuing what seems to be an increasingly out-of-date method for calculating Canada’s share of the downstream power benefits known as the Canadian Entitlement. It has been noted that the ongoing benefits of treaty operations no long align with the Canadian entitlement calculation and although the United States has more than paid for the construction of the Canadian dams, these annual payments continue. The Treaty also keeps the power operation provisions from the 1960s that, while not completely inflexible, can make it difficult to coordinate operations with today’s regional and west-wide power system.~~

~~Termination would bring obvious benefits to the U.S. by being able to retain both the energy and capacity currently delivered to Canada. In 2015 this amounted to X MWh of energy and Y MW of power, usually delivered during the highest load hours of the month. While termination may cause the U.S. to lose the certainty of coordinated operations and incidental flood risk management benefits from the winter power draft,~~

~~Canada would lose an extremely valuable portfolio of carbon free power. It is possible to imagine a modernized treaty that integrates ecosystem needs and leaves both countries better off than having no Treaty.~~

Any consideration or discussion about changes in the treaty related either to flood control or power or both – rather than termination or continuation without change – raises other issues as well, including whether and how to consider fish and wildlife and other ecosystem considerations in the cooperative management of these treaty storage projects.

[following is moved to below] ~~The main point for this assessment is that the region is heading into a period of uncertainty after many decades of relative certainty and international cooperation. A modified cooperative arrangement that continues to allow for the Canadian storage projects to be operated in a coordinated fashion but also meets the needs of the 21st century is likely a far better scenario than either continuing or terminating the treaty. But the treaty itself does not allow explicitly for modification, and the process to revise a cooperative arrangement is challenging.~~

The Bonneville Power Administrator and the Corps of Engineers' Northwestern Division Engineer (together the designated U.S. Entity under the treaty) joined with other federal agency, state, and tribal personnel from 2011-13 to review the current treaty and recommend changes. Out of this effort came the "U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," delivered to the State Department in December 2013. The US. Entity regional recommendation recommended neither termination nor the status quo, calling instead for the two nations to negotiate a "modernized" treaty with modifications that respond to the current issues with flood control, coordinated power operations, ecosystem needs, and the calculation and sharing of benefits. The Province of British Columbia led a similar review, and produced what it called its "Columbia River Treaty Review: B.C. Decision" at the same time. Neither the U.S. State Department nor Foreign Affairs Canada have responded officially to the regional recommendations. The NW region is waiting for confirmation from the U.S. State Department that they are ready to begin negotiations which could commence within the year.

[moved from above] The main point for this assessment is that the region is heading into a period of uncertainty after many decades of relative certainty and international cooperation. A modified cooperative arrangement that continues to allow for the Canadian storage projects to be operated in a coordinated fashion but also meets the needs of the 21st century is likely a better scenario than either continuing or terminating the treaty. But the treaty itself does not allow explicitly for modification, and the process to revise a cooperative arrangement is challenging. For the purposes of the Seventh Power Plan, it is impossible to know at this time whether and how storage operations in Canada and thus flows across the border may change after 2024, nor what changes may need to be made to storage operations at US projects, both affecting the generation output and patterns of the system. Nor is it possible to know whether and to what extent there will be a change in the power benefits the US will deliver to Canada in the future. This is a level of uncertainty the Council needs to consider in its resource planning.

[a clean version of the suggested revision to the CRT section for Chapter 2 from JS and TE on 10/6, using Tom Karier's version of the morning of 10/5 as a base]

Columbia River Treaty Review

One of the uncertainties with the Pacific Northwest power supply over the next decade is the fate of the Columbia River Treaty, the agreement with Canada executed in the early 1960s. Under the treaty Canada agreed to build three projects in the portion of the Columbia River in British Columbia that store more than 15 million acre of feet of Columbia River runoff. BC Hydro manages the treaty storage projects primarily for flood control and power generation optimization. The US delivers to Canada a share of the downstream power benefits known as the Canadian Entitlement, calculated by a method set forth in the treaty and an accompanying protocol. In 2015 this amounted to X MWh of energy and Y MW of capacity, often delivered during the highest load hours of the month.

Under the treaty, the annual assured flood control operations ends in 2024, to be replaced with a "called upon" flood control operation which has yet to be specified in any detail. Unless the two nations agree to a new arrangement for flood control, there is a good chance flood control operations at both the U.S. and Canadian storage projects will change significantly after 2024, affecting generation patterns as well.

The treaty's provisions governing coordinated power operations do not change automatically in 2024. Either nation may terminate the treaty beginning in 2024, with at least 10 years' notice. Continuing the treaty without any change in the power provisions retains the certainty of the coordinated power operation and the flexibility under the treaty to enter into annual supplemental agreements to modify flows to meet non-power needs. But continuing the treaty provisions would also mean continuing with power operations and methods for calculating downstream power benefits that were designed in the 1960s and appear increasingly out-of-date with current power system operations and with modern perspectives for assessing the value of the treaty operations.

Any consideration or discussion about changes in the treaty related either to flood control or power or both – rather than termination or continuation without change – raises other issues as well, including whether and how to consider fish and wildlife and other ecosystem considerations in the cooperative management of these treaty storage projects.

The Bonneville Power Administrator and the Corps of Engineers' Northwestern Division Engineer (together the designated U.S. Entity under the treaty) joined with other federal agency, state, and tribal personnel from 2011-13 to review the current treaty and recommend changes. Out of this effort came the "U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," delivered to the State Department in December 2013. The US. Entity regional recommendation recommended neither termination nor the status quo, calling instead for the two nations to negotiate a "modernized" treaty with modifications that respond to the current issues with flood control, coordinated power operations, ecosystem needs, and the calculation and sharing of benefits. The Province of British Columbia led a similar review, and produced what it called its "Columbia River Treaty Review: B.C. Decision" at the same time. Neither the U.S. State Department nor Foreign Affairs Canada have responded officially to the regional recommendations. The NW region is waiting for confirmation from the U.S. State Department that they are ready to begin negotiations which could commence within the year.

The main point for this assessment is that the region is heading into a period of uncertainty after many decades of relative certainty and international cooperation. A modified cooperative arrangement that continues to allow for the Canadian storage projects to be operated in a coordinated fashion but also meets the needs of the 21st century is likely a better scenario than either continuing or terminating the treaty. But the treaty itself does not allow explicitly for modification, and the process to revise a cooperative arrangement is challenging. For the purposes of the Seventh Power Plan, it is impossible to know at this time whether and how storage operations in Canada and thus flows across the border may change after 2024, nor what changes may need to be made to storage operations at US projects, both affecting the generation output and patterns of the system. Nor is it possible to know whether and to what extent there will be a change in the power benefits the US will deliver to Canada in the future. This is a level of uncertainty the Council needs to consider in its resource planning.

CHAPTER 3: RESOURCE STRATEGY

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KEY FINDINGS

The resource strategy for the Seventh Power Plan relies on conservation, demand response, and natural gas-fired generation to meet the region's needs for energy and winter peaking capacity. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region's electricity supply. This resource strategy, with its heavy emphasis on low-cost energy efficiency and demand response, provides a least-cost mix of resources that assures the region an adequate and reliable power supply that is highly adaptable and reduces risks to the power system.

The resource strategy for the Seventh Power Plan consists of eight primary actions: 1) achieve the conservation targets in the Council's plan, 2) meet short-term needs for winter peaking capacity through the use of demand response except where expanded reliance on extra-regional markets can be assured, 3) satisfy existing renewable-energy portfolio standards, 4) increase the near term use of existing natural gas fired generation, 5) increase the utilization of regional resources to serve regional energy and capacity needs, 6) ensure that future carbon policies are cost effective and maintain regional power system adequacy, 7) support the research and development of emerging energy efficiency and clean energy resources and 8) adaptively manage future resource development to match actual future conditions.

A RESOURCE STRATEGY FOR THE REGION

The Council's resource strategy for the Seventh Power Plan provides guidance for Bonneville and the region's utilities on choices of resources that will supply the region's growing electricity needs while reducing the economic risk associated with uncertain future conditions, especially those related to state and federal carbon emission reduction policies and regulations. The resource strategy minimizes the costs and economic risks of the future power system for the region as a whole. The timing of specific resource acquisitions is not the essence of the strategy. The timing of resource needs will vary for every utility. Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In contrast, the region has been a hotbed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. The addition of loads from these new data centers to service territory can dramatically change the utilities resource needs. The important message of the resource strategy is the nature and priority order of resource development.

Summary

The resource strategy is summarized below in eight elements. The first two are high-priority actions that should be pursued immediately and aggressively. The next five are longer-term actions that must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The final element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

Energy Efficiency: The Council's found that development of between 1350 and 1450 average megawatts of energy efficiency by 2021 was cost-effective across a wide range of scenarios and future conditions. The Seventh Power Plan's resource strategy calls upon the region to aggressively develop conservation with a goal of acquiring 1,400 average megawatts by 2021, 3100 average megawatts by 2026 and 4,500 average megawatts by 2035. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon emission reduction policies to address climate-change concerns. In addition, conservation resources not only provide annual energy savings, but contribute significantly to meeting the region's future needs for capacity by reducing both winter and summer peak demands.

Demand Response: The Northwest's power system has historically relied on its large hydroelectric generators to provide peaking capacity. While the hydrosystem can typically meet the region's winter peak demands, that likelihood decreases under critical water and weather conditions, which increases the probability of not meeting the Council's resource adequacy standard without development of additional winter peaking resources.

In order to satisfy regional resource adequacy standards the region should be prepared to develop a significant quantity of demand response resources by 2021 to meet its need for additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources – voluntary and temporary reductions in consumers' use of electricity when the power system is stressed. However, the Council's analysis also found that the need for demand response resources was highly sensitive to assumptions regarding the availability and prices of importing power from outside the region to meet winter peak demands under lower water and extreme temperature conditions. Therefore, the Seventh Power Plan recommends that the annual assessment of regional resource adequacy consider the comparative cost and economic risk of increased reliance on external market purchases versus development of demand response resources within the region.

Natural Gas: It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. At the regional level, the probability that new natural gas-fired generation will be needed to supply winter peaking capacity prior to 2021 is quite low. If the region does not deploy the demand response resources and develop the level of energy efficiency resources called for in this plan, the need for most costly new gas-fired generation increases. In the mid-term (by 2026) there appears to be a modest probability that new gas fired generation could be needed to replace retiring coal generation or potentially to displace additional coal use to meet federal carbon-reduction goals. Nevertheless, even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration when transmission and power market access is limited. In these instances, the Seventh Power Plan's resource strategy relies on new natural gas-fired generation to provide energy, capacity, and ancillary services.

Renewable Resources: The Seventh Power Plan's resource strategy assumes that only modest development of renewable generation, approximately 300 average megawatts of energy, or around 900 megawatts of installed capacity, is necessary to fulfill existing renewable portfolio standards. While the majority of historical renewable development in the region has been wind resources, recent and forecast further cost reductions in solar photovoltaic (solar PV) technology are expected to make electricity generated from such systems increasingly cost-competitive. In addition, solar PV systems, particularly when coupled with storage, can provide summer peaking services for which regional demand is increasing faster than winter peaking needs. As a result, solar PV systems should be seriously considered when determining which resources to acquire to comply with existing renewable portfolio standards.

The Seventh Power Plan's resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. Because power production from wind and solar PV projects creates little dependable winter peak capacity and increases the need for within-hour balancing reserves the strategy also encourages research on and demonstration of different sources of renewable energy for the future, especially those with a more consistent output like geothermal or wave energy.

Increasing the requirements of state renewable portfolio standards would not result in the development of the least cost resource strategy for the region. Moreover, increased renewable portfolio standards are not necessary to comply *at the regional level* with recently promulgated federal carbon dioxide emissions regulations.

Regional Resource Utilization: The region should continue to improve system scheduling and operating procedures across the region's balancing authorities to maximize cost-effectiveness and minimize the need for new resources needed for integration of variable energy resource production. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation. Finally, the Council identified least cost resource strategies for the region that rely first on regional resources to satisfy the region's resource adequacy standards. Under many future conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy efficiency resources called for in this plan and replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, especially technologies that can provide both energy and winter capacity, improved regional transmission capability, new conservation technologies, new energy-storage techniques, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities. For example, the potential for developing geothermal and wave energy in the Northwest is significantly greater than in many other areas of the country.

Adaptive Management: The Council will annually assess the adequacy of the regional power system. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions that it would require adjustments to the plan. This annual assessment will provide the region time to take actions necessary to reduce the probability of power shortages. The Council will also conduct a mid-term assessment to review plan implementation.

SCENARIO ANALYSIS – THE BASIS OF THE RESOURCE STRATEGY

The Seventh Power Plan's resource strategy is based on analysis of over 20 scenarios and sensitivity studies. Scenarios combined elements of the future that the region controls, such as the type, amount and timing of resource development, with factors the region does not control, such as natural gas and wholesale market electricity prices. Sensitivity studies alter one parameter in a scenario to test the how the least-cost resource strategy is affected by that input assumption. For example, several scenarios where run with and without future carbon cost to assess the impact of that input assumption on the various components of the least cost resource strategy.

All of the scenarios evaluated for the plan include the same range of uncertainty regarding future fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. However, several scenarios were specifically designed to provide insights into the cost and impacts of alternative carbon dioxide emissions reduction policies. These included either the federal government's estimates of the societal damage cost of carbon dioxide emissions or the economic risk associated with future carbon dioxide regulation or pricing or "non-pricing" policies. Each of these scenarios assumed differing levels of carbon dioxide damage or regulatory cost. Also, as noted above, several sensitivity studies were conducted to assess the impact of such factors as the near term pace of conservation development, lower natural gas and wholesale electricity prices, greater reliance on external markets or the loss of major resources.

Each scenario and sensitivity analysis tested thousands of potential resource strategies against 800 alternative future conditions to identify the least cost and lowest economic risk resource portfolios. Since the discussion of the elements of the resource strategy draws on those scenarios and sensitivity studies, an introduction to the scenarios and studies and their findings is needed. Each scenario or sensitivity study was designed to explore specific components of resource strategies (e.g. strategies with and without demand response). Therefore, the following discussion of findings compares different combinations of scenarios and sensitivity studies. That is, not all scenarios or sensitivity studies "stress test" the same element of a resource strategy, so not all provide useful insight regarding that element.

The US Environmental Protection Agency (EPA) released its draft Clean Power Plan in June, 2014, and its final set of regulations in August, 2015. These regulations establish carbon dioxide emissions limits for both new and existing power plants. Five of the scenarios summarized below: the two Social Cost of Carbon (Mid-Range and High), Carbon Cost Risk, Renewable Portfolio Standards at 35 Percent and Maximum Carbon Reduction – Existing Technology, were designed to test alternative policies that may be considered at the regional or state level to identify resource strategies that would comply with those regulations. Two other scenarios, the Planned Loss of a Major Non-Greenhouse Gas (GHG) Emitting Resource and the Unplanned Loss of a Major Non-GHG Emitting Resource were analyzed to provide insights into the effect of the loss of a major non-greenhouse gas-emitting would have on the region's ability reduce power system carbon dioxide emissions.

The bullets below summarize the 15 principal scenarios or sensitivity studies that informed the development of the Seventh Power Plan's resource strategy.

- **Existing Policy –** The existing-policy scenario includes current policies such as renewable portfolio standards, new plant emissions standards, and renewable energy credits, but it does not assume any carbon dioxide regulatory cost risk in the future. It helps identify the effect of carbon dioxide cost risk when added to existing policies. Other major uncertainties regarding the future, such as load growth and natural gas and market electricity prices are considered.

- **Social Cost of Carbon (SCC) –** Two scenarios, the **Social Cost of Carbon – Mid-Range (SCC-Mid-Range)** and **Social Cost of Carbon – High (SCC-High)**, use the US Interagency Working Group on Social Cost of Carbon's estimates of the damage cost of forecast global climate change. According to the Working Group:

    - o *The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction).*

    - o Therefore, in theory, the cost and economic risk of the resource strategy that achieves carbon dioxide emissions reductions equivalent to the Social Cost of Carbon would offset the cost of damage. The "SCC-Mid-Range" scenario uses the Interagency Working Group's mid-range estimate of the damage cost from carbon dioxide emissions based on a three percent discount rate. The SCC-High scenario uses the Interagency Working Group's estimate of damage cost that encompasses 95 percent of the estimated range of damage costs.[1]

- **Carbon Cost Risk –** The carbon cost risk scenario is intended to explore what resources result in the lowest expected cost and economic risk given existing policy plus the economic risk that additional carbon dioxide reduction policies will be implemented. Each of the 800 futures imposes a carbon dioxide price from $0 to $110 per metric ton at a random year during the 20 year planning period. Over time, the probability of a carbon dioxide price being imposed and the level of that price both increase. By 2035, the average price of carbon dioxide rises to $47 per metric ton across all futures. It should be noted, that the use of a

[1] Chapter 15 provides the year-by-year social cost of carbon used in these scenarios.

carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax) would be used to reduce carbon dioxide emissions. The prices imposed in this scenario could also be a proxy for the cost imposed on the power system through regulation to reduce carbon dioxide emissions (e.g., caps on emissions).

- This scenario was initially designed to represent the current state of uncertainty about future carbon dioxide control policies and develop a responsive resource strategy. It is identical to a scenario analyzed for the development of the Sixth Power Plan. While with the promulgation of Environmental Protection Agency's carbon dioxide emissions regulations there is less uncertainty regarding federal regulations, the specific form of state and/or regional compliance plans with EPA's regulations are unknown. Moreover, some states may choose to adopt additional policies beyond the federal regulations to limit power system emissions.

- **Renewable Portfolio Standard at 35 Percent (RPS at 35 percent) –** This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional electricity load across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of load be served by renewable resources. Montana's RPS must be satisfied by in 2015 and Washington's by 2020. Oregon requires that 20 percent of load be served by renewable resources by 2020. Since this scenario was designed to test the cost and effectiveness of this policy for reducing regional power system carbon dioxide emissions, it did not include future carbon dioxide regulatory cost risk uncertainty or estimated damage cost. The cost-effectiveness of a policy that only requires use of additional renewable generation can, therefore, be compared to other scenarios that tested alternative policy options to reduce carbon dioxide emissions.

- **Maximum Carbon Reduction – Existing Technology –** This scenario was designed to explore the maximum carbon dioxide emissions reductions that are feasible with current commercially available technologies. In this scenario all of the existing coal plants serving the region were assumed to be retired by 2026. In addition, the least efficient (i.e., those with heat rates exceeding 8,500 Btu/kWh) existing natural gas-fired generating facilities were assumed to be retired by 2031. No carbon dioxide cost risk or estimated damage cost was assumed, so this scenario can be compared to the cost-effectiveness of other policy options (e.g., Carbon Cost Risk, RPS at 35 percent, the two Social Cost of Carbon scenarios) for reducing carbon dioxide emissions.

- **Maximum Carbon Reduction – Emerging Technology –** This scenario considers the role of new technologies might play in achieving carbon dioxide reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario the Council's Regional Portfolio Model (RPM) was not used to identify this scenario's least cost resource strategy. Rather, the RPM was used to define the role (e.g., capacity and energy requirements) that new and emerging technologies would need to play in order to achieve carbon dioxide reductions beyond those achievable with existing technology.

- **Resource Uncertainty –** Four scenarios explored resource uncertainties and carbon dioxide regulatory compliance cost and economic risk. Two examined the effect that the loss of a major non-greenhouse gas-emitting resource might have on the region's ability to reduce power system carbon dioxide emissions. The **Unplanned Major Resource Loss** scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpectedly taken out of service. The **Planned Major Resource Loss** scenario assumed that similar magnitudes of the region's existing non-greenhouse gas emitting resources were phased out over the next 20 years. Since both of these scenarios were designed to identify resource strategies that would maintain regional compliance with federal carbon dioxide emissions limits they assumed the cost of future carbon dioxide regulatory risk used in the Carbon Cost Risk scenario.

- Two additional scenarios tested the economic benefits or cost resulting from a faster or slower near term pace of conservation deployment. The **Faster Conservation Deployment** scenario allowed the Regional Portfolio Model to increase the pace of acquiring conservation savings by 30 percent above the baseline assumption. The **Slower Conservation Deployment** scenario restricted the RPM's option to acquire conservation savings to a pace that was 30 percent below the baseline assumption. Since both of these scenarios were designed to test resource strategies that might reduce the cost or increase the economic risk of compliance with federal carbon dioxide emissions limits, they assumed the carbon dioxide regulatory cost risk used in the Carbon Cost Risk scenario.

- **No Demand Response –** This sensitivity study assumed that no demand response resources were available to meet future regional peak capacity needs. It estimated the cost and risk of not using demand response to provide regional capacity reserves under both the Existing Policy scenario and with the future carbon dioxide regulatory cost assumed in the Carbon Cost Risk scenario.

- **Low Natural Gas and Wholesale Electricity Prices –** This sensitivity study assumed that the range of future natural gas and wholesale electricity prices the region would experience was systematically lower than the baseline assumptions. It was designed to test the impact of lower gas and electricity prices on the amount of cost-effective conservation and on the best future mix of generating resource development. This sensitivity study was tested under both the Existing Policy scenario and with the future carbon dioxide regulatory cost assumed in the Carbon Cost Risk scenario.

- **Increased Market Reliance –** This scenario explored the potential benefits and risk of increased reliance on out-of-region markets to meet regional resource adequacy standards. It evaluated the cost of meeting near-term peak capacity needs with demand response and other regional resources compared to reliance on Southwest markets. This sensitivity study was conducted using the Existing Policy scenario.

- **Lower Conservation –** This sensitivity study explored the potential costs and benefits associated with less reliance on energy efficiency. Under this scenario, the acquisition of conservation was limited to what would be cost-effective to acquire based on short-run market prices, rather than full consideration of long-term resource costs and risks. This sensitivity study was conducted using the Existing Policy scenario, so no carbon dioxide regulatory cost risk or damage costs were assumed.

Results of these studies are compared in the discussion of the eight elements of the resource strategy in the following section. A discussion of the specific input assumptions for each of these scenarios as well as a more comprehensive discussion of carbon dioxide emissions, rate and bill impacts and the Regional Portfolio Model appears in Chapter 15 and Appendix L.

