Northwest **Power** and
**Conservation** Council



September 9, 2015

## MEMORANDUM

**TO:** **Council members**

**FROM:** **Tom Eckman**

**SUBJECT:** **Discussion of Draft Resource Strategy and Action Plan**

## BACKGROUND:

Presenter: Tom Eckman and Power Division Staff

Summary: On the morning of September 16th, staff will review the Resource Strategy and Action Plan chapters of the Power Plan with the full Council.

This agenda item is intended for members to review any suggested changes or concerns for these chapters that are raised by the Power Committee the day before. It is also an opportunity to discuss any questions or proposed changes from the rest of the Council.

Relevance: Council members need to be satisfied that the draft plan accurately reflects the policy guidance on the resource strategy and action plan items they wish to include in the plan. This agenda item provides members with the opportunity gain that assurance.

Workplan: 1.B. Develop Seventh Power Plan and maintain analytical capability

Background: Staff recently submitted the Resource Strategy and Action Plan chapters for review via email. Please refer to the full Council Packet for the printed version of these chapters.

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# CHAPTER 3: RESOURCE STRATEGY

## Contents



## List of Tables and Figures

# 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 seven 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 or potentially expanded reliance on extra-regional markets, 3) satisfy existing renewable-energy portfolio standards, 4) slightly reduce the use of the existing coal plants beyond the already announced retirements 5) increase the use of existing natural gas fired generation 6) increase the utilization of regional resources to serve regional energy and capacity needs and 7) 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 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 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. The important message of the resource strategy is the nature and priority order of resource development.

## Summary

The resource strategy is summarized below in seven 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 last 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 region should 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:** 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. 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 exceeding the Council's resource adequacy without development of additional winter peaking resources.

**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 or cannot deploy the demand response resources and develop the level of energy efficiency resources called for in this plan, the need for 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. In these instances, the Seventh Plan's resource strategy relies on new natural gas-fired generation to provide energy, capacity, and ancillary services.

**Renewables:** Increasing the requirements of state renewable portfolio standards was not identified as necessary to develop the least cost resource strategy for the region nor to comply *at the regional level* with recently promulgated federal carbon dioxide emissions regulations. The Seventh 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. As a result, compliance with renewable portfolio standards is assumed to be achieved nearly equally by wind and solar PV systems. However, power production from wind and solar PV projects creates little dependable winter peak capacity and increases the need for within-hour balancing reserves. The Seventh 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. 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.

**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.

**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 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 develop resources if necessary to avoid 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 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 effected 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 emissions reduction policies. These included either the federal government's estimates of the societal damage cost of carbon emissions or the risk of future carbon regulation or pricing or specific "non-pricing" policies. Each of these scenarios assumed differing levels of carbon prices 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 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, 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 (Base and High), Carbon Risk, Increase Renewable Portfolio Standards to 35 Percent and Maximum Carbon Reduction with Current 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 emissions.

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

- **Existing Policy, No Carbon Risk** - 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 regulatory cost risk in the future. It helps identify the effect of carbon 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 – Base (SCC-Base)** 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. The According to the Working Group:

  *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).*

  Therefore, in theory, the cost and risk of the resource strategy that achieves CO2 reductions equivalent to the Social Cost of Carbon would offset the cost of damage. The "SCC-Base" scenario uses the "3 percent discount rate" estimated damage cost while the "SCC-High" uses the "$95^{th}$ percentile" estimate of damage cost," that is, costs that encompass 95 percent of the estimated range of damage costs.[1]

- **Carbon Risk** - The carbon-risk scenario is intended to explore what resources result in the lowest expected cost and risk given current policy plus the risk that additional carbon reduction policies will be implemented. Each of the 800 futures imposes a carbon 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 price being imposed and the level of that price both increase. By 2035, the average cost of carbon rises to $47 per metric ton across all futures.

  This scenario was initially designed to represent the current state of uncertainty about future carbon 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 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.

- **Increase Renewable Portfolio Standard to 35 Percent** - This scenario assumes that regional renewable portfolio standards (RPS) are increased to 35 percent in 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

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

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 emissions, it did not include future carbon 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 emissions.