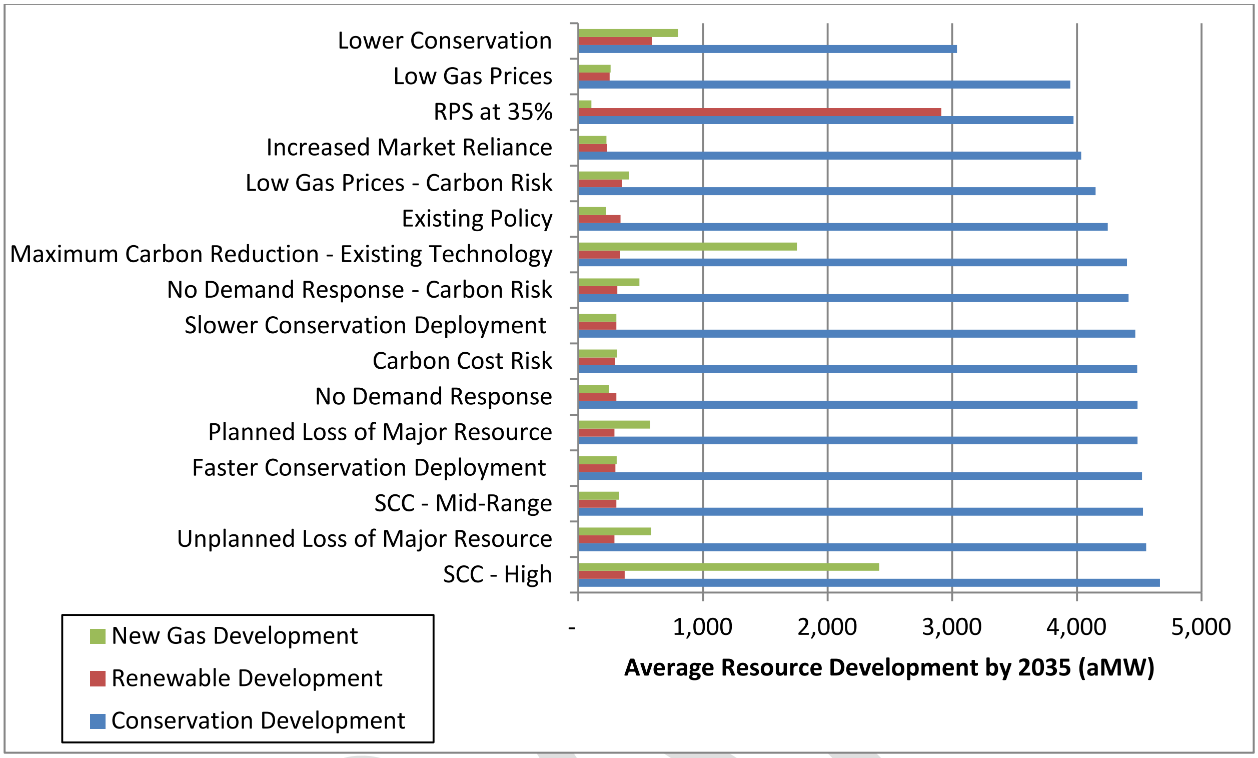
THE RESOURCE STRATEGY

The resource strategy of the Seventh Power Plan is designed to provide the region a low-cost electricity supply to meet future load growth. It is also designed to provide a low economic risk electricity future by ensuring that the region develops and controls sufficient resources to maintain resource adequacy, limiting exposure to potential market price extremes. Therefore the amount and type of resources included in the strategy are designed to meet loads, minimize costs, and help reduce the economic risks posed by uncertain future events.

Figure 3 - 1 shows the average resource development by resource type for the least cost resource strategy under the major scenarios and sensitivity studies carried out to support the development of the Seventh Power Plan. The resource development shown in Figure 3 - 1 is the *average* over all 800 futures modeled in the Regional Portfolio Model (RPM). In the RPM the specific timing and level of resource development is unique to each of the 800 potential futures modeled. The Seventh Power Plan's principal of adaptive management is based on the reality that, as in the RPM, the timing and level of resource development in the region will be determined by actual conditions as they unfold over the next 20 years. However, what should not change are the Seventh Power Plan's priorities for resource development. In that regard, Figure 3 - 1 shows the significant and consistent role of energy efficiency across all scenarios. This is because of its low cost, its contribution to regional winter capacity needs and its role in mitigating economic risk from fuel price uncertainty and volatility.

After energy efficiency, the *average* development of new natural gas generation and renewable resources by 2035 is roughly equivalent. New natural gas-fired resources are developed to meet regional capacity needs while renewable resource development is driven by state renewable resource portfolio standards. Not shown in Figure 3 - 1 is the deployment of demand response resources because these resources primarily provide capacity (megawatts) not energy (average megawatts) and the increased dispatch of existing gas generation to replace retiring coal generation. Both of these resources also play significant roles in the Seventh Power Plan's resource strategy. Each element of the resource strategy is discussed below.

Figure 3 - 1: Average Resource Development in Least Cost Resource Strategy by 2035 in Alternative Scenarios



Energy Efficiency Resources

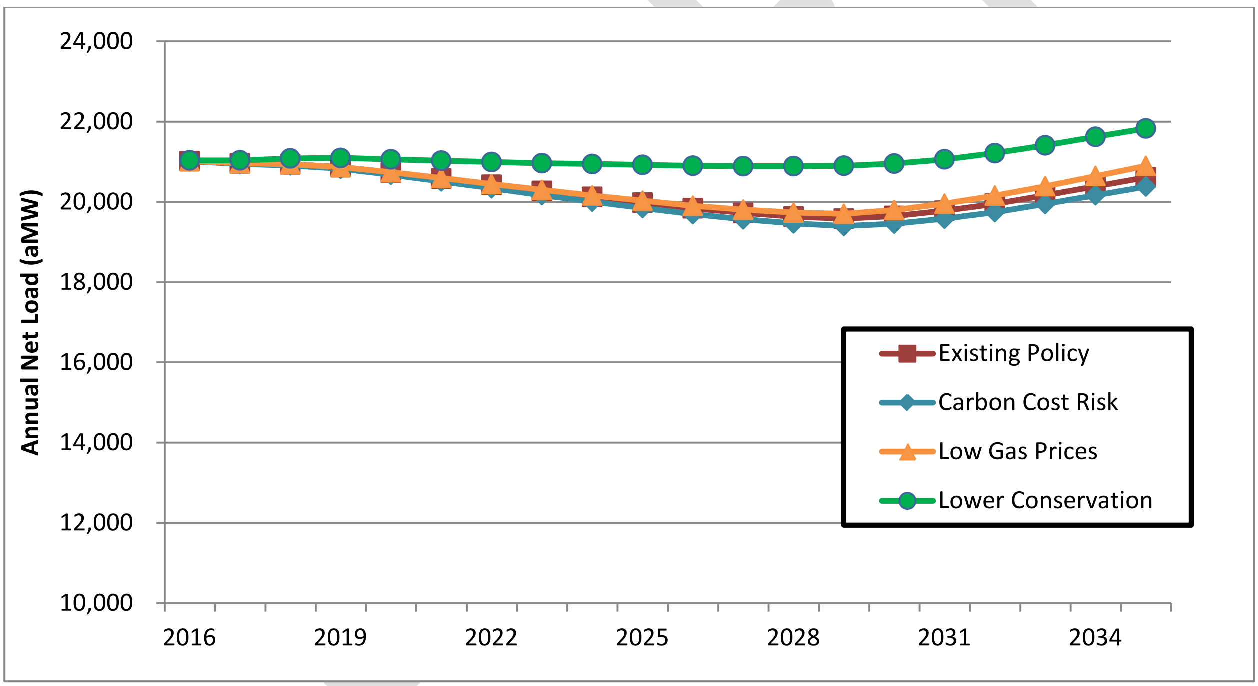
Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,900 average megawatts of conservation. This achievement makes efficiency the second-largest source of electricity in the region following hydroelectricity.

As in all prior plans, the highest priority new resource in the Seventh Power Plan resource strategy is improved efficiency of electricity use, or conservation. Figure 3 - 2 shows that the region's net load after development of all-cost effective energy efficiency remains essentially the same over the next 20 years. This finding holds under scenarios that both consider carbon dioxide risk or damage cost and those that do not and even when natural gas and electricity prices are lower than generally anticipated. The only scenario that developed significantly less energy efficiency was the scenario specifically designed to do so. The **Lower Conservation** scenario developed roughly 1200 average megawatts less energy efficiency by 2035 than the **Existing Policy** scenario. The **Lower Conservation** scenario had significantly higher ($14 billion) average system cost and exposed the region to much larger ($19 billion) economic risk than the **Existing Policy** scenario. However, as Figure 3 - 2 shows, even under that scenario, the development of energy efficiency offsets regional load growth through 2030.

The attractiveness of improved efficiency is due to its relatively low cost coupled with the fact that it provides both energy and capacity savings and is not subject to major sources of economic risk. The average cost of conservation developed in the least cost resource strategies across all scenarios tested was half the cost of alternative generating resources. The average levelized cost of the cost-effective efficiency developed in the Seventh Power Plan's resource strategy is $30 per megawatt-hour.[2] The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility scale solar photovoltaic systems is approximately $65 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour, including the cost of integrating these variable output resources into the power system. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,300 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

Conservation also lacks the economic risk associated with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk. Therefore, improved efficiency reduces both the cost and economic risk of the Seventh Power Plan's resource strategy.

Figure 3 - 2: Average Net Regional Load After Accounting for Cost-Effective Conservation Resource Development



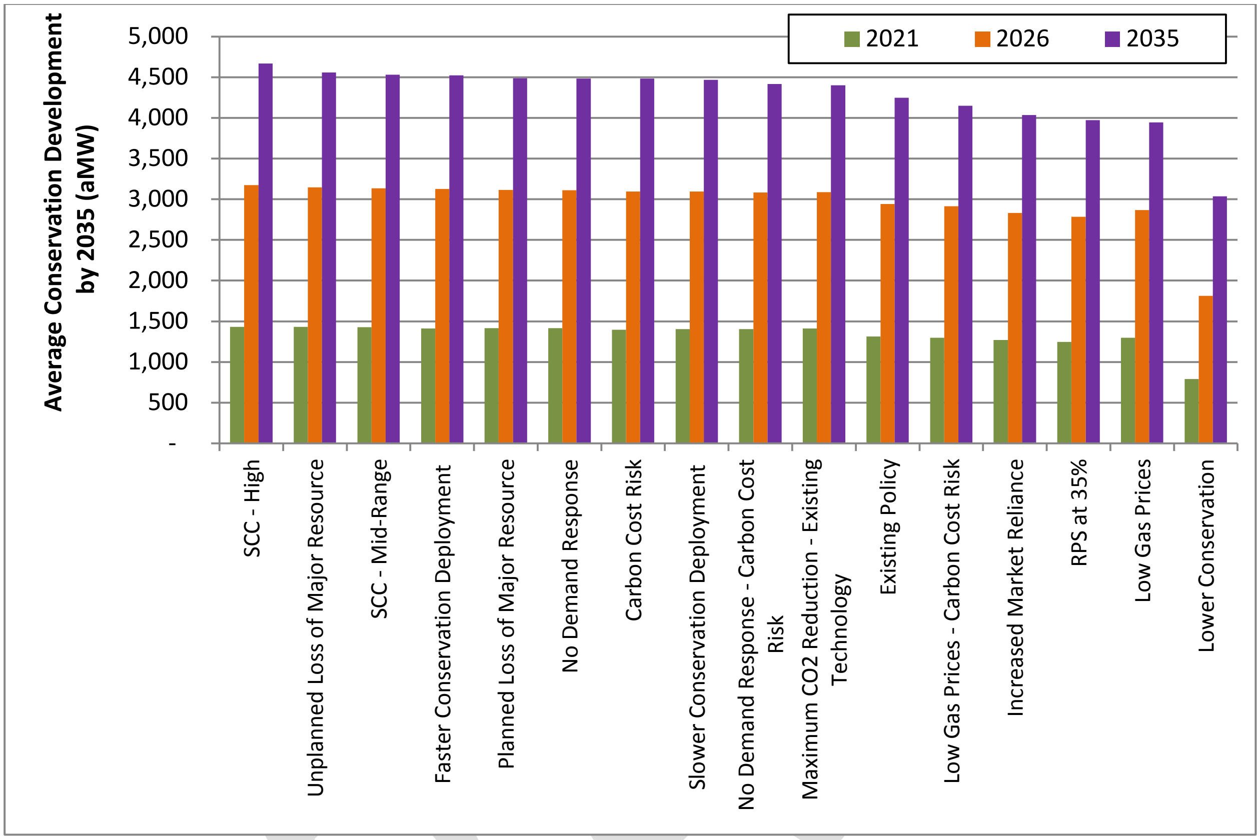
[2] This is the average real levelized cost of all conservation measures acquired in the resource strategy, excluding a cost-offset that is expected to occur as a result of lower load growth which defers the need to expand distribution and transmission systems. In evaluating conservation's cost-effectiveness in the RPM, this cost-offset was included, as well as other non-energy benefits, such as water savings from more efficient clothes washers. If the cost-offset benefits provided by energy efficiency's deferral of investments in distribution and transmission expansion are considered, the average levelized cost is $18 per megawatt-hour.

In the Council's analysis, additional resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not immediately needed, the energy and capacity can be sold in the market and all or at least a portion of their cost recovered. This is not true for generating resources, for in periods when market prices are at or below their variable operating cost; these resources cannot recover any of their capital cost. In addition, because of its low average cost to utilities, the development of energy efficiency offers the potential opportunity to extend the benefits of the Northwest's hydro-system through increased sales.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency were found to be cost-effective.[3] The selection of energy efficiency as the primary new resource does not depend significantly on whether or not carbon dioxide policies are enacted. Figure 3 - 3 shows the amount of efficiency acquired in various scenarios considered by the Council in the power plan by 2021, 2026 and 2035. In all scenarios, the amount of cost-effective efficiency developed averages between 1,300 and 1,450 average megawatts by 2021 and 3,900 and 4,600 by 2035. The amount of conservation developed varies in each future considered in the regional portfolio model. For example, in the Carbon Cost Risk scenario, the average conservation development is 4,485 average megawatts, but individual futures can vary from as low as 4,000 average megawatts to as high as just over 5,000 average megawatts.

[3] The only exception is the Lower Conservation scenario which as explicitly designed to develop less energy efficiency.

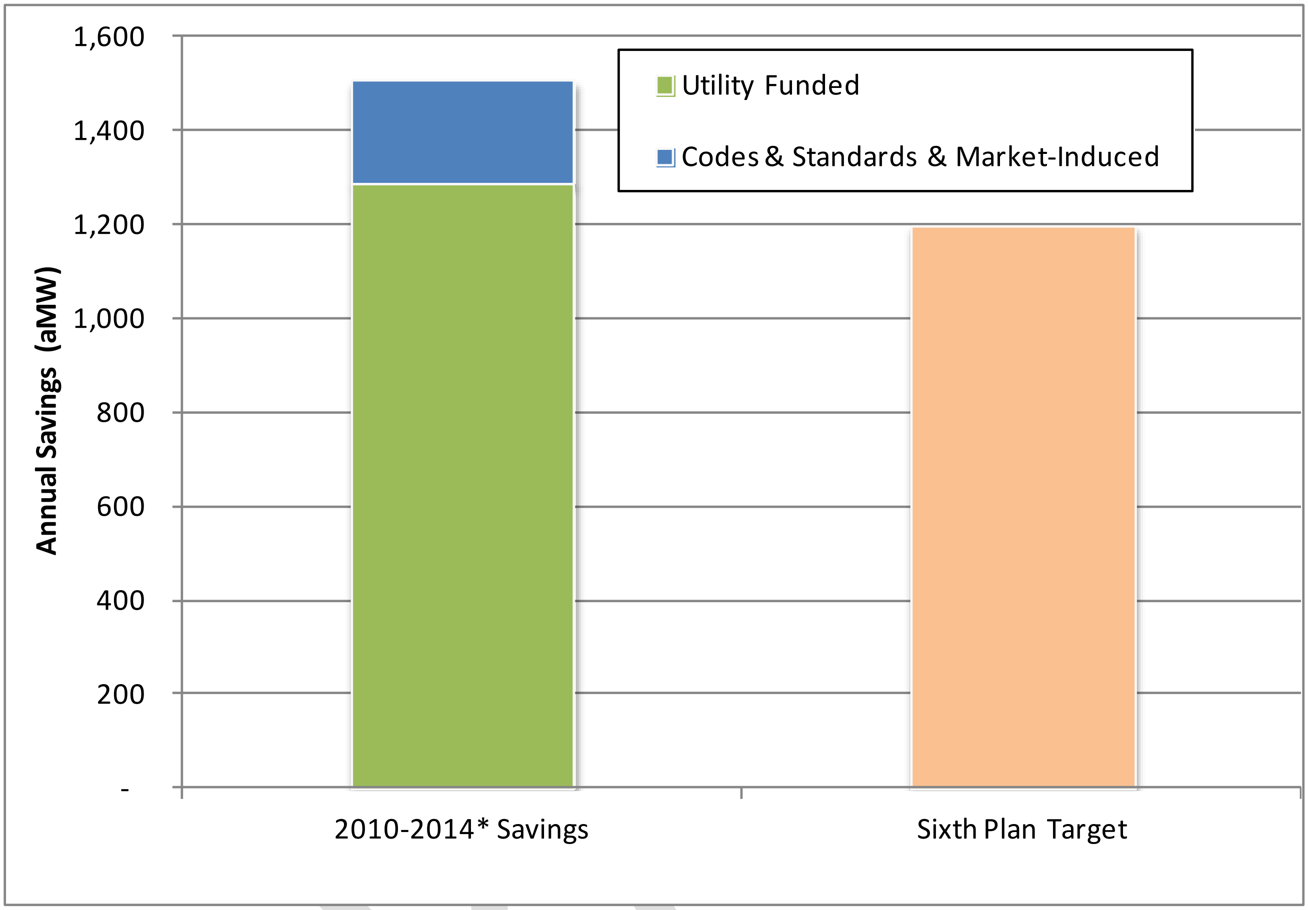
Figure 3 - 3: Amount of Cost-Effective Conservation Resources Developed Under Different Scenarios



The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of other new generating resources will increase everyone's bills. The impact on both bills and average revenue requirement per kilowatt-hour is discussed later in this chapter.

The amount of efficiency included in the Seventh Power Plan is comparable to that identified in the Council's Sixth plan; even though the 20-year goal is lower (4,500 aMW vs. 5800 aMW). To a large extent, this decrease is the result of regional conservation program achievements since the Sixth Plan was adopted in 2010 as well as significant savings that will be realized as a result of federal standards and state codes enacted since the Sixth Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 (projected) compared to the Sixth Plan's conservation goal for the same period. In addition, Figure 3 - 4 shows the savings achieved from the combined impact of federal and state appliance and equipment standards, state building codes and market-induced savings. In aggregate, actual achievements from 2010 through 2014 were nearly 1500 average megawatts, exceeding the Sixth Plan's five year goal of 1200 average megawatts by 25 percent.

Figure 3 - 4: Regional Conservation Achievements Compared To Sixth Plan Goals



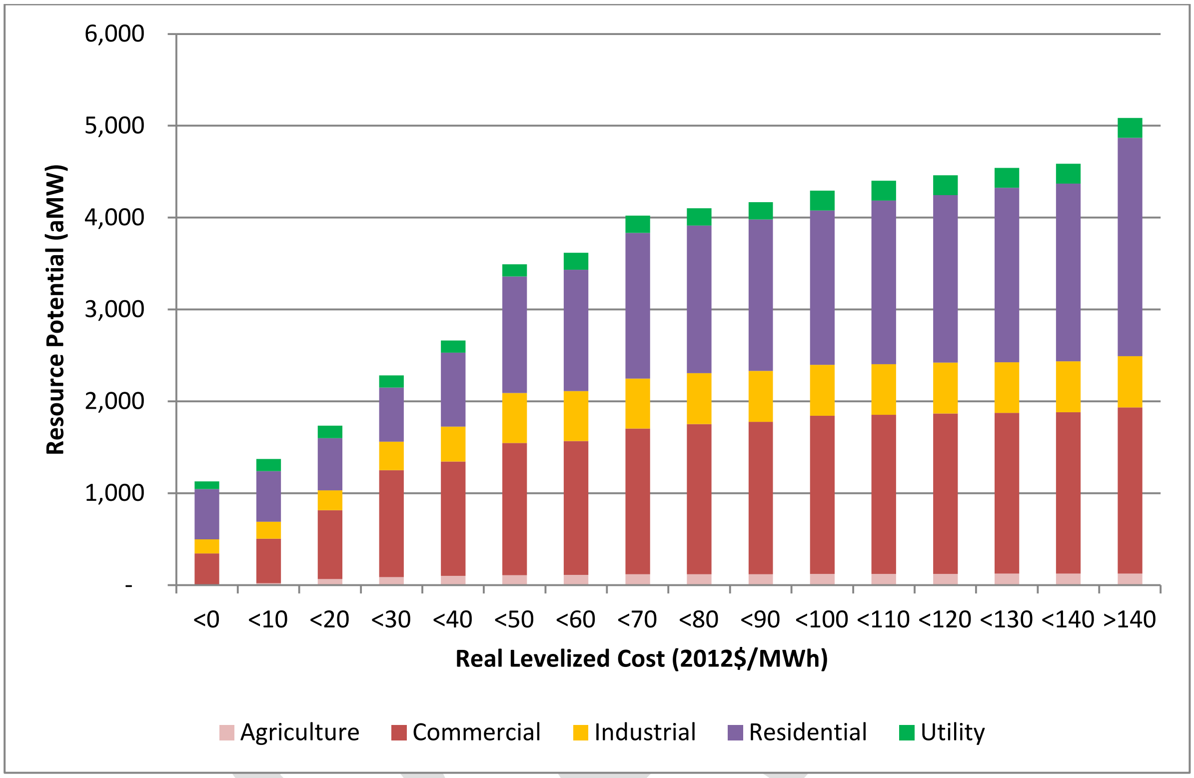
* 2014 savings are preliminary

Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified in the Sixth Plan. The Council estimates that collectively these standards will reduce forecast load growth by nearly 1500 average megawatts by 2035.

The Council has identified significant new efficiency opportunities in all consuming sectors. Figure 3 - 5 shows by levelized cost the sectors of efficiency improvements. Additional information on the sources and costs of efficiency improvements is provided in Chapter 12 and Appendix G.

Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes more to load reduction during times of peak usage. To model the impact of energy efficiency on the hourly demand for electricity, the Council aggregated the load shapes of efficiency savings from the hourly shape of individual end-uses of electricity and the cost-effective efficiency improvements in those uses. Figure 3 - 6 shows the shape of the savings for all measures during heavy and light load hours. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of lighting during the winter period.

Figure 3 - 5: Efficiency Potential by Sector and Levelized Cost by 2035



For example, efficiency improvements that yield average annual savings of 4,485 average megawatts create 10,700 megawatts of peak hour savings during the winter months.[4] The capacity impact of energy efficiency is almost two times the energy contribution in winter. This reduction in both system energy and capacity needs makes energy efficiency a valuable resource relative to generation because efficiency provides winter energy and capacity resources shaped to load. Because each efficiency measure has a specific shape, or capacity impact, the Seventh Power Plan explicitly incorporates the value of deferred generation capacity in the cost-effectiveness methodology for measures and programs.[5]

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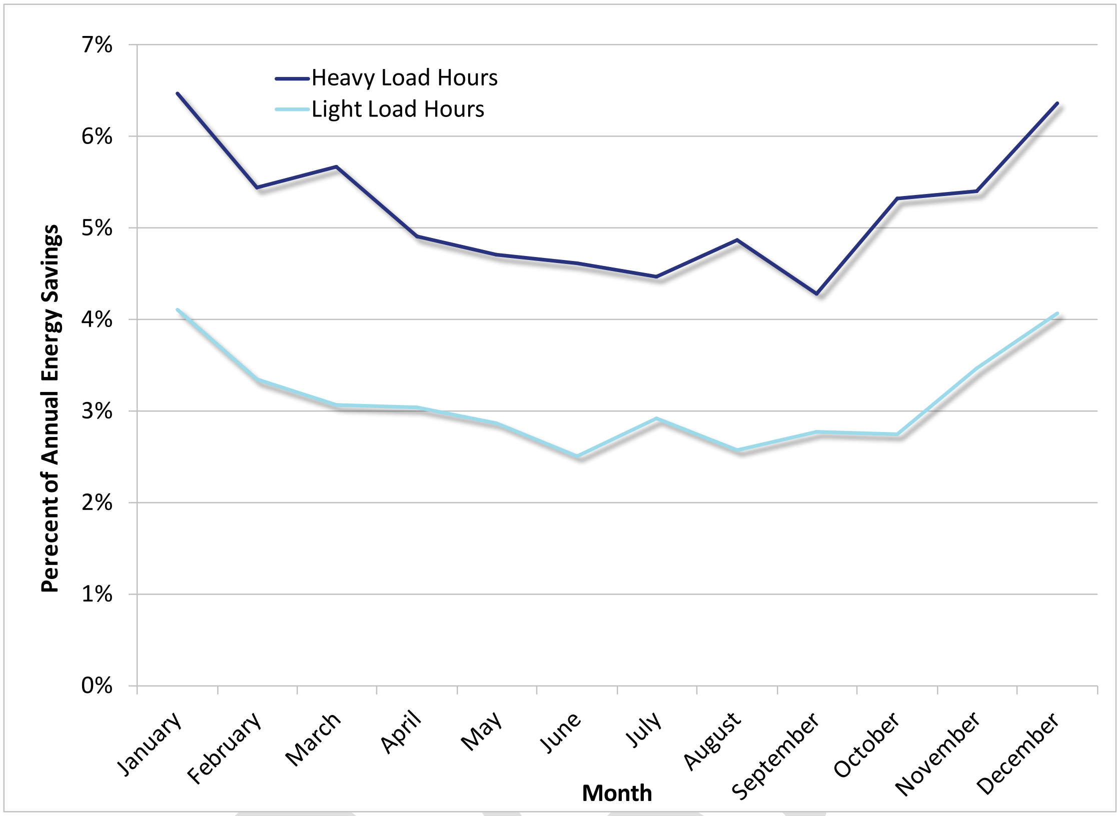
[4] See Chapter 12 for a description of how the capacity savings of energy efficiency measures are estimated and Chapter 11 for a description of how the system level capacity savings, or Associated System Capacity Contributions, of conservation and generation resources are estimated.
[5] See action items RES-2 and RES-3 in Chapter 4 and Appendix G

Figure 3 - 6: Monthly Shape of 2035 Efficiency Savings



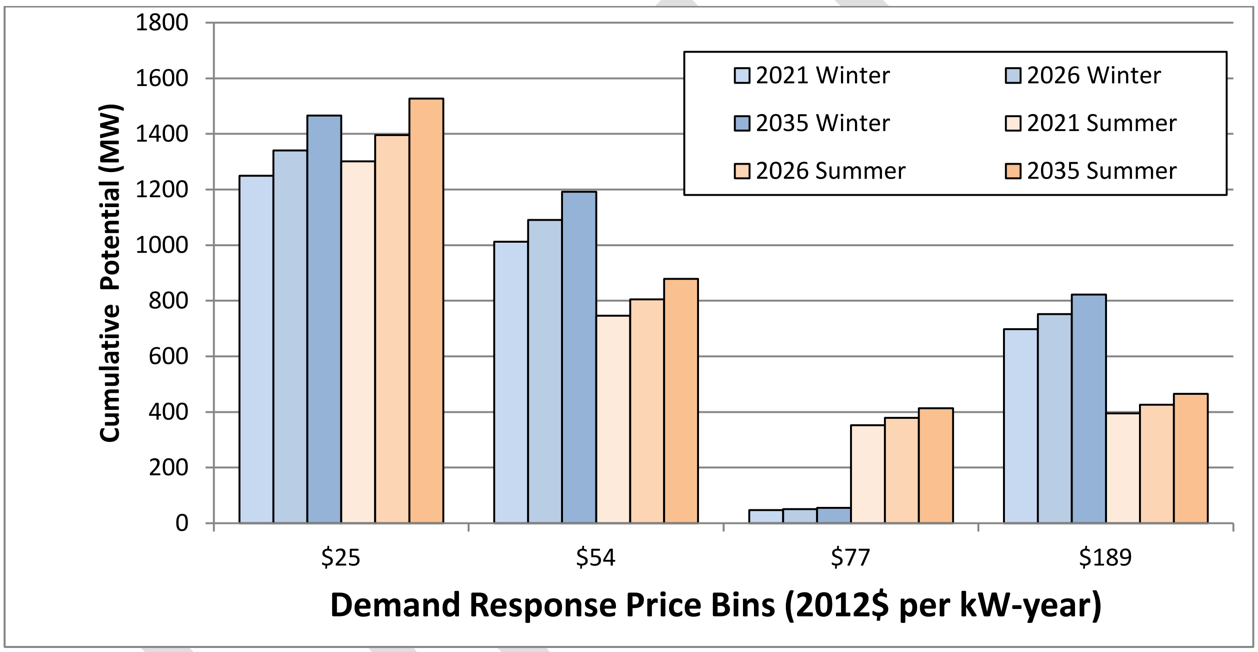
Demand Response

Demand response resources (DR) are voluntary reductions (curtailments) in customer electricity use during periods of high demand and limited resource availability. As deployed in the Seventh Power Plan, demand response resources are used to meet winter and summer single-hour peak demands primarily under critical water and extreme weather conditions. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not considered in the Seventh Power Plan.

In many areas of the US demand response resources have long been used by utilities to offset the need to build additional peaking capacity. In the Northwest, the existing hydropower system has been able to supply adequate peaking capacity, so the region has far less experience with deployment of demand response resources. To assess the economic value of developing demand response in the Northwest the Council conducted two sensitivity studies that assumed demand response resources were not available. The average net present value *system cost* and *risk* of the least cost resource strategy without demand response were $1 billion higher than in the least cost resource strategy that was able to deploy this resource. Therefore, from the Seventh Power Plan's analysis it appears that if barriers to development can be overcome and the Council's analysis of the cost of demand response are accurate; demand response resources could provide significant regional economic benefits.[6]

The Council's assessment identified more than 4300 megawatts of regional demand response potential. A significant amount of this potential, more than 1500 megawatts, is available at relatively low cost, under $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response resources can be deployed sooner and in quantities better matched to the peak capacity need. Figure 3 - 7 shows the cumulative potential for each of the four blocks (i.e., price bins) of demand response modeled in the Regional Portfolio Model. Cumulative achievable potential by the years 2021, 2026 and 2035 is shown for both winter and summer capacity demand response programs. Note that the largest single block of estimated demand response potential is also the least costly.

Figure 3 - 7: Demand Response Resource Supply Curve



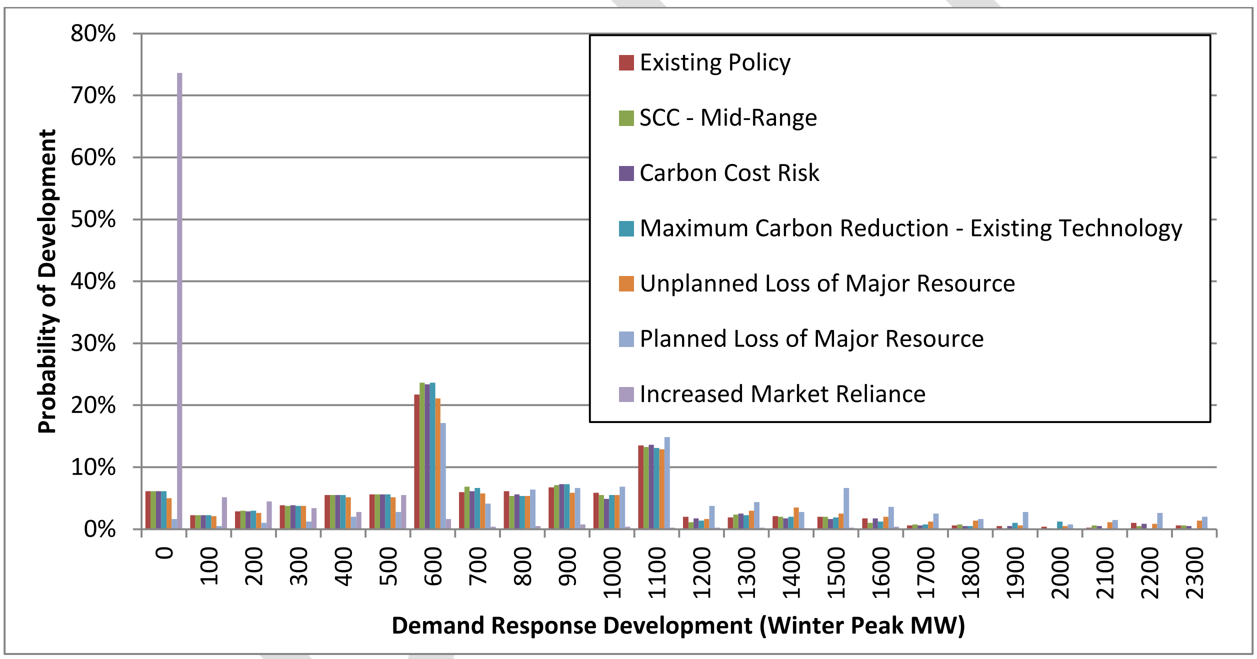
The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources make them particularly valuable because the need for peaking capacity resources to meet resource adequacy in the region is a function of a combination of water and weather conditions that have low probability of occurrence. This is illustrated by Figure 3 - 8 which shows the amount of demand response resource needed by 2021 across the 800 futures tested in the RPM across multiple scenarios.

[6] See Chapter 4 for the Action Items the Seventh Power Plan recommends the region and Bonneville should engage to specifically address the barriers to development of demand response resources.

Figure 3 - 8 shows that there is a wide range of both the amount and probability of development from zero up to 2300 MW, depending on what scenario is being analyzed. In the **Increased Market Reliance** scenario**,** more than 70 percent of the futures require no demand response development. Under most other scenarios there is around a 20 percent probability that as much as 600 MW of demand response will need to be developed by 2021 and a 15 percent probability that as much as 1100 MW would need to be developed.

It is striking to note the contrast in demand response development in the **Increased Market Reliance** scenario**,** which assumed the region could place greater reliance on external power markets to meet its winter peak capacity needs, and other scenarios that used the limits on external market reliance used in the Regional Resource Adequacy Assessment. The amount of demand response developed *on average* across all futures decreased from 700 MW to less than 100 MW. In this scenario, net present value system cost and economic risk were also lower. This highlights the sensitivity of the assumed limits on external market reliance used in the Council Regional Resource Adequacy Assessment and the potential value to the region if it can rely upon additional imports.

Figure 3 - 8: Demand Response Resource Development by 2021 Under Alternative Scenarios



Renewable Generation

Since the adoption of the Sixth Plan renewable generating resources development has increased significantly. This development was prompted by Renewable Portfolio Standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region – about equivalent to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

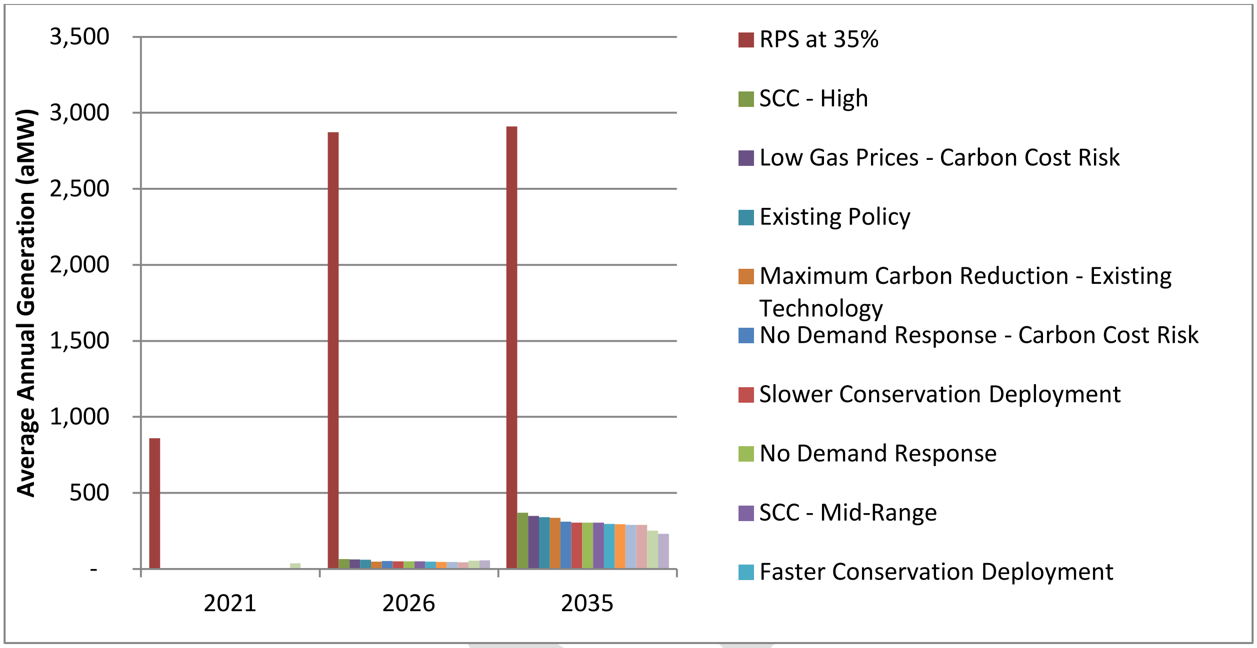
It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

Existing wind resources are estimated to provide about 2,400 average megawatts of energy generation per year in the region, or about 8 percent of the region's electricity energy supply. However, on a firm capacity basis, wind resources only provide about 1 percent of the region's total system peaking capability. The Council's current analysis of wind's ability to supply peaking capacity is based on the Resource Adequacy Assessment Advisory Committee's estimate that wind can only be relied upon to provide about 5 percent of its nameplate capacity toward meeting peak loads due to the variable nature of the resource.

Aside from hydropower, the renewable resources included in the Regional Portfolio Model (RPM) are wind and solar photovoltaic (solar PV). The Council recognizes that additional small-scale renewable resources are likely available and cost-effective. These small-scale renewables were not modeled in the RPM but the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources not captured in the resource strategy that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

New wind resources that have ready access to transmission produce energy at costs that are competitive on an energy basis with other generation alternatives. Recent and forecast reductions in solar PV system cost are making utility scale system's energy production cost increasingly cost-competitive. However, renewable generation development in the scenarios tested for the Seventh Power Plan is driven by state RPS and not economics. Figure 3 - 9 shows the average development of renewable resources across scenarios analyzed for the Seventh Power Plan. As can be seen from this figure, under all least cost resource strategies for all scenarios, except when the RPS were assume to increase to 35 percent, only 300 to 400 average megawatts of renewable resource development occurs later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances are forecast to be drawn down.

Figure 3 - 9: Average Renewable Resource Development by Scenarios by 2021, 2026 and 2035



The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 800 futures of demand growth in the **Carbon Cost Risk** scenario, the amount of wind and solar PV developed on average is about 300 average megawatts, with slightly more solar PV developed than wind. The only exception to this level of development is the **RPS at 35 percent** scenario that assumed regional renewable resource portfolio standards would be increased to 35 percent of annual regional load. In this scenario the least cost resource strategy develops 2,900 average megawatts of additional renewable resources, primarily wind generation by 2035.

The explanation of the outcome described above is that while the two economically competitive renewable resources available in the region, wind and solar PV, produce significant amounts of energy, they provide little or no winter peaking capacity. Partly as a result of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water and extreme weather conditions the region faces the probability of a winter peak capacity shortfall. In short, the generation characteristics of the currently economically competitive renewable resources do not align well with regional power system needs.

As stated above, the development of renewable generation is driven by state renewable portfolio standards more so than regional energy need. In the absence of higher renewable portfolio standards little additional renewable development would take place, even under scenarios where the highest social cost of carbon dioxide (**SCC-High**) might be imposed on the power system.

Natural Gas-Fired Generation

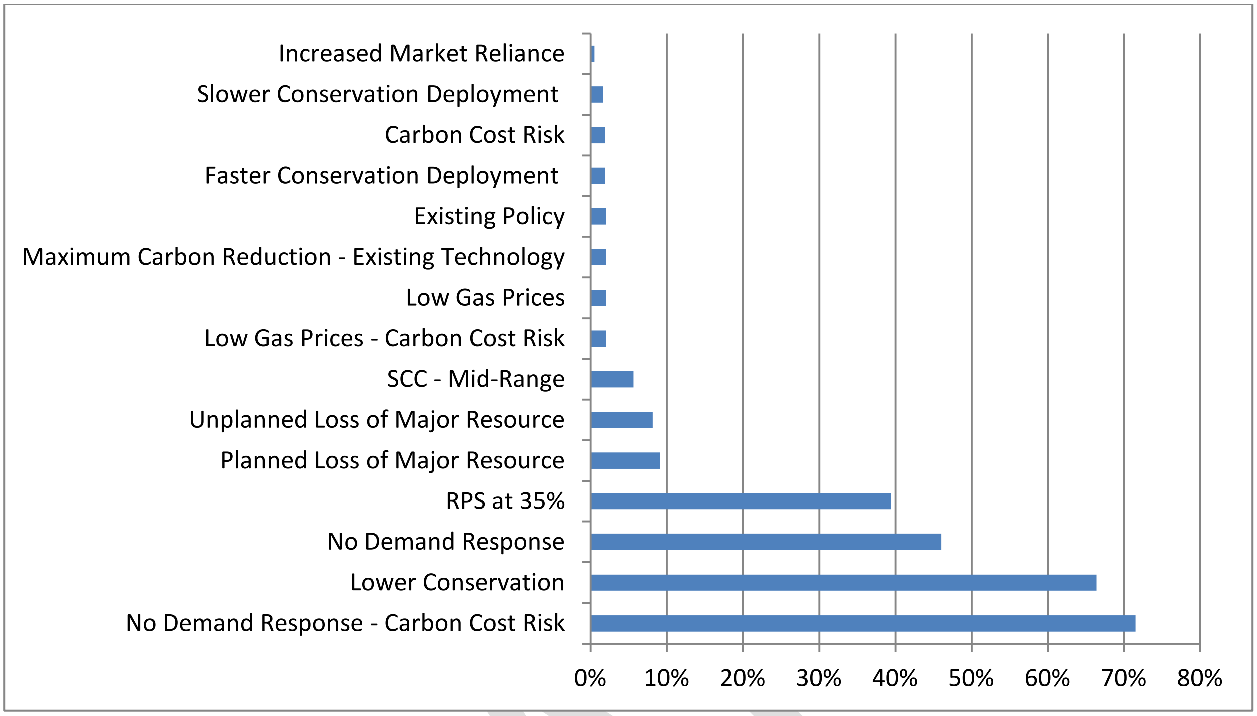
Natural gas is the fourth major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Power Plan identified the increased use of existing natural gas generation as offering the lowest cost option for reducing regional carbon dioxide emissions. Other resource alternatives may become available over time, and the Seventh Power Plan recommends actions to encourage expansion of the diversity of resources available, especially those that do not produce greenhouse gas emissions.

Across the scenarios evaluated, there is significant variance in the amount of new gas-fired generating resources that are optioned and in the likelihood of completing the plants. New gas-fired plants are optioned (sited and licensed) in the RPM so that they are available to develop if needed in each future. The Seventh Power Plan's resource strategy includes optioning new gas fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is limited in the near term (through 2021) and only modest in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are taken to construction in only a relatively small number of futures. Figures 3 - 10 and 3 - 11 show the probability that a thermal resource option would move to construction by 2021 and by 2026. The scenarios are rank-ordered based on the probability of any new gas resource development by 2021 and by 2026. Scenarios with the lowest probability of development are at the top of the graphs.

As can be observed from a review of Figure 3 - 10, the probability of gas development is less than 10 percent by 2021 in all but four scenarios. The only exceptions to this finding are in the **RPS at 35 percent** scenario and in scenarios where the region is unable to deploy demand response or acquires less conservation than projected. In these scenarios, the probability of moving from an option to construction on new gas-fired generation increases to 40 percent or higher.

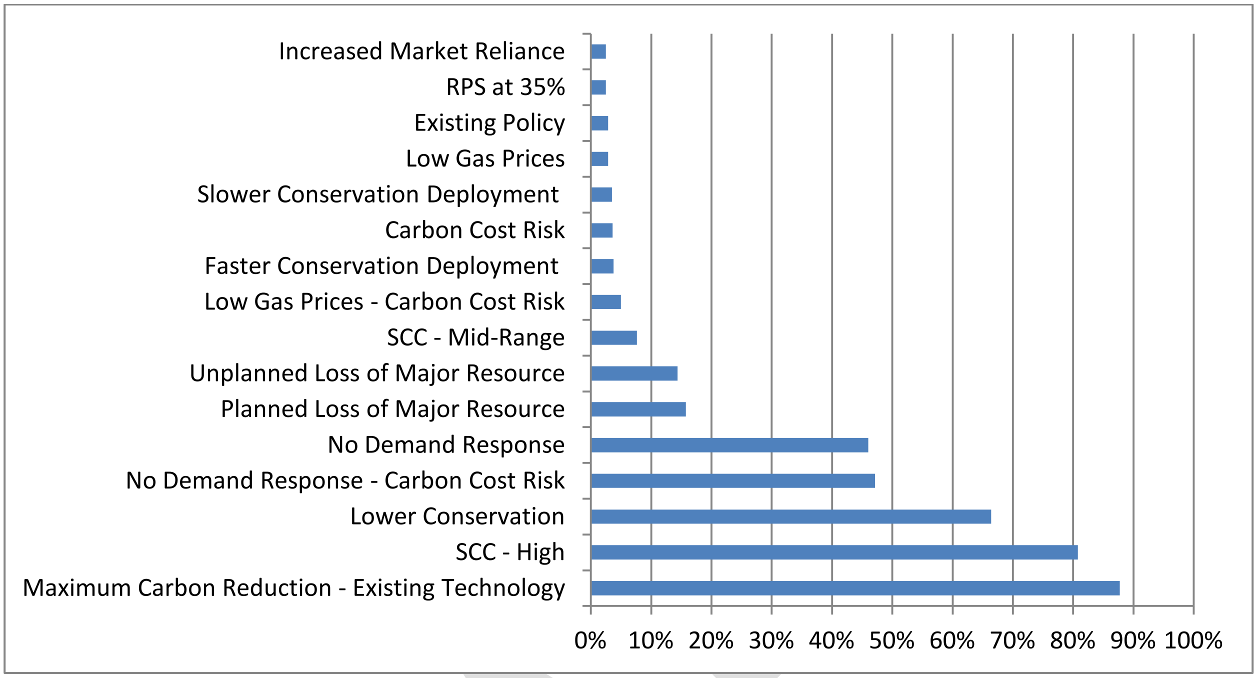
By 2026, Figure 3 - 11 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 80 percent in the **SCC-High** and **Maximum Carbon Reduction – Existing Technology** scenarios. This occurs because under both of these scenarios existing coal and inefficient gas fired generation are retired or displaced by new, highly efficient natural gas generation to reduce regional carbon dioxide emissions.