- **Maximum Carbon Reduction with Current Technology** – This scenario was designed to explore the maximum carbon 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 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 Risk, Increased RPS, Social Cost of Carbon) for reducing carbon emissions.

- **Maximum Carbon Reduction with Emerging Technology –** This scenario considers the role of new technologies might play in achieving carbon reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario it was not modeled in the Council's Regional Portfolio Model. Rather, the results of the **Maximum Carbon Reduction with Current Technology** scenario were used to define the role (e.g., capacity and energy requirements) new technologies would need to play in order to achieve further carbon reductions.

- **Resource Uncertainty** - Four scenarios explored resource uncertainties and carbon regulatory compliance cost and risk. Two examined the effect of the loss of a major non-greenhouse gas-emitting on the region's ability reduce power system carbon emissions. The **Unplanned Major Resource Loss** scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpected 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 emissions limits they assumed the cost future carbon regulatory risk used in the Carbon Risk scenario.

  Two additional scenarios tested the benefits or cost of 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 risk of compliance with federal carbon emissions limits, they assumed the cost future carbon regulatory risk used in the Carbon 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 Policies, No Carbon Risk scenario and with the future carbon regulatory cost assumed in the Carbon 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 Policies, No Carbon Risk scenario and with the future carbon regulatory cost assumed in the Carbon Risk scenario.

- **Increased Reliance on External Markets -** This scenario explored the potential benefits and risk of increased reliance 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 Policies, No Carbon Risk scenario.

- **Lower Conservation, No Carbon Risk –** 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 Policies, No Carbon Risk scenario, so no carbon regulatory cost risk or damage costs were assumed.

Results of these studies are compared in the discussion of the seven 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 emissions, rate and bill impacts and Regional Portfolio Model appears in Chapter 15 and Appendix L.

# THE RESOURCE STRATEGY

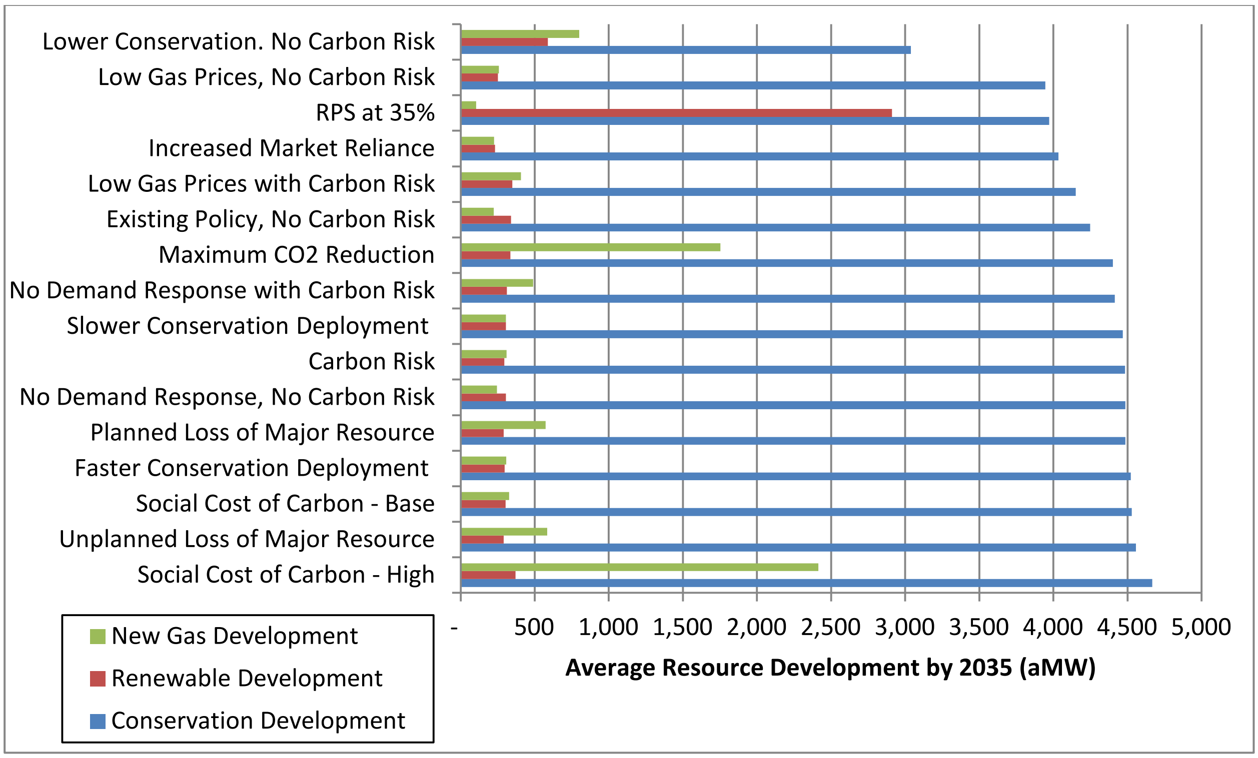
The resource strategy of the Seventh Power Plan is designed to provide the region a low-cost electricity supply to meet future load growth. But it is also designed to provide a low-risk electricity future by ensuring that the region develops and controls sufficient resources to maintain resource adequacy. Therefore the amount and type of resources included in the strategy are designed to meet loads, reduce costs, and help reduce the 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 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 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 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 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 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