Figure 3 - 10: Probability of New Natural Gas-Fired Resource Development by 2021



The development of natural gas combined cycle combustion turbines is largest when there is a need for both new capacity and energy to meet regional adequacy standards. As can be observed from the data shown in Figures 3 - 10 and 3 - 11, this occurs in scenarios that must replace energy generation lost due to the retirement of resources, such as in the two scenarios that retire or decrease the use of existing coal and inefficient existing gas plants or those that assume no demand response resources or develop significantly less amounts of energy efficiency.

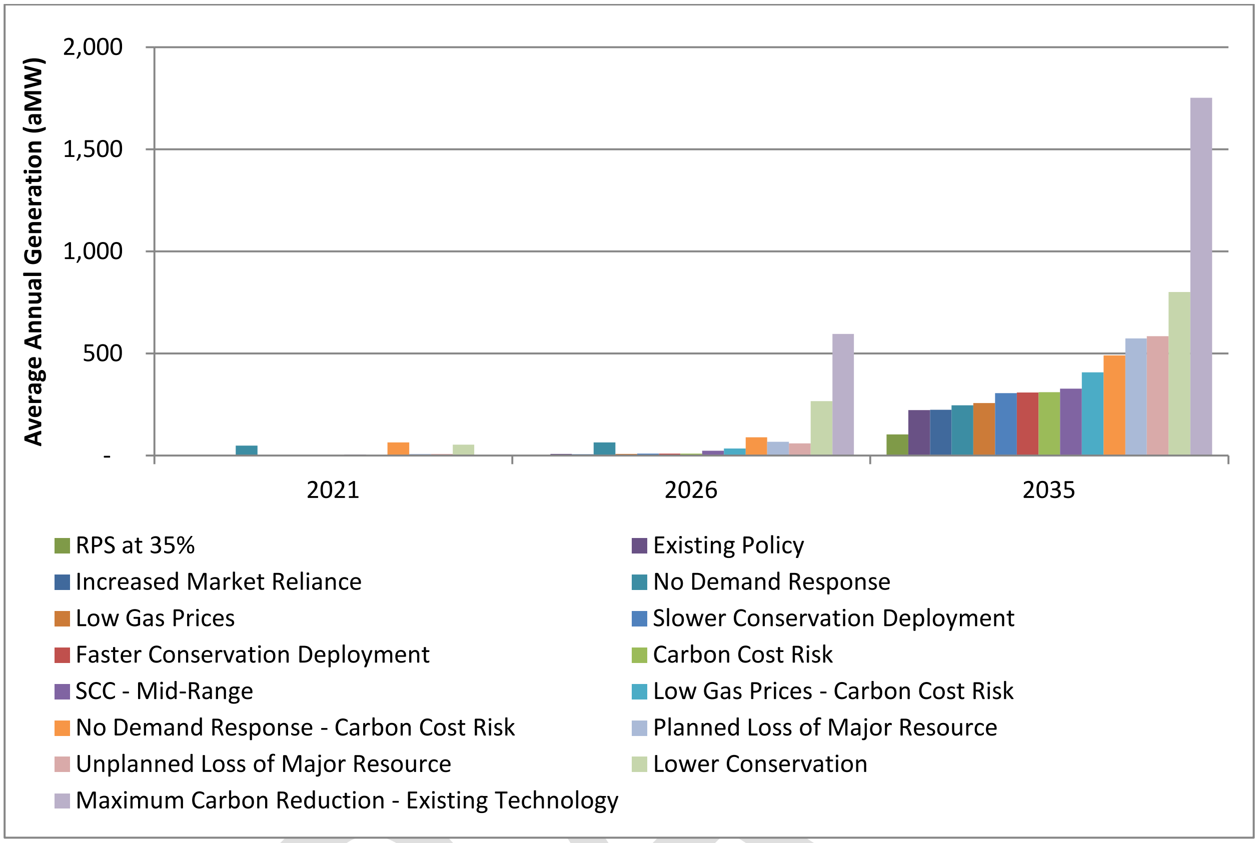
Figure 3 - 11: Probability of New Natural Gas-Fired Resource Development by 2026



As can be seen from the prior discussion, while the amounts of efficiency, demand response and renewable resources developed were fairly consistent across most scenarios examined, the future role of new natural gas-fired generation is more variable and specific to the scenarios studied. Figure 3 - 12 shows the average amounts of gas fired generation across 800 futures considered in each of the principal scenarios. The amount of new natural-gas fired generation constructed varies in each future. In most scenarios the average annual dispatch of new natural-gas fired generation is less than 50 average megawatts by 2026 and only between 300 to 400 average megawatts by 2035. In the **Carbon Cost Risk** scenario, the amount of energy generated from new combined cycle combustion turbines, when averaged across all 800 futures examined, is just 10 average megawatts in 2035. In contrast, the average amount generated across 800 futures is closer to 100 average megawatts in 2035 in the two scenarios that assume no demand response resources are developed.

However, the role of natural gas is larger than it appears in the Council's analysis of the regional need for new natural gas fired generation for a number of reasons. First, the regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. Second, some utilities have significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances even if the utilities deploy demand response resources and develop the conservation as called for in Seventh Power Plan.

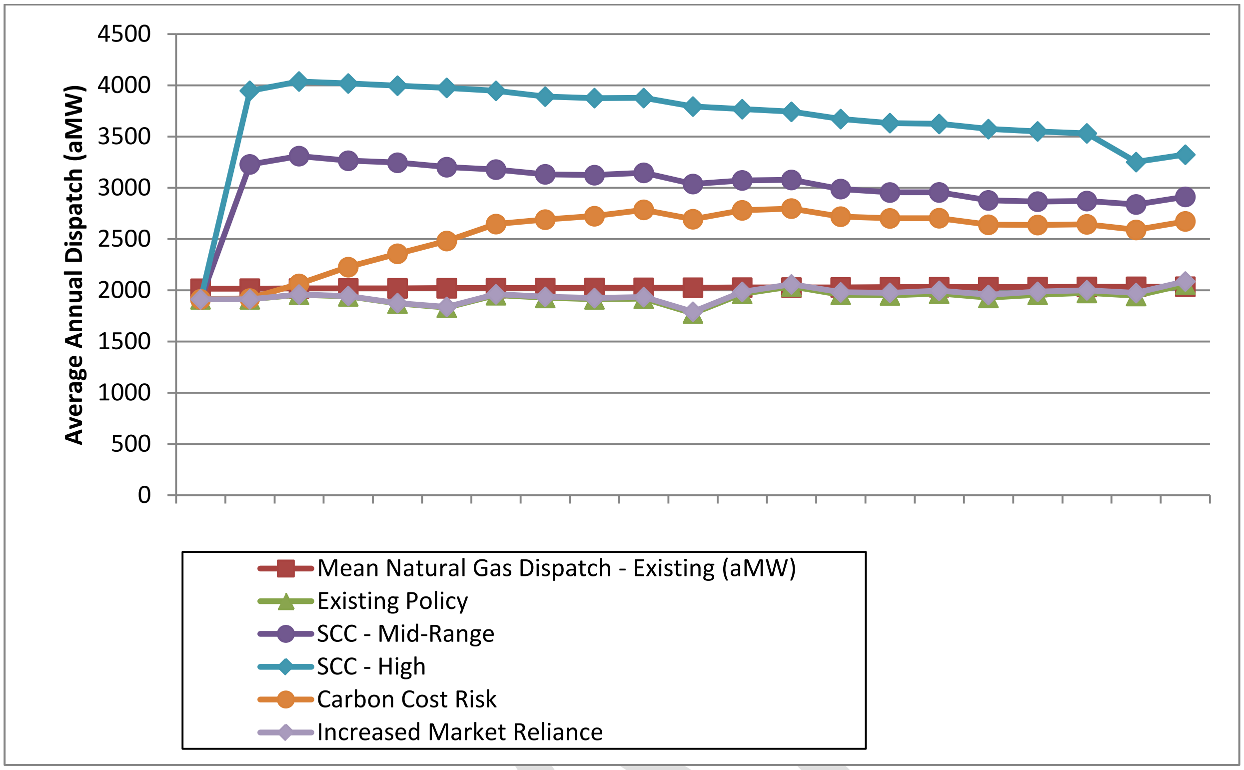
Figure 3 - 12: Average New Natural Gas-Fired Resource Development



Third, the increased use of the *existing* natural gas generation in the region plays a major role in many of scenario's least cost resource strategies, particularly those that explored alternative carbon dioxide emissions reduction policies. Figure 3 - 13 shows the average annual dispatch of the existing natural gas generation in the region through time for the five carbon dioxide reduction policy scenarios as well as the **Existing Policy** scenario. A review of Figure 3 - 13 reveals that the annual dispatch of existing natural gas generating resources increases in response to carbon dioxide emission reduction policies.

For example, under the two **Social Cost of Carbon** scenarios, existing natural gas generation increases immediately following the assumed 2016 imposition of carbon dioxide damage cost in those scenarios. In the **Carbon Cost Risk** scenario, existing natural gas generation gradually increases over time as the regulatory cost of carbon dioxide increases. In the **Maximum Carbon Reduction – Existing Technology** scenario, existing gas generation increases post-2025 when, under this scenario, the entire region's existing coal-fired generation fleet is retired. Under the **RPS at 35 percent** scenario, existing natural gas generation actually declines through time as low variable cost resources are added to the system, generally lowering market prices and diminishing the economics of gas dispatch.

Figure 3 - 13: Average Annual Dispatch of Existing Natural Gas-Fired Resources



Carbon Policies

The Northwest power system, due to its significant reliance on hydropower and its historical deployment of energy efficiency to offset the need for new thermal generation, has the lowest carbon emissions level of any area of the country. To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy efficiency resources called for in this plan. In addition, it should replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

The basis for the Seventh Power Plan's carbon policy recommendations are more fully described in the Carbon Dioxide Emissions section of this chapter.

Regional Resource Utilization

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's Seventh Power Plan resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council does not directly model the sub-hourly operation of the region's power system, both the Regional Portfolio Model and the GENESYS models presume resources located anywhere in the region can provide energy and capacity services to any other location in the region, within the limits of existing transmission. This simplifying assumption minimizes the need for new resources needed for integration of variable energy resource production. To the extent that actual systems can be developed that replicate the model's assumptions, fewer resources will be required. This likely means the region needs to invest in its transmission grid to improve market access for utilities, to facilitate development of more diverse cost-effective renewable generation and to provide a more liquid regional market for ancillary services.

As originally envisioned by the Northwest Power Act, the benefits of the FCRPS were to be shared by all of the region's consumers. However, since the Act was passed, implementing that vision has proved elusive at best and even questioned by some as desirable. Several of the scenario analyses conducted for the Seventh Power Plan reveal the symptoms and scope of this issue.

The least cost resource strategies identified by the RPM often reduce regional exports in order to serve in-region demands for energy and capacity. In particular, scenarios that retired or significantly reduced the dispatch of existing coal-fired generation serving the region, all of which serves investor-owned utilities, show lower regional exports. These resource strategies resulted in lower total system cost and lower system economic risk because they delayed or avoided the need for new resource development within the region. Figure 3 - 14 shows the average net (i.e., exports minus imports) exports for their least cost resource strategies across six scenarios.

Inspection of Figure 3 - 14 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy** scenario exports decline slightly after 2021 and 2026 following the closure of coal plants currently serving the region. After 2030, under this same scenario, net exports continue to gradually decline as loads grow and conservation no longer offsets load growth.

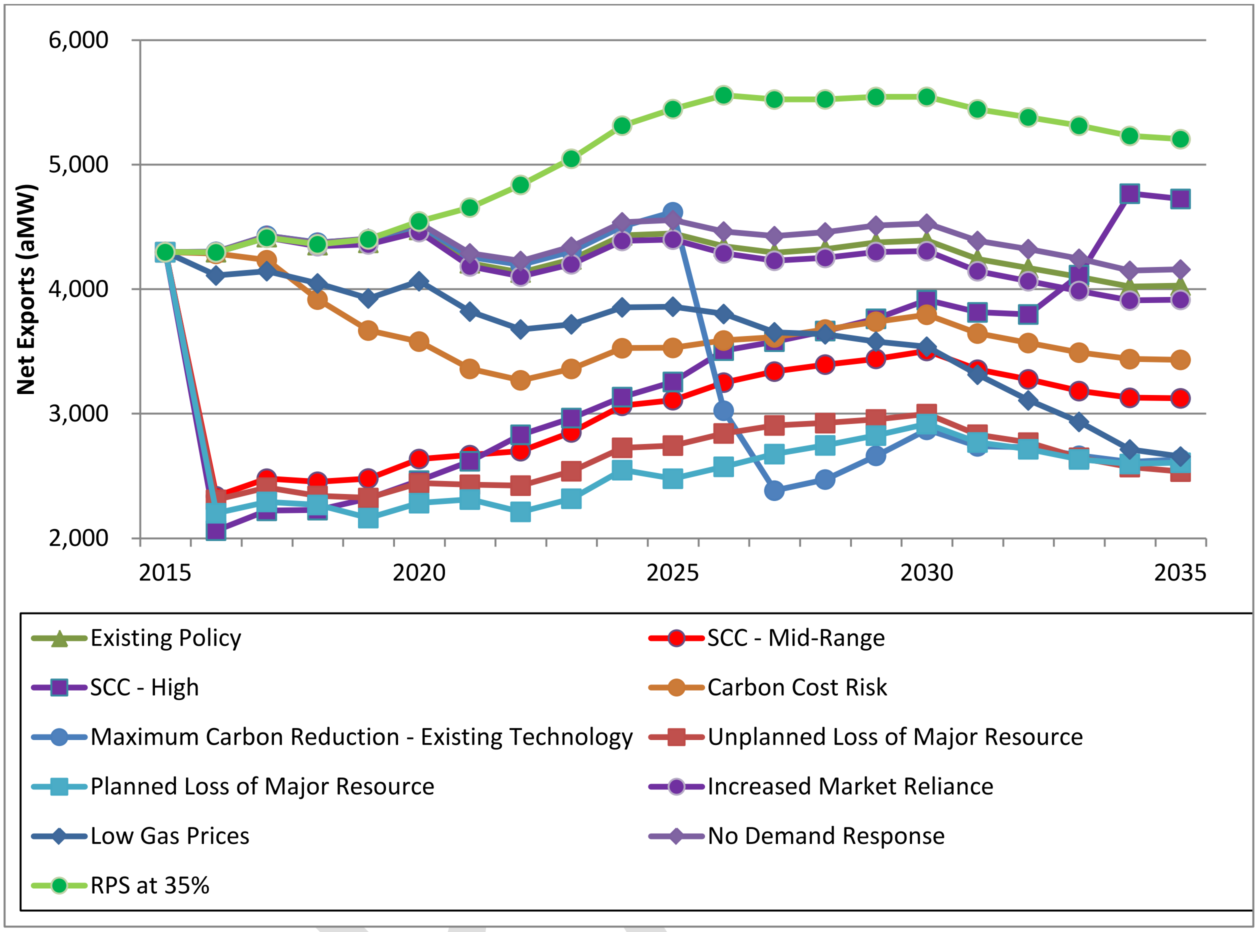
In contrast, under the two the scenarios which assume that carbon dioxide damage costs are imposed in 2016 (e.g. **SCC-Mid-Range** and **SCC-High**), net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon dioxide costs. In the following years, exports gradually increase as highly efficient gas-fired generation developed in the region displaces less efficient generation outside the region. At the other extreme, under the **RPS at 35 percent** scenario, regional net exports expand significantly over time as the region develops large amounts of wind resources. These resources have very low variable cost, which makes them competitive outside the region *and* they produce energy that is surplus to regional needs during many months of the year.

What all of these scenario results reveal is that, under a wide range of future conditions, the least cost resource strategy for the region is intimately tied to decisions made regarding the disposition of "surplus" generation. But the region's utilities and Bonneville are not all in similar load/resource balance positions. The FCRPS, except under poor water conditions, produces surplus energy beyond the firm requirements of Bonneville's public utility customers. In contrast, the region's investor-owned utilities own less hydroelectric generation so they have significantly less surplus to sell on the market.

Under the current law, investor-owned utility access to Bonneville's surplus peaking capacity is limited to seven year contracts[7] which can be terminated with five year notice.[8] While all of the region's utilities must be offered the opportunity to purchase excess Federal power, as required by the NW Power Act and within the limits of existing transmission, they must ultimately compete with out-of-region buyers for access to short-term surplus generation. If the region's investor-owned utilities do not secure access to long-term contracts at competitive prices for either energy or capacity, this will result in the need to construct new generation facilities despite the potential availability of energy and capacity resources from Bonneville.

[7] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, § 508(b), (Supp. 1 1995).
[8] Preference Act, Pub. L. 88-552, § 3(c) (1994 & Supp. 1 1995).

Figure 3 - 14: Average Annual Net Regional Exports for Least Cost Resource Strategies



Develop Long-Term Resource Alternatives

The seventh element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Seventh Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will most likely be different from those considered in the Seventh Power Plan. But the Seventh Power Plan identifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances entities in the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking and supporting the development of no-carbon dioxide or low-carbon dioxide emitting generation. The latter includes renewable technologies such as enhanced geothermal and wave energy and small modular nuclear generation.

Research, development, and demonstration of these technologies are an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and assumptions such as resource availability, cost and load growth, will identify needed changes in the power plan and near-term actions. These elements of the resource strategy are addressed primarily in the action plan.

Adaptive Management

The eighth element of the Council's resource strategy is to adaptively manage its implementation. The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. This means that during the period covered by the Seventh Power Plan's Action Plan, actual conditions must deviate significantly from the conditions tested in the 800 futures explored in the Regional Portfolio Model before the basic assumptions and action items in the Seventh Power Plan are called into question.

However, the fact that a wide range of strategies were tested against a large number of potential future conditions in developing the Plan does not mean that *all* near term actions called for in the Seventh Power Plan will be perfectly aligned with the actual future the region experiences. Therefore, the Council will annually assess the adequacy of the regional power system to identify conditions that could lead to power shortages. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions as to require adjustments to the action plan.

The Council will also conduct a mid-term assessment to review plan implementation and compare progress against specific metrics. This includes assessing how successful plan implementation has been at reducing and meeting Bonneville's obligations, both the power sales contracts and the assistance the plan's resource scheme provides in the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

CARBON DIOXIDE EMISSIONS

As in the Sixth Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon dioxide regulatory policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon dioxide reduction goal and what those changes would cost. This section summarizes how alternative resources strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency (EPA).

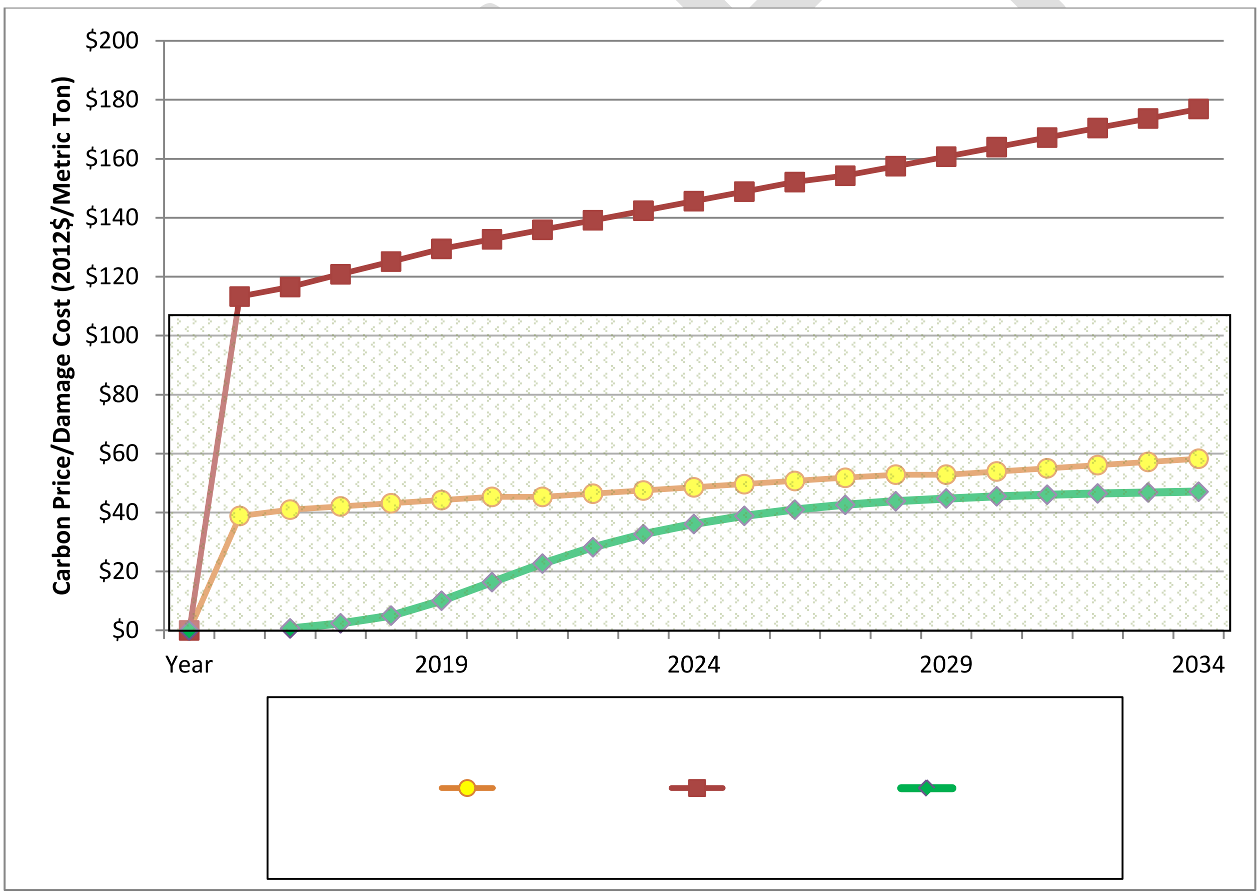
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emissions regulations. The Council's analysis is intended to provide useful information to policy-makers. Chapter 15 discusses the results of the Council's analysis of alternative carbon dioxide emissions reduction policy scenarios in more detail.

Three "carbon dioxide pricing" policy options were tested. Two scenarios assumed that alternate values of the federal government's estimates for damage caused to society by climate change due to carbon dioxide emissions, referred to as the “social cost of carbon”, are imposed beginning in 2016. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon dioxide emissions would be the maximum society should invest to avoid such damage.

The third carbon dioxide pricing policy tested, **Carbon Cost Risk** is identical to the scenario analyzed in the Sixth Plan. This scenario exposes the power system to random changes in carbon dioxide pricing each year over the 20 year planning period. This scenario was designed to reflect the uncertainty regarding future carbon dioxide regulation. In this scenario, Carbon dioxide pricing, reflecting differing levels of carbon dioxide regulatory costs, between $0 and $110 per metric ton were imposed randomly, but with increasing probability and at higher levels through time.

Figure 3 - 15 shows the two US Government Interagency Working Group’s estimates used for the **SCC - Mid-Range** and **SCC-High** scenarios and the range (shaded area) and average carbon dioxide prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Cost Risk** scenario.

Figure 3 - 15: Carbon Dioxide Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Three other carbon dioxide emission reduction policies were tested that did not involve using carbon dioxide pricing. The first of these, the **Maximum Carbon Reduction** - **Existing Technology** scenario was designed to reduce carbon dioxide emissions by deploying all currently economically viable technology. The second, the **Maximum Carbon Reduction** - **Emerging Technology** scenario was designed to reduce carbon dioxide emissions by deploying technology that may become economically viable over the next 20 years. Under both of these scenarios all existing coal plants serving the region were retired by 2026. In addition, all existing natural gas plants with heat-rates (a measure of efficiency) above 8,500 BTU/kilowatt-hour were retired by 2030. Also, in the **Maximum Carbon Reduction – Emerging Technology** scenario, no new natural gas-fired generation was considered for development.

The **Maximum Carbon Reduction – Emerging Technology** scenario was designed assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035. As stated above, the Council created this resource strategy based on energy efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative. Therefore, in the following discussion, only the impacts on carbon dioxide emissions for this scenario are reported. A more detailed discussion of the emerging technologies considered in this scenario appears in Chapter 15.

The third "non-price" carbon dioxide emission reduction policy option tested was the **RPS at 35 percent** scenario. Under this scenario, the region's reliance on carbon dioxide-free generation was increased by assuming that the region would satisfy a Renewable Portfolio Standard requiring 35 percent of the region's electricity load to be met with such resources by 2030.

In order to compare the cost of resource strategies that reflect both "carbon-pricing" and "non-carbon pricing" policy options for reducing carbon dioxide emissions it is useful to separate their cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component is the revenue collected through the imposition of carbon taxes or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the "social cost of carbon" represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these "damage costs" are borne by all of society, not just Northwest electricity consumers.

In the discussion that follows, the direct cost of resource strategies are reported separately from the carbon dioxide revenues associated with that strategy. Carbon dioxide prices or estimated damage costs are not included in the **Existing Policy**, **Maximum Carbon Reduction** - **Existing Technology** or the **RPS at 35 percent** scenarios. Therefore, only the direct cost of the least cost resource strategies for these scenarios are reported. As stated above, due to the speculative nature of the **Maximum Carbon Reduction** - **Emerging Technology** scenario no costs are reported for this scenario.

Table 3 - 1 shows the average system costs and carbon dioxide emissions for the seven scenarios and sensitivity studies conducted to specifically evaluate carbon dioxide emissions reductions policies (and economic risks) for the development of the Seventh Power Plan. This table shows the average net present value system cost for the least cost resource strategy for each scenario, both with and without carbon dioxide revenues. It also shows the average carbon dioxide emissions projected for the generation that serves the region in 2035. For comparison purposes, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 55 million metric tons from 2000 through 2012.

Table 3 - 1: Average System Costs and PNW Power System Carbon Dioxide Emissions by Scenario

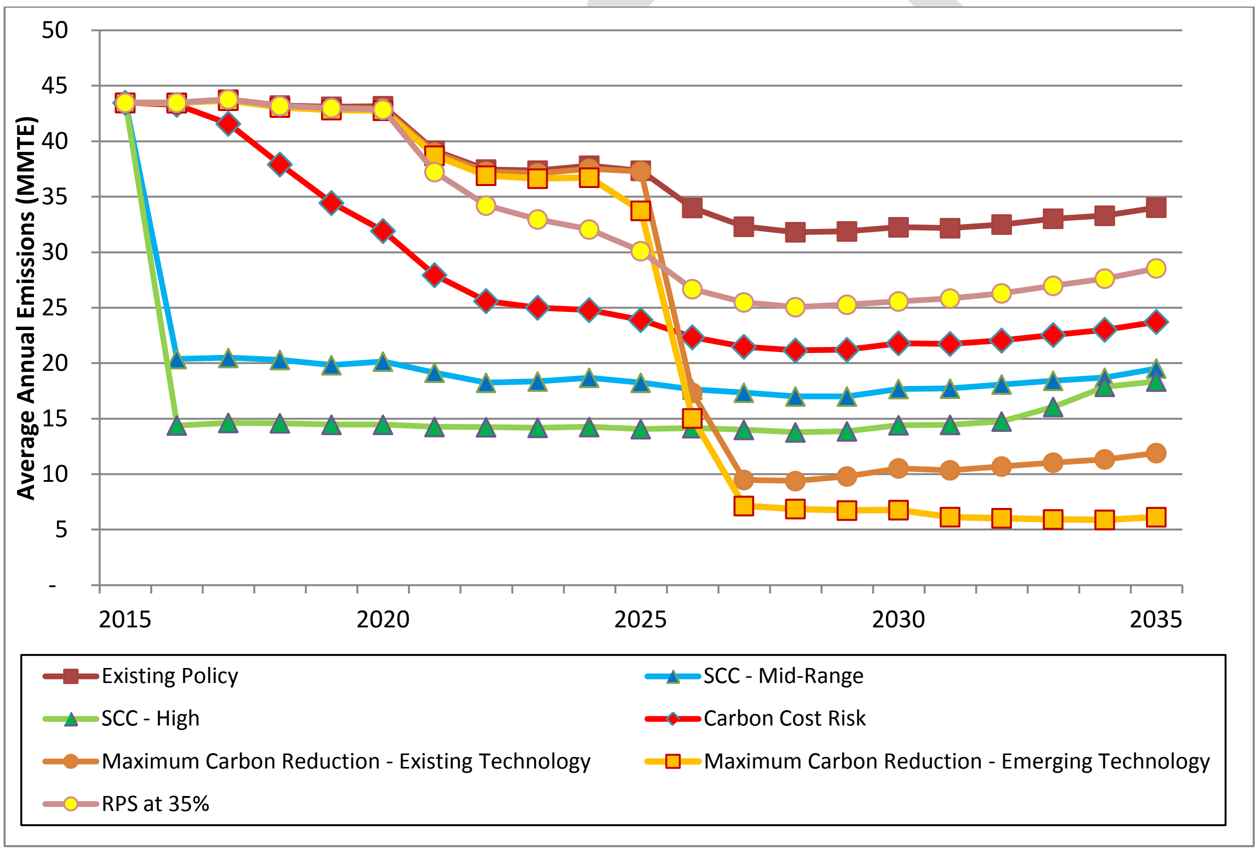
Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$	System Cost w/ Carbon Dioxide Revenues (billion 2012$)	2035 Carbon Dioxide Emissions (MMTE)
Existing Policy	$88	$88	34
SCC - Mid-Range	$89	$127	20
SCC - High	$90	$122	18
Carbon Cost Risk	$89	$115	24
Maximum Carbon Reduction - Existing Technology	$107	$107	12
Maximum Carbon Reduction - Emerging Technology	Not Calculated	Not Calculated	6
RPS at 35%	$122	$122	29

Table 3 - 1 shows the **Existing Policy** scenario which assumed no additional carbon dioxide emissions reductions policies beyond those in place prior to the issuance of the Environmental Protection Agency's Clean Air Act 111(b) and 111(d) regulations results in carbon dioxide emissions in 2035 of 34 million metric tons. The direct cost of this resource strategy is $88 billion (2012$). Three scenarios, the **SCC-Medium, SCC-High** and **Carbon Cost Risk** scenarios produce similar reductions in carbon dioxide emissions at similar costs. All three of these scenario result in carbon dioxide emissions of between 18 – 24 million metric tons in 2035 and have a direct cost of $1 - $2 billion more than the **Existing Policy** scenario's least cost resource strategy. The least cost resource strategy in the **Maximum Carbon Reduction - Existing Technology** scenario reduces 2035 carbon dioxide emissions to 12 million metric tons, or to about one-third that of the **Existing Policy** scenario. However, the estimated direct cost of this resource strategy is $20 billion, significantly higher than the **Existing Policy** scenario's least cost resource strategy. The **RPS at 35 percent** scenario's least cost resource strategy produces the least reduction in 2035 carbon dioxide emissions. Yet, this policy has the highest direct cost of all the options considered, at $34 billion more than the **Existing Policy** scenario's resource strategy. The **Maximum Carbon Reduction -**

Emerging Technology scenario reduces 2035 carbon dioxide emissions to 6 million metric tons, roughly half the emissions of the **Maximum Carbon Reduction - Existing Technology** scenario. As stated above, no costs were calculated for this scenario, due to the speculative nature of the technologies considered.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 3 - 16 shows the annual emissions level for each scenario. A review of Figure 3 - 16 reveals that the two social cost of carbon dioxide scenarios, which assume carbon dioxide damage costs are imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Power Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

Figure 3 - 16: Average Annual Carbon Dioxide Emissions by Carbon Reduction Policy Scenario



The **Carbon Cost Risk** and **RPS at 35 percent** scenarios gradually reduce emissions, while the **Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction - Emerging Technology** scenarios dramatically reduce emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon dioxide emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of carbon dioxide emitting generation.

Table 3 - 2 shows cumulative emission reductions from 2016 through 2035 for each of the carbon dioxide reduction policy scenarios compared to the **Existing Policy** scenario. It also shows the average system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide reduction policy options, net of carbon dioxide "tax revenues." Table 3-2 reveals that three carbon dioxide pricing policies have roughly comparable cost per unit of carbon dioxide emission reduction based on cumulative emissions reductions. The **Maximum Carbon Reduction – Existing Technology** scenario, as can be seen from Figure 3 - 16, results in the lowest average annual carbon dioxide emissions from the regional power system by 2035. The average cost per ton of carbon dioxide reduction for this scenario is significantly higher than the three carbon dioxide pricing policies, but much lower than average cost per ton of carbon dioxide reduction in the **RPS at 35 percent** scenario.

Note that under the two **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario, the coal plants serving the region dispatch relatively infrequently. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, and these plants are retired, then the cost of replacement resources needed to meet the energy or capacity needs supplied by the retiring plants would add to the average present value system cost of these three scenarios. As a result, the average cost of these three carbon dioxide emission reduction scenarios would likely be higher and much closer to the **Maximum Carbon Reduction - Existing Technology** scenario.

Table 3 - 2: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Dioxide Emissions Reduction Policies Compared to Existing Policies - Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMTE)	Cumulative Emission Reduction Over Existing Policy - Scenario (MMTE)	Incremental Present Value Average System Cost of Cumulative Emission Reduction Over Existing Policy - Scenario (2012$/MMTE)
Carbon Cost Risk	196	$2
SCC - Medium	360	$4
SCC - High	438	$3
Maximum Carbon Reduction – Existing Technology	217	$90
Maximum Carbon Reduction – Emerging Technology	262	Not Calculated
RPS at 35%	87	$389

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon dioxide emissions will continue beyond 2035, as will their carbon dioxide emissions impacts. These "end-effects" could alter the perceived relative cost-efficiency of carbon dioxide reduction policy options shown in Table 3 - 2. For example, over a longer period of time the cumulative emissions reductions from the **Maximum Carbon Reduction – Existing Technology** scenario could exceed those from the **SCC-Mid-Range** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 8 MMTE per year lower emissions. In this instance, if the difference in emissions rates for these two scenarios were to remain the same for an additional 20 years, then their cumulative emissions reductions over 40 years would be nearly identical. Since it is impossible to forecast these "end effects," readers should consider the scenario modeling results shown in Table 3 - 2 as directional in nature, rather than precise forecast of either emissions reductions or the cost to achieve them.

The key findings from the Council's assessment of the potential to reduce power system carbon dioxide emissions are:

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, or by nearly 80 percent. Achieving this level of carbon dioxide emission reduction is nearly $20 billion or more than 23 percent above the cost of the least cost resource strategies that are anticipated to comply *at the regional* level with the newly established federal emissions limits.
- With forecast development and deployment of current emerging energy efficiency and non-carbon emitting resource technologies it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, or to about 50 percent below the level achievable with existing technology. The cost of achieving this level of emissions was not estimated due to the speculative nature of the technologies considered in this scenario.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.
- Deployment of variable output renewable resources at the scale considered in the Maximum Carbon Reduction – Emerging Technology scenario presents significant power system operational challenges.

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning development the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments the EPA issued it final Clean Power Plan (CPP) rules. The "111(d) rule," referred to by the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants, has a goal of reducing national power plant carbon dioxide emissions by 32 percent from 2005 levels by the year 2030.

This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. EPA also issued the final rule under the Clean Air Act section 111(b) for new power plants and the proposed federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the rule requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in carbon dioxide emissions. The eight year interim compliance period is further broken down into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal.

Under the EPA's final rules, states may comply by reducing the average carbon dioxide emission rate (pounds of carbon dioxide/kilowatt-hour) emitted by all power generating facilities located in their state that are covered by the rule. In the alternative, states may also comply by limiting the total emissions (tons of carbon dioxide per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option EPA has set forth two alternative limits on total carbon dioxide emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon dioxide emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach not only better represents the total carbon dioxide footprint of the power system, but it more fully captures the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 3 - 3 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 3 - 3: Pacific Northwest States Clean Power Plan Final Rule Carbon Dioxide Emissions Limits[9]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically located within the regional boundaries defined under the Northwest Power Act[10]. In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's carbon dioxide emissions limits to those specifically covered by the agency's regulations, it was necessary to model a sub-set of plants in the region.

Under the Clean Air Act, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest Power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from the state level to the regional level is also shown in this figure (top heavy line).

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[9] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 3-2 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

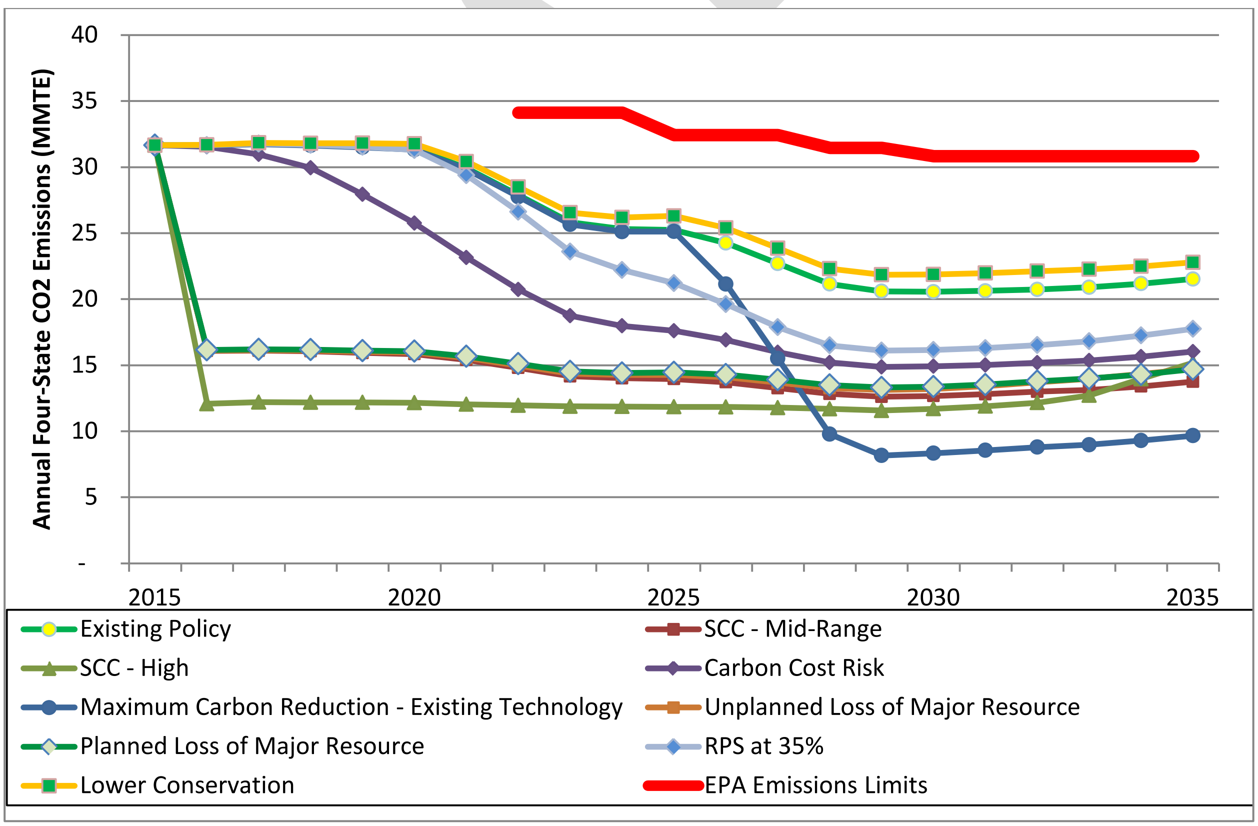
[10] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

Figure 3 - 17 shows all of the scenarios evaluated result in average annual carbon dioxide emissions well below the EPA limits for the region.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon dioxide emissions rule should be achievable without adoption of additional carbon dioxide reduction policies in the region. This is not to say that no additional action need occur.

All of the least cost resource strategies that have their emission levels depicted in Figure 3 - 17 call for the development of between 4,000 and 4,600 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios would increase emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets.

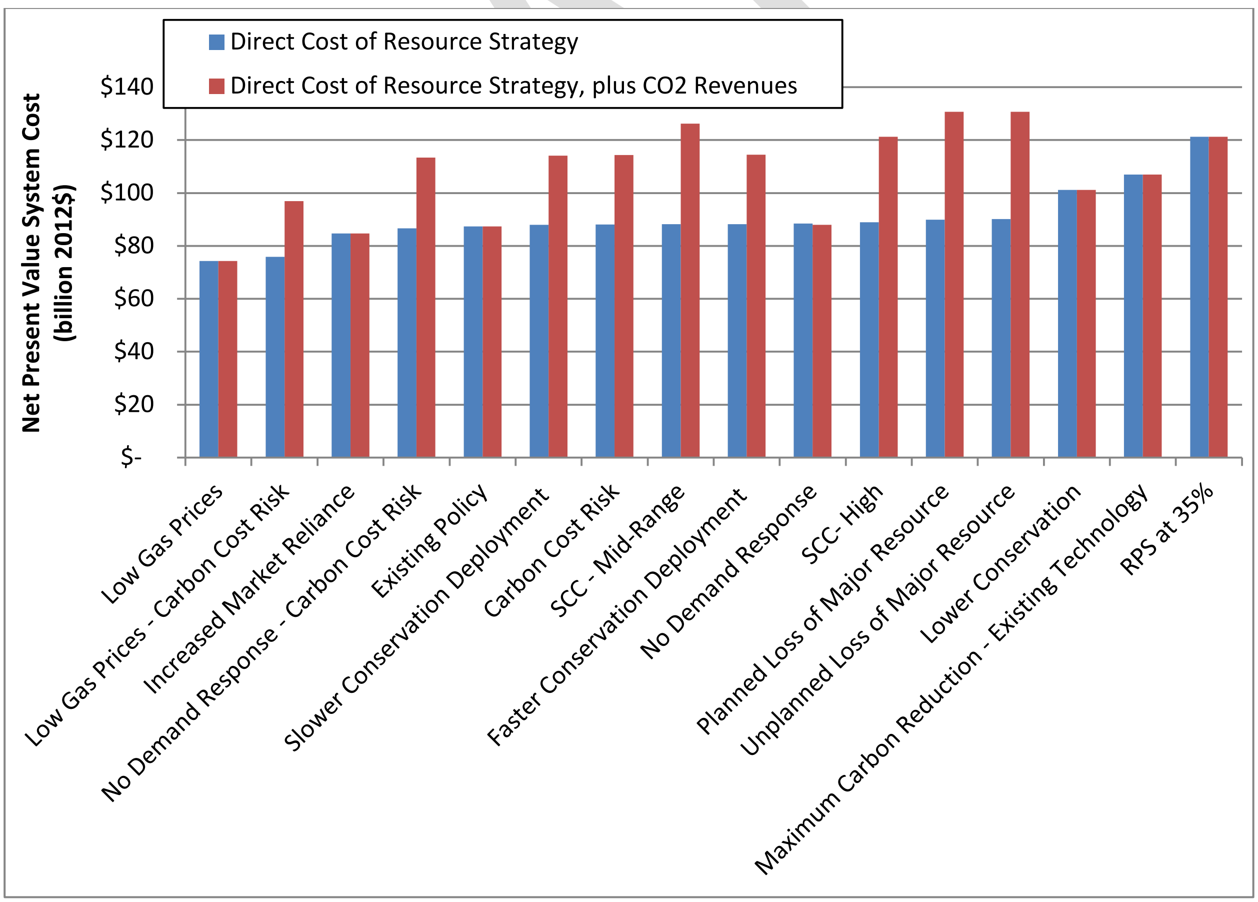
Figure 3 - 17: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



RESOURCE STRATEGY COST AND REVENUE IMPACTS

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy it tests to identify those strategies that have both low cost and low economic risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 3 - 19 shows the present value system cost for the principal scenarios evaluated during the development of the Seventh Power Plan. Figure 3 - 18 also shows the present value of power system costs both with and without assumed carbon dioxide emissions costs. That is, the scenarios that assumed some form of carbon dioxide price include not only the direct cost of building and operating the resource strategy, but also the costs of emitting carbon dioxide assumed in those scenarios. Therefore, in Figure 3 - 18 the present value system cost of the least cost resource strategies for the scenarios that do not assume that either carbon dioxide regulatory cost risk or damage cost are the same with and without consideration of carbon dioxide costs. For example, the average system cost for the **Low Gas Price and Existing Policy** scenarios are the same with or without considering carbon dioxide revenues.

Figure 3 - 18: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Cost



Inspection of Figure 3 - 18 shows that, exclusive of carbon dioxide costs, the average net present value system cost for the least cost resource strategies across several of the scenarios are quite similar.

Table 3 - 4 shows that only four scenarios, the **Maximum Carbon Reduction - Existing Technology**, **Increased Market Reliance, Lower Conservation** and **RPS at 35 percent** scenarios, have average system costs that differ significantly from the **Existing Policy** scenario. This is due to the fact that with the exception of these four scenarios, the least cost resource strategies across the other scenarios are similar.

The **Maximum Carbon Reduction – Existing Technology** scenario differs from the others because it assumes that all of the coal plants that serve the region are retired as well as existing gas generation with heat rates over 8,500 Btu/kilowatt-hour. As a result, the present value system cost is significantly increased by the capital investment needed in replacement resources, largely new combined-cycle combustion turbines. The least cost resource strategy under the **Lower Conservation** scenario develops about 1200 average megawatts less energy savings and 2900 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $14 billion higher because it must substitute more expensive generating resources to meet the region's needs for both capacity and energy. Under the **Renewable Portfolio Standard at 35 percent** scenario, the increase in average present value system cost stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs.

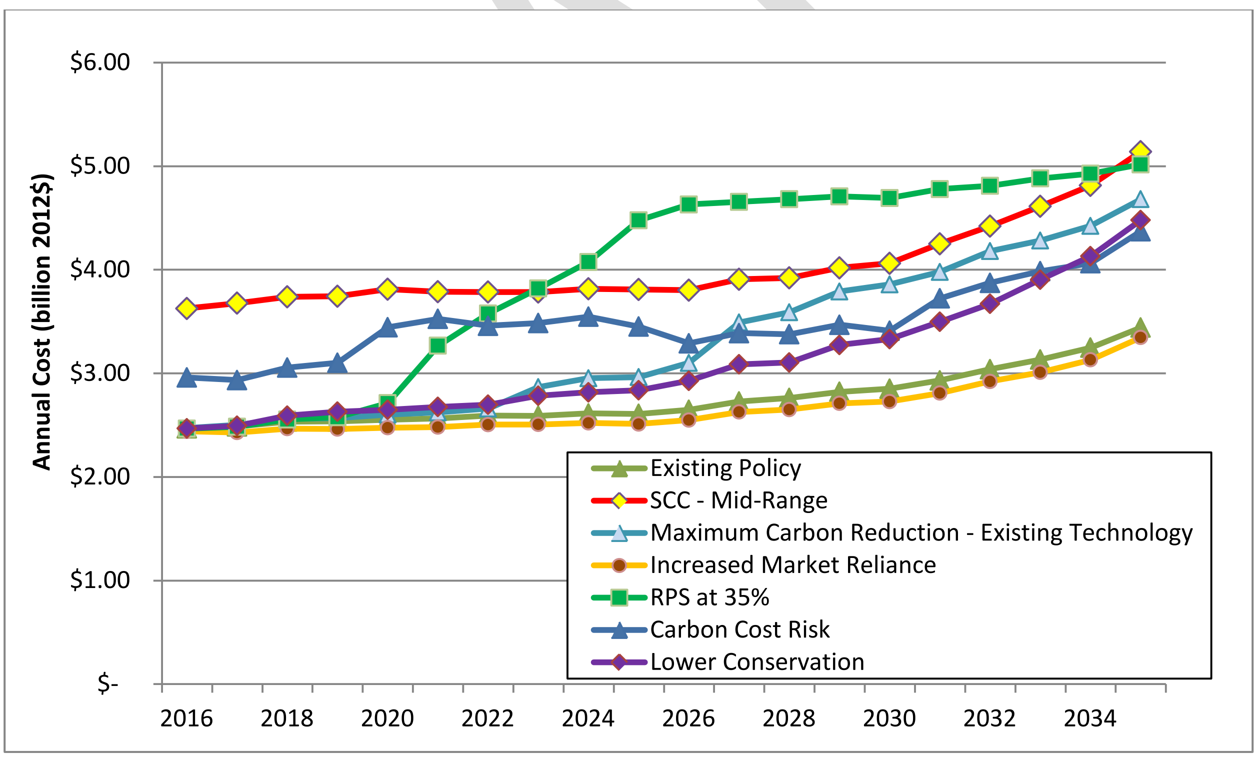
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

Scenario	Present Value System Cost of Resource Strategy (billion 2012$)	Incremental Present Value System Cost Over Existing Policy Scenario Resource Strategy (billion 2012$)
Existing Policy	$88	
Social Cost of Carbon - Base	$89	$0.8
Social Cost of Carbon - High	$90	$1.5
Carbon Cost Risk	$89	$0.7
Maximum Carbon Reduction – Existing Technology	$107	$19.1
Unplanned Loss of Major Resource	$91	$2.8
Planned Loss of Major Resource	$91	$2.5
Faster Conservation Deployment	$89	$0.8
Slower Conservation Deployment	$89	$0.6
Increased Market Reliance	$85	($2.7)
RPS at 35%	$122	$33.9
Lower Conservation	$102	$13.8

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Four of the scenarios assume no carbon dioxide regulatory compliance cost or damage costs**: Existing Policy, Maximum Carbon Reduction - Existing Technology, Lower Conservation** and **Renewable Portfolio Standards at 35 Percent** so their forward going costs are identical with and without carbon dioxide cost. In order to compare the direct cost of the actual resource strategies resulting from carbon dioxide pricing policies with these four scenarios it is necessary to remove the carbon dioxide cost from those other scenarios. Figure 3 - 20 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon dioxide costs.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 3 - 19 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the two Social Cost of Carbon scenarios and the Carbon Cost Risk scenario include the cost of carbon dioxide regulation or carbon dioxide damage.

Figure 3 - 19: Annual Forward-Going Power System Costs, Excluding Carbon Dioxide Revenues

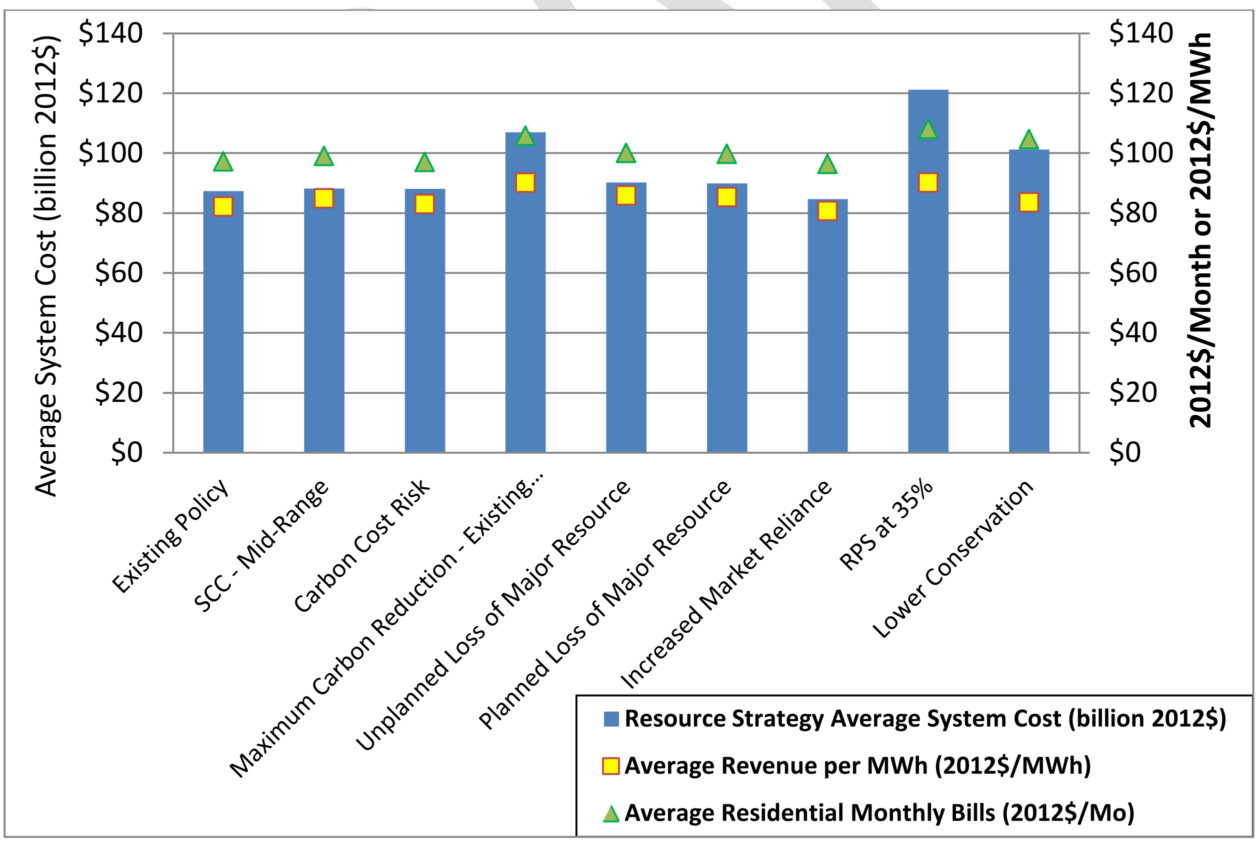


A review of Figure 3 - 19 shows that the **Carbon Cost Risk** and **Increased Market Reliance** scenarios have slightly lower annual cost post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35 percent and Maximum Carbon Reduction - Existing Technology** least cost resource strategies. The highest forward going revenue requirement, well above even the **Maximum Carbon Reduction - Existing Technology** scenario's least cost resource strategy is the Increase Renewable Portfolio Standard. This strategy's high cost is due to not only to the high cost of renewable resources, but the cost of thermal resources that must still be added to the system to ensure winter peak needs are met.

In the following section of this chapter these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects of some of the scenarios.

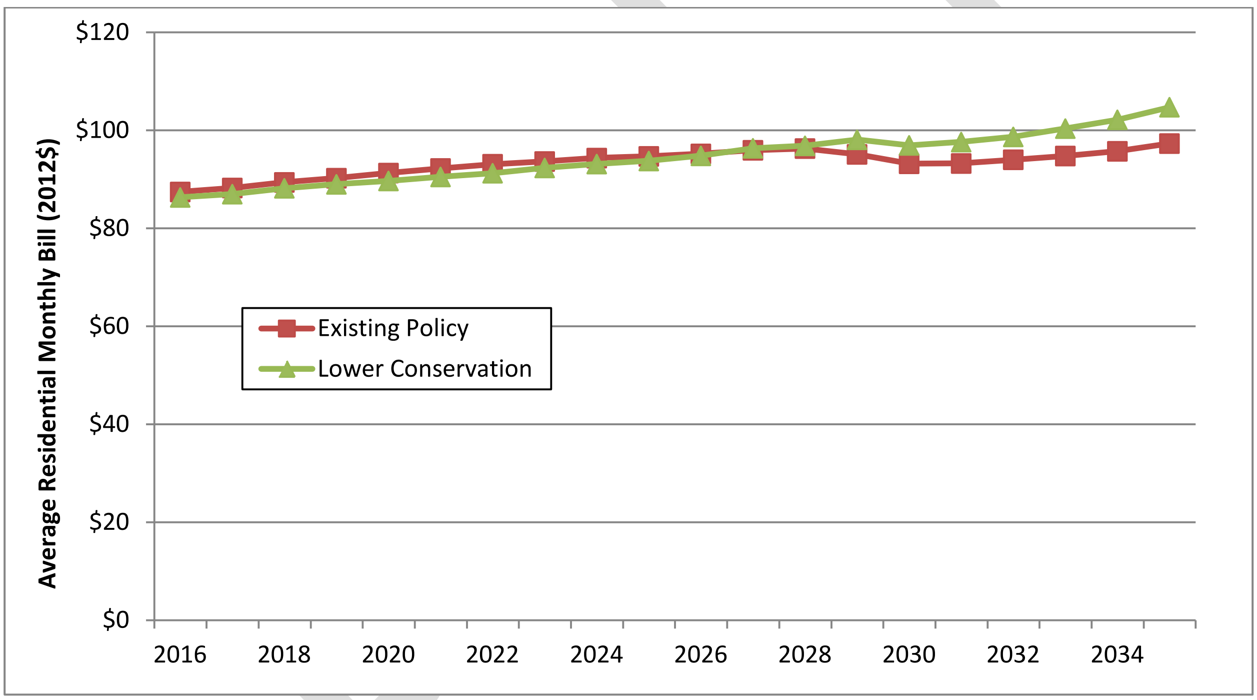
Figure 3 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 3 - 20 are average revenue requirement per megawatt-hour which include both monthly fixed charges and monthly energy consumption charges. The residential bills are typical monthly bills. In order to compare these scenarios over the period covered by the Seventh Power Plan, both the average revenue requirement per megawatt-hour and average monthly bills have been levelized over the twenty year planning period. Both are expressed in constant 2012 dollars.

Figure 3 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Dioxide Revenues



As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the lower-conservation scenario. The **Lower Conservation** scenario has an average system cost of $101 billion, compared to the **Existing Policy** resource strategy's $87 billion. Even with nearly a $14 billion higher average system cost the **Lower Conservation** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirement per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy** scenario and $84 per megawatt-hour for the Lower Conservation scenario. However, **the Lower Conservation** scenario's average monthly bill is about $105, about $6 per month higher than **the Existing Policy** scenario's average monthly bill of $99. This illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 3 - 21 illustrates how the greater efficiency improvements lower average electricity bills.

Figure 3 - 21: Residential Electricity Bills With and Without Lower Conservation



CHAPTER 4: ACTION PLAN

Contents

INTRODUCTION

The action plan describes things that need to happen in order to implement the Council's Seventh Power Plan. It focuses on the next six years and the priorities in the plan. The Action Plan starts with activities that comprise the Regional Resource Strategy. The following three sections set forth actions that the Region, the Bonneville Power Administration and Council itself should undertake to support implementation of the Seventh Plan. The final section describes activities that the Council will engage in to maintain and enhance its analytical capabilities. In many cases, the action plan suggests the entities that have primary responsibility for implementation activities and a time frame for completion of the action.

RESOURCE STRATEGY

Energy efficiency is the first priority resource in the Northwest Power Act. The Council's analysis for the Seventh Plan affirmed that energy efficiency improvements provide the most cost-effective and least risky response to the region's growing electricity needs. Further, acquisition of cost-effective efficiency reduces the contribution of the power system to greenhouse gas emissions. While many new sources of carbon-free electricity are available, they are currently more expensive and provide little winter peaking capacity. The acquisition of cost-effective efficiency will also buy time to develop cost-effective alternative sources of carbon-free generation.

Over the past decade the region has successfully accomplished conservation, exceeding both the Fifth and Sixth Plan's goals. Nevertheless, achieving the level of conservation identified in the Seventh Plan will require continued aggressive actions by the region. While the aggressive pursuit of new conservation is the primary focus of the Regional Resource Strategy for the next six years, the second priority is to develop the ability to deploy demand response resources to meet system capacity needs under critical water and weather conditions.

After energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions and replacing retiring coal generation. Moreover, it is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term.

At the regional level, the probability that new natural gas-fired generation will be needed to supply winter peaking capacity prior to 2021 is quite low. However, the Seventh Plan recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require near-term investments in generation resources to provide reliable electricity supplies in specific utility balancing areas. In addition, individual utilities have varying degrees of access to electricity markets and varying resource needs. The Council's regional power plan is not necessarily a plan for every individual utility in the region, but is intended to provide guidance to the region on the types of resources that should be considered and their priority for development.

Combined development of improved efficiency, demand response, renewable generation as required by state renewable portfolio standards and the increased use of existing natural gas generation, will help delay investments in more expensive and carbon emitting forms of electricity generation until state and regional carbon dioxide emission reduction compliance plans are developed and implemented and alternative low-carbon energy technologies become cost-effective.

Resource Strategy Action Items

The Council recommends that the region pursue the following actions to implement the Seventh Plan's resource strategy:

RES-1 **Achieve the regional goal for cost-effective conservation resource acquisition.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA and States] Conservation programs and budgets should be designed to achieve savings based on the schedule shown below. Cumulative accomplishments, starting with savings acquired in FY2016, should achieve a minimum conservation goal of 1400 aMW by 2021, 3100 aMW by 2026 and 4500 aMW of cost-effective conservation by 2035. The Council will monitor achievement of cost-effective savings annually to assess progress towards both the biennial milestones detailed below and longer-term goals. Expected savings in excess of Sixth Plan targets prior to 2016 have been taken into account in setting the goals below and do not count towards meeting these targets. Savings achieved in excess of the biennial milestones below should be considered part of the next biennial progress toward the conservation goals.

Conservation Energy Milestones by Fiscal Year in Average Megawatts

	FY16-17	FY18-19	FY20-21	FY22-23
Annual Energy	370	460	570	660
Cumulative Energy	370	830	1400	2060

RES-2 **Evaluate cost-effectiveness of measures using methodology outlined.** [RTF, Bonneville, NEEA, Utilities, Energy Trust of Oregon] To determine if a measure is cost-effective, from a total resource cost basis, and in order to ensure that the cost-effectiveness formulation incorporates the full capacity contribution of measures and risk avoidance, regional utilities should use the methodology described in Appendix G: Conservation Resources and Direct Application Renewables. This method assures that all the costs and benefits are captured, that the time-dependent shape of the savings are accounted for, and that the capacity contribution of the measures are fully taken into account.

RES-3 **Develop and implement methods to identify system specific least-cost resources to maintain resource adequacy.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA, and States] The Seventh Plan's analysis identified a potential need to add resources, including conservation and demand response, to maintain an adequate and reliable system. The Council's resource strategy includes guidance to Bonneville and the region's utilities on what resources would meet these needs at the least cost from a regional perspective. However, it is not possible in the Council's regional plan to specify exactly when additional resources will be needed or which resources and in what amounts best match the needs of individual entities. While the Council will continue to analyze these issues from a regional system perspective, the region's utilities and Bonneville should develop and implement methods to evaluate resource decisions to maintain resource adequacy. These methods should be consistent with the Council's Seventh Plan and with the Council's annual Resource Adequacy Assessment. To consider all potentially available resources including conservation and demand response these methods should:

- Include an assessment of whether additional conservation acquisitions, beyond the levels set forth in RES-1, would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Include an assessment of whether demand response would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Evaluate cost-effectiveness by comparing the cost of increasing conservation acquisition and demand response to the cost of resources that add to regional reliability, such as additional thermal generation resources, rather than to short-term market purchases (e.g. RES-2),
- Consider thermal generation resources especially when local transmission congestion or provision of ancillary services provide added benefits, and
- Assess the individual positions of Bonneville or the utility with regard to the contribution to individual and regional reliability.

The Bonneville Resource Program following the next Council Resource Adequacy Assessment (scheduled for 2016) should outline an approach and schedule to accomplish this action item. Utility integrated resource plans developed after the next Resource Adequacy Assessment should also include comparable approaches.

RES-4 **Expand regional demand response infrastructure.** [Utilities that dispatch resources, Utility Regulators, Bonneville and States] Utilities and Bonneville should begin to or continue to develop or contract for systems to enable rapid expansion of demand response programs targeting winter or summer peaks relative to their individual system needs as assessed in RES-3. Such contracts and/or systems should be capable of integrating demand response into utility dispatch and operations and should be tested to verify that they can provide reliable demand reductions. These systems should be in place prior to the announced retirement date of existing coal generation facilities in the region and be maintained as a resource for deployment under low-water, high-load conditions or other times of system stress.

RES-5 **Support regional market transformation for demand response.** [NEEA, Utilities that dispatch resources, Utility Regulators, Bonneville and States] Regional market transformation efforts and techniques should be used to reduce the cost and expand the availability of products that exist on the customer-side of the meter that could serve as demand response resources. The region has a proven track record of working with manufacturers and engaging in standards and code processes to reduce the cost and increase the market penetration of energy efficient products. These same approaches should be applied to demand response. For example, including demand-response ready controls in regional market transformation initiatives for energy efficiency in consumer appliance and lighting controls could accelerate the ability to develop automated demand response resources employing those products. A systematic approach to market transformation should be well established two years in advance of the next power planning process.

RES-6 **Meet existing Renewable Portfolio Standards (RPS).** [Utilities, Utility Regulators, and States] Utilities should continue to comply with existing state Renewable Portfolio Standards. Developing renewable resources that exceed RPS should be done with due consideration of RES-3 and RES-8. The Council will review utility Integrated Resource Plans and state compliance processes to track renewable resource development under state RPS.

RES-7 **Expand renewable generation technology options considered for Renewable Portfolio Standards (RPS) compliance.** [Utilities, Utility Regulators, and States] Utilities should assess the cost and generation potential for utility-scale solar photovoltaic technologies when developing strategies to comply with existing state Renewable Portfolio Standards. Each utility should consider its own cost and resource need profile in such assessments. The Council will review utility Integrated Resource Plans and state compliance processes to track the types of renewable resources developed under state RPS.

RES-8 **Regional carbon emissions.** [Utilities, Bonneville, Utility Regulators, and States] The Council did not evaluate resource strategies for state level compliance with the Environmental Protection Agency's Clean Power Plan (Clean Air Act, Sections 111(b) and 111(d)) carbon dioxide emissions limits. However, analysis for the Seventh Plan found that compliance was highly probable *at the regional level* through the reductions in emissions from coal-plants that are already scheduled for retirement, by achieving the regional conservation goals set forth in RES-1, by satisfying existing state Renewable Portfolio Standards and by re-dispatch of existing gas-fired generation. Should individual states or the region seek further emissions reductions, the least cost resource strategies identified by the Council rely on the re-dispatch of both existing coal and natural gas generation, rather than increased use of renewable resources that do not supply winter capacity.

RES-9 **Adaptive Management.** [Council, Utilities, Bonneville, Utility Regulators, and States] In order to track Seventh Plan implementation and adapt as needed the Council, in cooperation with regional stakeholders, will provide:

- Annual Resource Adequacy Assessments
- Annual Conservation and Demand Response Progress Reports
- Mid-Term Assessment of Plan Implementation and Planning Assumptions

Regional Actions Supporting Plan Implementation

The Council recommends that the region pursue the following actions to implement the Seventh Plan:

REG-1 **Develop robust set of end-use load shapes with plan to update over time.** [Council, Bonneville, NEEA, Utilities, Energy Trust of Oregon] The capacity value of energy-efficiency measures is significant. Data on new and emergent loads, including stand-by loads, however, is lacking. Additionally, where no more recent data is available, many of the end-use load shapes used in the Seventh Plan were developed 30 years ago. The region needs to update these load shapes to better understand peak contributions. Completion of this action will result in a data set of hourly (8760 hours per year) load shapes for a wide variety of end-uses and building segments. A business case for this study was completed for the Regional Technical Forum in 2012. Improvements in technology and opportunities for out-of-region coordination should reduce the cost of updating load shapes as compared to the 2012 business case. An update of the business case, specific work plan for implementation, and funding secured to accomplish this study should be completed by the end of 2016. Priority should be given for end-use load shapes that impact winter peak and to fill significant gaps in existing end-use load shape data.

REG-2 **Provide continued support for the Northwest Energy Efficiency Alliance (NEEA).** [Bonneville, Utilities, and Energy Trust of Oregon] Provide continued support for NEEA's 2015-2019 strategic and business plans. Consider additional support for NEEA to provide regional leadership on new opportunities where NEEA's core competencies, economies of scale and risk mitigation provide maximum value to the region. Identify and adopt new initiatives, and facilitate strategic planning efforts among partners to implement conservation opportunities identified in the Seventh Plan. Market transformation initiatives implemented by NEEA may need to be revised or expanded to encompass changing markets and the rapid progress in energy codes and standards. Specific action items in the Seventh Plan for which NEEA is the lead implementer include:

Activities within the existing scope of NEEA's 2015-2019 Strategic and Business Plans:

- REG-10. Develop strategies to coordinate energy-efficiency planning within region.
- MCS-4. Develop a regional work plan focusing on emerging technologies to help ensure adoption.
- REG-7. Conduct regional sector-specific stock assessments.
- MCS-7. Monitor and track code compliance in new buildings.
- REG-8. Understand the impact of codes and standards on load forecasting and regional conservation targets.

New activities not included in NEEA's 2015-2019 Strategic and Business Plans:

- MCS-6. Develop and deploy best-practice guides for the design and operations of new and emerging industries, such as data centers.

- ANLYS-1. Develop robust set of end-use load shapes with plan to update over time.
- ANLYS-6. Prioritize research and adoption of energy-efficiency measures that also save water.
- RES-5. Support regional market transformation for demand response.

REG-3 **Collaborate on demand response data collection.** [Utilities, Bonneville and Utility Regulators] To assist with regional power planning, utilities should include the following information in their Integrated Resource Plans and Bonneville in its Resource Program:

- Data (date and amount) on the historic dispatch of demand response (DR)
- Future plans for DR acquisition, including an assessment of the system need (e.g., winter capacity, wind integration, etc.) that DR is anticipated to meet
- Assessment of DR potential within the utility's service territory

REG-4 **Collaborate on collection of regional operating reserve planning data.** [Utilities, Bonneville, and Utility Regulators] Utilities should include their planning assumptions for the provision of operating reserves in their Integrated Resource Plans and Bonneville in its Resource Program. These assumptions should emphasize reliability ahead of economic operations, that is, reasonable estimates for times of power system stress. The following should also be included :

- An estimate of the utility's or Bonneville's requirement for operating reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on hydropower generation and which projects should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on thermal plants and which plants should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for any third-party provision of reserves

REG-5 **Conduct regular conservation program impact evaluations to ensure that reported energy and capacity savings are reliable.** [Bonneville, RTF, Energy Trust of Oregon, Utilities, Utility Regulators] Implementation of cost-effective energy efficiency is a key element of all least-cost resources strategies where energy efficiency is the single largest system investment in new resources. As such, the region needs to assure the implementation of efficiency programs produces reliable, cost-effective energy and capacity savings. The Regional Technical Forum should maintain and update its program impact evaluation guidelines and standards to ensure the reliability of energy and capacity savings reported and to inform the adaptive management of energy savings programs going forward. Bonneville, utilities, Energy Trust of Oregon, and regulators should assure effective evaluations of the energy and capacity impacts of programs occur on a regular basis. The Regional Technical Forum should track these evaluated savings in its regional conservation progress report.

REG-6 **Report on progress toward meeting Seventh Plan conservation objectives including the contribution of conservation to system peak capacity needs.** [RTF, Council, Bonneville, Utilities, Energy Trust of Oregon, and NEEA] As part of the

Council's review of Seventh Plan implementation, the Regional Technical Forum should collect data annually from Bonneville, Utilities, Energy Trust of Oregon, and NEEA to report on progress towards meeting the plan's conservation targets and objectives. This Regional Conservation Progress Report should address whether and how the conservation technologies and practices identified in the plan are being developed for acquisition through local utility programs, coordinated regional programs, market transformation, adoption of codes and standards, code compliance efforts, and other mechanisms. The report should incorporate results of program impact evaluation and identify any acquisition gaps that need to be addressed. Given the importance of the capacity contribution of conservation identified in the Seventh Plan analysis, the report should also include estimates of the contribution of conservation to system peak capacity needs.

REG-7 **Conduct regional sector-specific stock assessments.** [NEEA] The stock assessments are a valuable resource for individual utilities and the region and should be updated regularly. Updated data should be available by early 2020, in time to inform the development of the Eighth Plan. Continue to enhance and improve the residential, commercial, and industrial assessments with regional review and input. Add an agricultural stock assessment that would improve understanding of opportunities in that sector, recognizing current data collection activities by Bonneville and difficulties in acquiring needed data. Currently, only the residential and commercial assessments are built into the NEEA 2015 through 2019 business plan, but there is significant value in collecting data for the industrial and agriculture sectors as well. Efforts in these sectors require coordination with stakeholders to establish the appropriate data collection methods. NEEA should define a schedule for designing and executing these assessments with a goal of having data available for all sectors by early 2020.

REG-8 **Reflect the impact of codes and standards on load forecast and their contribution to meeting regional conservation goals.** [NEEA, Utilities, Energy Trust of Oregon, Bonneville, National Labs] NEEA should track the savings impact of enacted codes and standards and collect the necessary data, such as saturation of appliances, number of units installed, and unit savings. These savings impacts can then be included in load forecasts and may be claimed against savings goals. NEEA should leverage the work Bonneville has completed to quantify the impacts of federal standards adopted since the development of the Sixth Plan. NEEA should produce an annual report on the savings impact of standards and updated models to link savings and load forecast estimates.

REG-9 **Use whole-building consumption data to improve energy and demand savings acquisitions and estimates.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, Trade Allies, Evaluators, Regulators] Utilities should exploit the greater availability of interval data and analytic tools to improve estimates of both energy and demand savings and encourage facilities to undertake whole building improvements. Utilities and regulators should facilitate the sharing of whole building data (including billing data) with regional analysts, recognizing security and privacy concerns. These data will be useful in identifying savings potential from emerging technologies, new uses of electricity that contribute to load growth and standby or "idle mode" energy use. Utility program portfolios should incorporate programs that rely on a whole building approach to savings. A report on data analysis approaches and availability barriers should be completed by the end of 2017.

REG-10 **Develop strategies to coordinate energy-efficiency planning within region.** [NEEA, Bonneville, Energy Trust of Oregon, Utilities] Regional entities working together can more cost-efficiently capture conservation for many measures that have broad regional application and require coordination among implementing parties. NEEA recently facilitated the development of an initial regional strategy for commercial and industrial lighting, one of the largest sources of new efficiency potential in a very fast-changing market with a complex delivery infrastructure that crosses all utility boundaries. Similar facilitation efforts should be developed for other areas where regional cooperation among utilities, Bonneville, states, trade allies, and others is valuable. NEEA should initiate at least three such regional strategy efforts by the end of 2016.

Regional Actions Supporting Plan Implementation – Model Conservation Standards

The Council recommends that the region pursue the following actions to implement the Seventh Plan's Model Conservation Standards:

MCS-1 **Ensure all-cost effective measures are acquired.** [Bonneville, Utilities, Energy Trust of Oregon, States]

The following text is under discussion by Council separately

In order to achieve all cost-effective conservation, all customer segments should participate in programs. The Northwest Power Act has required that the Bonneville Power Administration (BPA) distribute the benefits of its resource programs "equitably throughout the region."[1] Bonneville and the regional utilities should determine how to improve participation in cost-effective programs from any underserved segments. Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: moderate income customers, customers in rural regions, small businesses owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers. Ideally, the customers in the HTR segment should participate in similar proportion to non-HTR customers, assuming similar savings potential.

To accomplish this goal, Bonneville and the utilities in their overall data collection should include, to the extent ~~possible~~ **its readily available,** demographic and business

[1] Northwest Power Act §6(k), 94 Stat. 2722

characteristic data that helps identify the existence of any HTR segments. Bonneville and the utilities should also coordinate with local and state agencies to leverage available data on various HTR segments. For example, community action programs will have information on low-income customers and program participation. The portion of participating customers in the assumed HTR segments should then be compared against the portion of customers within these segments in the utility's service area. This will determine which customer segments are indeed underserved. There may be other approaches to determining the HTR segments. For example, utilities may be able to review federal census track data against program participation. Bonneville and the utilities should report to the Council on the proportion of participation from HTR segments and how these data were collected. The report should occur in 2017, and then annually thereafter. **The strategies to improve participation by HTR segements should be considered in BPA's overall assessment and possible redesign of energy efficiency implementation as described in BPA-6.**

After the first report, and prior to the completion of the Council's mid-term assessment, Bonneville and the utilities should devise strategies to improve participation by customers in cost-effective conservation in any underserved HTR segments identified in the report.
Evaluating all HTR sectors is important. In evaluating the sub-sectors highlighted below, considerations should include **where data is readily available:**

- Small and Rural Utilities: One specific segment that has been shown to have special difficulties in implementing energy-efficiency programs is the small and rural utility segment. A study conducted by the RTF in 2012 identified technical support needed by these utilities and infrastructure delivery constraints.[2] A series of initiatives have been put in place to remedy some of the problems identified in that report and improve participation, but issues may remain that the assessment should investigate. For example, some utility customers of Bonneville may have limited staff and limited access to contractors to effectively use their Bonneville energy efficiency incentive. Strategies to improve participation should consider arrangements among utilities to share efficiency planning and implementation activities. Product availability and measure uptake may lag in smaller rural markets compared to larger markets. NEEA market transformation initiatives focused on those lagging markets should be considered as possible solutions along with assistance from Bonneville on education, program administration and measures directly tailored toward the small and rural utilities.

[2] Small and Rural Utility RTF Technical Support Needs Study.
http://rtf.nwcouncil.org/subcommittees/smallutilities/RTF%20Small_Rural_01-19-12_FINAL.pdf

- Low-Income Households: Existing programs, such as the U.S. Department of Energy Low-Income Home Energy Assistance Program, have provided an infrastructure to increase penetration of energy-efficiency measures into the low-income segment. However, it is not known whether these programs and their current structure are sufficient. The assessment should determine whether the pace of low-income conservation improvements achieved, over the last five years, is sufficient to complete implementation of nearly all remaining cost-effective potential in the low-income segment by 2035. Strategies to improve participation and pace of acquisition should consider further coordination between utility, tribal, and Community Action Programs (CAP) identified by Bonneville's Low-Income Work Group. That work group should continue to seek improvements in program coordination and implementation as a joint effort between utilities, tribes, states and CAP agencies.

- Moderate-Income Households: The up-front cost required to purchase or install efficiency measures is often a significant barrier to moderate-income customers. Financial incentives from utilities, Bonneville, and Energy Trust of Oregon usually only cover a portion of measure cost, thus potentially limiting the participation of these customers, who do not qualify for the high incentives offered in programs for low-income households. The assessment should investigate program participation rates among households above the low-income threshold and below median income levels and the reasons for any discrepancy relative to higher income households. The Energy Trust of Oregon has a well established program called Saving Within Reach that could provide helpful guidance on the potential establishment and operation of a moderate income program should a program be needed region-wide.

- Manufactured Homes: The manufactured home segment may face special challenges related to income, ownership, building codes, and some difficult-to-implement conservation measures specific to manufactured housing and their heating systems. The assessment should determine whether the adoption of measures in the manufactured home segment is on pace to complete implementation of nearly all remaining cost-effective potential over the next 20 years. Where expected shortfalls appear, specific barriers to implementation should be identified and solutions targeted at those barriers. While this market segment has been successfully targeted with a limited set of conservation measures (e.g. duct sealing), a more comprehensive approach that identifies and implements an entire suite of cost-effective measures during a single visit may be more cost-efficient.

MCS-2 **Develop program to assess and capture distribution efficiency savings.** [RTF, <u>Bonneville</u>, <u>Utilities</u>] Significant cost-effective savings can be achieved through voltage optimization measures, such as conservation voltage regulation. The relatively slow historical adoption of these measures has been due to a variety of barriers that may be addressed by programs or performance standards. By spring of 2017, Bonneville should develop a plan to determine potential savings identify barriers, and develop program assistance or distribution system performance standards. The plan should outline resource needs sufficient to assess potential and begin programs for one-third of its utility customers and customer load by 2021 with the goal of implementing all cost-effective measures for 85 percent of its utility-customer load by 2035. Investor-owned utilities should do similar assessments and implement cost-effective efficiency improvements by 2035.

MCS-3 **Encourage utilities to actively participate in the processes to establish and improve the implementation of state efficiency codes and federal efficiency standards.** [State Regulators, Bonneville, Utilities] Without robust efficiency programs paving the way for new measures and practices, efficient building codes and standards could not achieve their current levels of efficiency. However, for codes to continue to improve, programs need flexibility in pursuing measures that may not currently be cost-effective, but demonstrate likely cost reductions. In addition, as building codes and federal standards begin to push the envelope of emerging efficiency practices, regulators should provide allowance for programs to offer measures and practices which are new, have limited market acceptance or availability, or are part of voluntary code provisions. Based on results of code compliance studies, Bonneville and the utilities should work with authorities having jurisdiction to encourage code compliance in any areas where it is lacking. This activity should be ongoing throughout the action plan period and should be reviewed after each new code adoption.

MCS-4 **Develop a regional work plan to provide adequate focus on emerging technologies to help ensure adoption.** [Bonneville, NEEA, Utilities, National Labs, Energy Trust of Oregon, Council] Nearly half of the potential energy savings identified in the Council's Seventh Power Plan are from emerging technologies or measures not in previous plans. The region has proven success at moving emerging technologies and design strategies into the marketplace and should continue to work toward this goal. This includes (1) tracking adoption of new measures in the Seventh Plan supply curves, (2) identifying actions to advance promising technologies and design strategies, (3) increasing adoption of existing technologies with low market shares, and (4) scanning for new technologies and practices. The Regional Emerging Technology Advisory Committee (RETAC) should develop a work plan to ensure success in these four areas and to track progress over the action plan period. The initial work plan should be developed by mid-2016 and updated every two years.

MCS-5 **Actively engage in federal and state standard development.** [Council, Bonneville, NEEA, Energy Trust of Oregon, Utilities] Regional presence in the standard setting process has provided immense value to the region and the country. NEEA, on behalf of the region's utilities, should lead the effort to continue and perhaps expand this engagement with the U.S. Department of Energy as well as provide data and recommendations. The Council should continue to represent the Northwest states' interest in these processes. The region's engagement should inform the standards and the test procedures. NEEA should also assist the states in the development of state-level standards for products not covered by the federal rules. This should be an ongoing activity with periodic assessment of resource requirements.

MCS-6 **Develop and deploy best-practice guides for the design and operations of emerging industries.** [NEEA, Bonneville, Utilities, Trade Allies, States] Emerging industries such as indoor agriculture and large data centers are rapidly increasing throughout the region. Many of these facilities have significant load that could be reduced with guidance on best-practice design and operational approaches. Development of the first generation of best-practice guides should be available by late-2016. NEEA should identify opportunities to deploy the best-practice guides to decision makers and design and operations professionals in the respective industries.

MCS-7 **Monitor and track code compliance in new buildings.** [NEEA, State code agencies, National Labs] Ensure new residential and commercial buildings are built at or above code-required levels across the four Northwest states. NEEA should work with regional code stakeholders to develop and implement appropriate methods to directly measure levels of code compliance and associated energy savings. The compliance study should assess local jurisdiction code plan review and inspection practices. Site visits with local code jurisdictions, and the design and construction industry should be conducted to assess training, education, and other resource needs to assure high levels of code compliance. NEEA should explore whether there may be other regional entities (e.g. Pacific Northwest National Laboratory) with whom NEEA could collaborate and leverage its work. NEEA's work plan and budget should include sufficient resources for continuing compliance studies with the expectation of reports for all states and sectors by 2020. Ideally, the completion of these reports should be timed to inform future code updates.

Bonneville Actions Supporting Plan Implementation

The Council recommends that Bonneville pursue the following actions to maintain consistency with the Seventh Plan:

BPA-1 **Achieve Bonneville's share of the regional goal for cost-effective conservation resource acquisition.** [Bonneville] Bonneville should continue to meet its share of the Seventh Plan conservation goals working with its public utility customers, the Northwest Energy Efficiency Alliance, the Regional Technical Forum, the states, and the tribes. Bonneville should ensure that public utilities have the incentives, support, and flexibility to pursue sustained conservation acquisitions appropriate to their service areas in a cooperative manner, as set forth in detail in the conservation action plan items. Bonneville should offer flexible and workable programs to assist utilities in meeting the conservation goals, including a backstop role for Bonneville should utility programs fail to achieve these goals **(See Action Item RES-1 for specifics)**

BPA-2 **Update methods to identify least-cost resources needed to maintain regional adequacy. (See Action Item RES-3 for specifics)** [Bonneville]

BPA-3 **Continue efforts to establish demand response.** [Bonneville] Bonneville should continue its efforts to evaluate and enable the use of demand response as a resource to meet future resource needs. This effort should identify and remove barriers to successful implementation of demand response and include:

- Establishing resource acquisition rules for demand response as an integrated part of assessing resource needs as detailed in RES-3
- Expanding the infrastructure for demand response as detailed in RES-4
- Identifying the amount and cost of demand response potential including potential in the Bonneville customer utilities service areas that could be made available for Bonneville resource needs
- Assessing barriers to the further development of demand response by Bonneville and implementing actions to overcome those barriers

Bonneville should include the resource acquisition rules, the potential assessment for demand response and the assessment of barriers to developing demand response in its Resource Program.

BPA-4 **Improve access to demand response data.** [Bonneville] Bonneville should create systems to add demand response dispatch data to its existing publicly available data on the Bonneville public website. **(See Action Item REG-2 for specifics)**

BPA-5 **Quantify the value of conservation in financial analysis and, budget-setting forums.** [Bonneville] Bonneville should estimate both the cost and benefit (value) of its historic and forecast investments in energy efficiency with respect to its overall net revenue requirement for both power supply and transmission services. Data on both the costs and benefits should be publicly available in forums where agency budgets and investment allocation are discussed and decisions are made. The value of conservation is often missing from discussions setting budgets for conservation while the cost elements are always present. By quantifying the financial value of cost-effective conservation and the revenue requirement compared to no conservation, there would likely be greater buy-in from utility customers for the efficiency expenditures. Bonneville should work with the Council to develop a method to calculate estimated value of conservation (e.g., return on investment) and provide the estimate as part of its budgeting processes, Integrated Program Review, Capital Investment Review, and annual budget documents. Bonneville should have robust data to make this estimate before its next Integrated Program Review.

BPA-6 **Assess Bonneville's current energy efficiency implementation model and compare to other program implementation approaches.** [Bonneville] Bonneville's current efficiency program approach is based on a proportional funding model. Program offerings and incentives are designed to provide equal access to measures and program funding in proportion to Tier 1 load. This model, while effective in achieving funding equity among customer utilities, may limit the ability of Bonneville to focus its acquisition efforts on acquiring all cost-effective conservation in the region.

By the end of 2017, Bonneville should commission a study to assess alternative program design, funding allocation and incentive mechanisms and compare benefits and costs of implementing alternative models. Bonneville should develop the scope of the study in consultation with the Council and stakeholders. Alternative program approaches could include a focus on the value of the savings based on winter capacity needs, geographical needs, or localized capacity constraints. Additional approaches should explore different cost performance metrics such as lowest first year cost, lowest levelized cost, or highest benefit-to-cost ratio. The study should develop an example portfolio for each approach, assessing the resulting potential savings and costs to Bonneville and its customers. The study should, for each portfolio:

- Assess likelihood of achieving all cost-effective conservation;
- Address the technical, policy, and economic tradeoffs;
- Assess the incentives and disincentives to program participation;
- Assess administrative process efficiency;
- Assess changes in the value of cost-effective energy efficiency, revenue requirements and how the benefits flow to customers (see BPA-5);
- Assess effectiveness of achieving savings for large projects at end-use customers;
- Assess effectiveness of the bi-lateral transfer mechanisms in allowing utilities to exchange energy-efficiency funding to balance utility circumstances of power needs and conservation potential.

BPA-7 **Bonneville should perform an analysis of its operating reserve requirements.** [Bonneville] Bonneville should conduct an analysis of the most cost-effective method of providing operating reserves that meet system reliability requirements at the lowest probable cost. Bonneville should report the input assumptions, methods of analysis and results of this analysis to the Council for use in the Council's planning process. The analysis should be included in each Bonneville Resource Program. (See Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706.)

BPA-8 **Bonneville should continue to evaluate methods for reducing or mitigating regional generation oversupply conditions.** [Bonneville] Bonneville should work with its customers to create incentives that help mitigate generation oversupply conditions.

BPA-9 **Bonneville and the Council should develop a report that identifies barriers to conservation acquisition by Bonneville's customer utilities with recommended strategies to eliminate or minimize such barriers. [Bonneville, Council]** The report should identify economic, contractual, motivational, institutional, and political barriers to acquisition and implementation of conservation and demand response measures. Strategies to address barriers should be developed in consultation with customer utilities and other stakeholders. The report should be completed by the end of 2017.

BPA-10 **Enhancing BPA end-use load forecasting**. [Bonneville, Council] Council staff will work closely with Bonneville staff to implement the Council's long-term end-use forecasting model. The enhancement in end-use modeling capability will enable BPA to better reflect impacts of future codes and standards and assist BPA conservation plans to more explicitly account for impact of conservation acquisitions on forecast loads.

Council Actions Supporting Plan Implementation

COUN-1 **Form Demand Response Advisory Committee. [Council]** A major finding of the Seventh Plan is that the region would benefit from the development of demand response (DR) resources. To facilitate this, the Council should establish a Demand Response Advisory Committee to assist in the identification of strategies to overcome regional barriers to DR implementation and the quantification of DR potential. The scope of this committee's activities should be to facilitate the deployment of demand response resources in the region by serving as a forum for sharing program experience and data. This committee should be chartered by the Council by the end of FY2016.

COUN-2 **Continue to co-host the Pacific Northwest Demand Response Project (PNDRP).** [Council] The Council should continue to coordinate with the Regulatory Assistance Project to host the Pacific Northwest Demand Response Project (PNDRP). PNDRP should be convened at least annually.

COUN-3 **Review the regional resource adequacy standard.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current adequacy metric (loss of load probability) and threshold (maximum value of 5%) has been used since 2011 as a good indicator of potential future power supply limitations. However, the loss of load probability metric may not be the most appropriate for determining the adequacy reserve margin and the associated system capacity contribution for specific resources (see COUN-4 and COUN-5), both of which are critical components of the Regional Portfolio Model. The loss of load probability metric (as currently defined) is also not appropriate for estimating the effective load carrying capability of resources. The Council should review and, if necessary, amend its standard. Any change to the adequacy standard should be adopted by the Council in time to be used for the development of its next power plan.

COUN-4 **Review the Resource Adequacy Assessment Advisory Committee assumptions regarding availability of imports.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current assumptions regarding the availability of imports from out-of-region sources and from in-region market resources should be reexamined. The sensitivity of total system cost to import availability has been demonstrated in the Regional Portfolio Model analysis. To minimize cost and avoid the risk of overbuilding, the maximum amount of reliable import should be considered. The Resource Adequacy Advisory Committee should reexamine all potential sources of imported energy and capacity and make its recommendations to the Council. Any changes to import assumptions should be agreed upon in time to be used for the development of the next power plan.

COUN-5 **Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to the adequacy reserve margin (ARM), calculated using output from the Council's adequacy model (GENESYS). The ARM is effectively a minimum build requirement that ensures that resource strategies selected by the Regional Portfolio Model will produce acceptably adequate power supplies. The underlying methodology and assumptions used to assess ARM values should be thoroughly reviewed by regional entities. Any changes to the ARM methodology should be agreed upon prior to the development of the next power plan.

COUN-6 **Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to resource associated system capacity contribution values (ASCC), which are calculated using the Council's adequacy model (GENESYS). The ASCC provides the effective capacity value of resources when they are incorporated into a power supply with storage (e.g. the Northwest hydroelectric system). The methodology and assumptions used to assess ASCC values should be thoroughly reviewed by regional entities. Any changes to the ASCC methodology should be agreed upon prior to the development of the next power plan.

COUN-7 **Perform a regional analysis of operating reserve requirements. [Council]** The Council will use the Bonneville analysis of reserve requirements (See action item BPA-7) and work with other regional stakeholders to complete a regional analysis of the most cost-effective method of providing operating reserves that meet reliability requirements at the lowest probable cost. This analysis should be completed in time to include in the next power plan.

COUN-8 **Participate in and track WECC activities. [Council]** The Council should continue to represent the Northwest region in the planning activities at the Western Electric Coordinating Council (WECC), including participation on the Loads and Resources Subcommittee (LRS). The LRS develops WECC resource adequacy guidelines and assessments and acts as the interface with NERC in these areas and on NERC's development of standards in the resource adequacy area. The WECC and NERC activities provide the background within which the Council analyzes adequacy issues and approaches and develops its regional adequacy assessments.

COUN-9 **Monitor regional markets and marketing tools that impact the dispatch of the power system.** [Council] Since the Sixth Plan, the region has seen the advent of an energy imbalance market between PacifiCorp and the California ISO. There have also been efforts underway at the Northwest Power Pool to create products and services that improve the dispatch of the power system for balancing load and generation. Both of these efforts have resource implications for the region. The Council should monitor these efforts and any additional efforts that impact dispatch to assess whether its power system modeling should be altered.

COUN-10 **Reaffirm and update Section 6(c) policy.** [Council and Bonneville] The Council and Bonneville worked together in the 1980s to establish a policy on how to implement Section 6(c) of the Northwest Power Act, the provision specifying how Bonneville is to assess and decide whether to add a “major resource” to its system. The Section 6(c) policy includes a provision that requires Bonneville periodically to review and (if necessary) update the policy, with the help of the Council. Bonneville and the Council and Bonneville last reviewed and updated the policy in 1993, and have mutually agreed to defer review ever since. The Council and Bonneville should review, reaffirm or update the Section 6(c) policy within the next two years.

COUN-11 **Participate in efforts to update and model climate change data.** [Council, River Management Joint Operating Committee, System Analysis Advisory Committee, Resource Adequacy Advisory Committee] The Council should continue to work with regional entities that collect and process results from global climate analyses. This includes monitoring efforts overseen by the RMJOC to downscale global results for use in the Northwest. Information that is critical for use in Council planning models includes climate modified unregulated flows, their associated rule curves and projected monthly temperature changes. The Council will also continue to explore ways to incorporate climate induced impacts to hydroelectric generation and load into its Regional Portfolio Model. Results from the most recent Intergovernmental Panel on Climate Change Assessment Report are currently being downscaled for the Northwest but that work is not expected to be completed until early 2017. The results of that effort should be thoroughly vetted prior to the development of the next power plan.

MAINTAINING AND ENHANCING COUNCIL’S ANALYTICAL CAPABILITY

The Council’s power plan is extremely data and model intensive. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. It is one that the Council’s staff cannot do alone. Data collection for the regional power system and alternative resources available to meet demand is something best accomplished through regional cooperation. The action plan contains recommendations to maintain and improve planning data for the region.

Load Forecasting

ANLYS-1 **Improve industrial sales data**. [Council, NEEA, Utilities] The Council will work with BPA, NEEA, and utilities to improve industrial sector sales data by disaggregating those data by NAICS codes to improve forecasting and estimates of conservation potential. Currently, industrial sales are reported by utilities to FERC and EIA in an aggregate fashion. Reporting sales data at a more disaggregated, industry specific (e.g. lumber and wood products, food processing) level would improve the ability to forecast loads and conduct assessments of conservation potential. The Council in cooperation with

Bonneville should develop a system to regularly collect and categorize data accounting for at least 80% of industrial loads. Confidentiality issues should be addressed and solved. This process and improved industrial data sets should be completed by 2018.

ANLYS-2 **Improve long-term load forecast for emerging markets**. [Council, Demand Forecasting Advisory Committee] The Council should enhance the Council's long-term end-use forecasting model's capability to account for rooftop solar PV with electricity storage, Data Centers (large, small and embedded data centers), and indoor agricultural (cannabis) loads. The Council will work with utilities and advisory committee members to monitor and forecast loads for these fast growing markets.

ANLYS-3 **Explore development of an end-use conservation model.** [Council] Many conservation planners in the industry utilize an integrated end-use based conservation assessment model to closely tie savings to load forecasts. In addition, models may also be improved by including performance-based efficiency approaches. The Council will scope the development of a working model. Depending on findings/budget, the Council may contract out model development. Report on scope will be completed by 2017.

ANLYS-4 **Review and enhancement of peak load forecasting.** [Council, Demand Forecasting Advisory Committee, Resource Adequacy Advisory Committee] This task reviews and reconciles peak load forecasting methods used for long-term resource planning (RPM) and short-term Adequacy Assessment (Genesys) analysis. This task should be completed before the next Resource Adequacy Assessment.

Conservation

ANLYS-5 **Establish a forum to share research activities and identify and fill research gaps.** [Council, RTF, NEEA, Utilities, Energy Trust of Oregon, Bonneville] There are a variety of ad hoc conservation-related research initiatives ongoing in the region. Among these activities are research on reliability of energy and capacity savings, emerging technologies, end-use load shapes, regional stock assessments, product and equipment sales data, and non-energy impacts of efficiency measures. However, these activities lack the coordination that could improve usefulness, reduce duplication, provide better access to existing data, and identify significant research gaps. The Council should facilitate a research coordination forum to define research needs, identify key players and a coordinating body, identify gaps, and develop plans to prioritize gap filling. The forum should develop a roadmap and a work plan to identify tasks and implementers considering the existing research initiatives currently underway. The roadmap and work plan should be completed by mid-2018.

ANLYS-6 **Prioritize research and adoption of energy-efficiency measures that also save water.** [Council, RTF, Bonneville, Utilities, Energy Trust of Oregon, NEEA] In recognition of the non-energy benefits of saving water, utilities should prioritize adoption of cost-effective measures that also conserve water. Several such measures identified in the Seventh Plan (showerheads, water supply facilities improvements, irrigation improvements) save water in addition to energy. Consideration of water conservation benefits in addition to energy-savings benefits should increase the likelihood of measure adoption. In addition, the last comprehensive study of water/wastewater was completed over ten years ago and should be updated. This action item calls for: tracking and reporting of water savings in addition to energy savings, conducting research to better understand savings opportunities for water-processing industries (water supply and wastewater), evaluation of water-saving measures, and raising awareness of other water-saving measures. A new or updated analysis of water/wastewater baseline should be completed by 2018.

ANLYS-7 **Reporting should include explicit information on what baseline is assumed.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, RTF] As part of its annual Regional Conservation Progress (RCP) report, the RTF provides the Council an estimate of energy savings toward the current plan's conservation goals. To accurately determine this, the RTF and Council need to understand what baseline was assumed for the energy-efficiency measures. The progress against the plan's goals should be measured against the plan's baselines. If the baseline is not aligned with the plan, the RTF can (generally) adjust the savings accordingly as long as measure and baseline information are included in the utility's tracking system. Bonneville currently endeavors to make these adjustments through its momentum savings analysis. The RTF should provide a progress report by the end of 2018 with the goal that all savings provided for the RCP report include baseline information by 2020.

ANLYS-8 **Identify and analyze significant non-energy impacts.** [RTF, States] Although difficult to quantify, non-energy impacts (both benefits and costs) due to efficiency improvements (such as water savings and health benefits due to reduction in wood smoke emissions[3]) may be significant and thus justify societal investment, regardless of whether the measures are cost-effective on an energy benefits and costs alone. The region should conduct research to identify and quantify such non-energy impacts. The Regional Technical Forum in cooperation with the RTF Policy Advisory Committee should identify and provide information to prioritize research on non-energy impacts taking into consideration the resources needed to sufficiently quantify impacts and the potential impact of quantification on measure cost-effectiveness. States should consider such benefits when setting cost-effectiveness limits for measures and programs recognizing that it may not be appropriate for the utility system to pay for non-energy benefits that do accrue to the power system. Specifically related to health benefits from wood smoke reduction, the RTF should include model language on residential space heating measures for which significant secondary health benefits exist, as these measures are updated. As other significant non-energy benefits are identified with substantiated research, the RTF should either quantify or include model language to note their impact.

[3] See Chapters 12 and 19 for more information

ANLYS-9 Include reliability of capacity savings estimates in RTF guidelines. [RTF] The RTF should update its guidelines to include savings reliability requirements for capacity, similar to how it currently treats energy savings estimates. In doing so, the RTF will review the unit energy savings measures to determine whether existing load shapes meet those requirements and identify any research needs to improve reliability of capacity estimates. The RTF should develop recommendation memos that address each measure and identify research needs for all measures by the end of 2017.

Generation

ANLYS-10 Planning coordination and information outreach. [Council] The Council will continue to participate in the development of Bonneville's Resource Program and in utility integrated resource planning efforts. In addition, the Council will periodically convene its planning advisory committees for purposes of sharing information, tools, and approaches to resource planning.

ANLYS-11 Re-develop the revenue requirements finance model – MicroFin. [Council, Bonneville, User Group] The Council , in coordination with Bonneville and a user group convened from interested parties of the Generating Resources Advisory Committee, should review and redevelop the revenue requirements finance model MicroFin, with a completed model in place by the Seventh Plan Mid-Term Assessment. The Council should develop a work plan to review the current version of MicroFin, identify technology needs in order to upgrade the model, and either perform the redevelopment in-house or outsource it via a request for proposals. The redevelopment should be completed by the Seventh Plan Mid-Term Assessment in order to have time to prepare the model for use in the development of the Eighth Plan. The Council should convene a user's group to help ensure the new model is user friendly and to help inspect the results.

MicroFin is the Council's primary financial tool for developing levelized costs and RPM inputs for new generating resources and it is in need of redevelopment. The model produces accurate and useful results, however it is based on a legacy system that no longer fits the current Excel environment and is cumbersome to work with. An upgrade will allow for easier enhancements to be made to the model and an improved user interface. The new model will ideally be accompanied by a user's guide that will ensure that it is easier to use as well as to share with the public.

ANLYS-12 Update generating resource datasets and models. [Council] The Council should review its various generating resources datasets, looking for opportunities to consolidate and streamline the data update process. This review and possible upgrade to a single system or dataset should be ongoing after the Seventh Plan, with completion in time for the Eighth Plan. The Council maintains and updates multiple sets of data on regional generating resources and projects, including:

- Project database – tracks existing and new projects in the region and their development and operating characteristics, generation data, technology and specifications, and various other data
- Renewable Portfolio Standard (RPS) Workbook – tracks generating projects and state RPS within WECC (with a focus on the Pacific Northwest) and forecasts future resource needs
- AURORA resource database
- GENESYS dataset

These datasets are important sources of information for many of the Council's models and analyses. While currently maintained separately, they share much of the same information and there is an opportunity to streamline both the updating of data and the data sharing. The value in a consolidated data source would be to ensure that all of the models are using the exact same data and values and it would also reduce staff time spent updating and maintaining multiple datasets.

ANLYS-13 Monitor and track progress on the emerging technologies that hold potential in the future Pacific Northwest power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor on an ongoing basis the emerging technologies identified in the Seventh Plan as potential resources of the future regional power system. There are several emerging technologies which could play an important role in the operation of the future power system, including:

- Distributed power with and without storage (Solar PV, CHP)
- Utility Scale Solar PV with battery storage
- Enhanced geothermal systems (EGS)
- Offshore wind
- Wave and tidal energy
- Small modular reactors (SMR)
- Energy Storage
    - Pumped storage with variable speed technology[4]
    - Battery storage
    - Other

The Council should track significant milestones in development, cost and technology trends, lifecycles, potential assessments, and early demonstration and commercial projects. Included in the analysis of the technologies is identifying any potential benefit the resource might provide during low water years. By monitoring these resources

[4] While pumped storage itself is not an emerging technology, its potential uses and benefits are changing and emerging to fit new generation challenges. It should be monitored along with the emerging technologies and assessed as a resource in the future power system.

closely in between power plans, the Council will be prepared to analyze them and determine if they are viable resource alternatives in the Eighth Plan.

ANLYS-14 Scope and identify ocean energy technologies and potential in the region, determine cost-effectiveness, and develop a road map with specific actionable items the region could collaborate on should development be pursued. [Council, Generating Resource Advisory Committee] The Council should convene a subgroup of the Generating Resources Advisory Committee that includes regional utilities and other ocean energy stakeholders to a) scope out the emerging ocean energy technologies and identify the cost and realistic potential in the region, b) develop a set of regional priorities and action items needed should ocean energy development be pursued, and c) foster better coordination of utility efforts and investments in ocean energy.

There are several ocean energy technologies that have significant technical potential in the Pacific Northwest, including wave energy, off-shore wind, and tidal. These technologies are still emerging and in various stages of the research and development phase. While there have been efforts within the region to pursue the research and development of ocean energy, they have been relatively isolated and have not resulted in investments and projects to-date. The Council can help to foster better coordination of utility efforts across the utility community in collaboration with developers and other stakeholders to determine if there is regional interest in the development of ocean energy and outline steps to explore it further.

ANLYS-15 Research and develop a white paper on the value of energy storage to the future power system. [Council, Generating Resources Advisory Committee] The Council should convene a subgroup of subject matter experts from its Generating Resources Advisory Committee to assist in the research and development of a Council white paper on the full value stream of energy storage and its role in the power system, including transmission, distribution, and generation. In addition, the white paper should investigate the existing need for frequency and voltage regulation and balancing reserves in the regional power system. The Council should author the white paper with help from industry experts, or lead a request for proposals and select a consultant to write the paper. The white paper should be completed in advance of the Eighth Plan.

One of the potential constraints to extensive storage development is the ability of the developer and/or investor to capture and aggregate the full value of the storage system's services in a non-organized market and transform interest and overall system need into revenue streams and project funding. Many of the benefits of large scale storage are the portfolio effects for an optimized regional system, not just solely to a specific power purchaser, utility or end-user, and therefore it can be difficult to raise funds and seek cost-recovery for storage projects if the purchaser is not directly benefiting from all of the services, or is paying for a service that benefits others who are not also contributing funds. The white paper should clearly identify the issues and barriers and provide useful information that would be beneficial to the region's decision makers, power planning entities and integrated resource planning processes.

ANLYS-16 Track utility scale solar photovoltaic costs, performance and technology trends in the Pacific Northwest, and update cost estimates. [Council, GRAC] The Council should continue to monitor on an ongoing basis the costs and performance and technology trends of solar PV in the Pacific Northwest and update the forecast of future cost estimates as necessary. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Solar PV is a rapidly evolving technology, both in terms of cost and performance. The Seventh Plan required development of a forecast of future solar PV costs. With continued uncertainty over solar installation costs and performance, updates to estimated installation costs and forecasts are required to accurately reflect the real world market. Utility scale solar installations paired with large battery systems could add further value to solar and is another important trend to follow. Detailed production estimates for many locations across the Northwest would also be useful.

ANLYS-17 Track natural gas-fired technology costs and performance, and update as necessary, particularly around combined cycle combustion turbine (CCCT) and reciprocating engine technologies. [Council, Generating Resources Advisory Committee] The Council should continue to monitor natural gas-fired technology costs and performance and technology trends in the Pacific Northwest, specifically concerning CCCTs and reciprocating engines. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Natural gas-fired generation, particularly CCCT and reciprocating engine technologies, continue to evolve in terms of cost and performance and may play an important role in the future power system.

ANLYS-18 Monitor new natural gas developments in the region and gauge the potential impact on the regional power system. [Council, Generating Resources Advisory Committee, Pacific Northwest Utilities Conference Committee] The Council should monitor and track on an ongoing basis new natural gas developments in the region (such as pipelines, storage, LNG export terminals) and determine the potential future impacts on the regional power system. PNUCC is following similar issues, which may offer an opportunity for collaboration.

New natural gas uses and system development in the region may impact future power generation. On-going issues to track and potentially analyze include:

- Potential pipeline constraints, particularly on the west-side
- LNG facility developments in Canada and the West Coast of the U.S.
- Shale production from Canada and the U.S. Rockies
- Methanol plant development
- Natural Gas Vehicle (NGV) transportation

- Track on-going research on methane emissions resulting from gas production and transportation, and potential policy impacts

ANLYS-19 Monitor current and proposed federal and state regulations regarding the impacts of generating resources on the environment in the Pacific Northwest and subsequent impacts to the regional power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor and track on an ongoing basis the current and proposed regulations regarding the environmental impacts of generating resources and the subsequent impacts on the regional power system in terms of cost and operation.

System Analysis

ANLYS-20 Review analytical methods. [Council, Bonneville] As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the power plan. The goal of this review is to improve the Council's ability to analyze major changes in regional and Bonneville systems and make recommendations to ensure a low-cost, low-risk power system for the region. This review will focus on changing regional power system conditions such as capacity constraints, integrating intermittent resources, and transmission limitations to better address these issues in future power plans.

ANLYS-21 GENESYS Model Redevelopment. [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The GENESYS model has been used extensively by the Council, Bonneville and others to assess resource adequacy. It contains, as one of its modules, Bonneville's hydro regulation model (HYDROSIM). GENESYS has also been used to assess costs and impacts of alternative hydroelectric system operations (e.g. for fish and wildlife protection). It can be used to assess the effective load carrying capability of resources (e.g. wind and solar) and it can provide estimates of the impacts of potential climate change scenarios. The model, however, has components and file structures that are decades old. Because of the multiple uses of GENESYS and because it is a critical part of the Council's process to develop the power plan, it should be redeveloped to bring the software code up to current standards, to improve its data management and to add an intuitive graphical user interface (GUI). The use of an outside contractor is likely the best course of action but options will be reviewed by the Council, Bonneville and the System Analysis and Resource Adequacy Advisory Committees. Recommendations will be made to the Councilto decide on an appropriate approach given the funding available. This redevelopment should be completed in time for the next power plan.

ANLYS-22 Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations. [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's GENESYS model simulates the operation of the hydroelectric system plant-by-plant for monthly time steps. For hourly time steps, however, it simulates hydroelectric dispatch in aggregate. To do that, an approximation method is used to assess the aggregate hydroelectric system's peaking capability. That method should be reviewed and enhanced to better simulate the hourly operation of the hydroelectric system. As a first step, the Resource Adequacy Advisory Committee should review real-time operations. In order to improve the simulation, it may be necessary to break up the aggregate hydroelectric system used for hourly simulations into two or three parts, reflecting the different conditions and operations on the Snake River and on the upper and lower Columbia River dams. This work may also require the use of an outside contractor. Any changes in the GENESYS model should be complete in time for the next power plan.

Transmission

ANLYS-23 Coordinate with regional transmission planners. [Council] ColumbiaGrid and Northern Tier Transmission Group (NTTG) both have regional responsibilities for transmission system planning. The Council will coordinate with these organizations to work towards consistent regional planning assumptions and track efforts that may have implications for the power plan.

ANLYS-24 Transmission Expansion Planning Policy Committee (TEPPC). [Council] One of the primary functions of TEPPC is to oversee and maintain public databases for transmission planning. The Council will work with this committee on coordinating the public data used in the Council's planning process with the data produced by this committee. To the extent possible the Council will use these data to inform assumptions for generation and load outside the region.

FISH AND WILDLIFE

F&W-1 Investigate further the effects of resource development, especially renewable resource development and associated transmission, on the environment in general and on wildlife in particular. [Council, State Fish and Wildlife Agencies, Indian Tribes, State Energy and Energy Siting Agencies, Transmission Providers, Utilities, Bonneville] The region's fish and wildlife agencies and Indian tribes have expressed significant concern about the cumulative impacts to wildlife and the environment from the development of the region's power system, other than the effects from hydroelectric projects themselves for which there is a robust protection and mitigation program. This concern increased in the wake of the recent spurt in development in the region of renewable and gas-fired generation and the associated transmission lines, and the possibility of further such development. What is not clear is whether the current mechanisms for analyzing and addressing these effects are indeed inadequate, and if so, what can or should be done about this situation. The Council should work with representatives of the state fish and wildlife agencies and Indian tribes along with the state energy and energy siting agencies, transmission providers, utilities, Bonneville, and others to gain a better understanding before the next power plan of the nature and extent of both the adverse effects and of the regulations and programs intended to address those effects. This includes investigating and assessing what is known already about the extent of the effects; what laws, regulations and programs exist to analyze, assess, and address these effects and the efficacy of these efforts; what actions have been required to protect and mitigate for the generating resource and transmission effects and the efficacy of those actions; what gaps exist, if any, in terms of unaddressed cumulative impacts to the environment and wildlife from resource and associated transmission development; and how well the Council is considering these effects and costs in its power plan resource analysis.