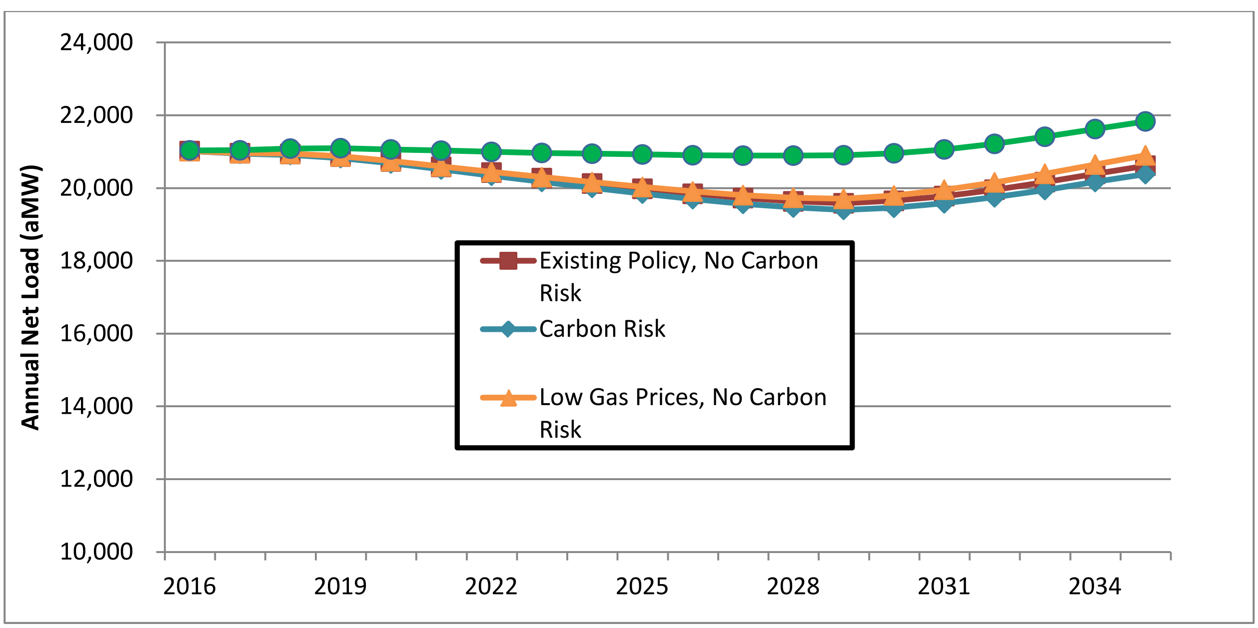
Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,600 average megawatts of conservation. This achievement makes 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 risk 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, No Carbon Risk scenario developed roughly 1200 average megawatts less energy efficiency by 2035 than the Existing Policy, No Carbon Risk scenario. The Lower Conservation scenario had significantly higher ($14 billion) average system cost and exposed the region to much larger ($19 billion) risk than the Existing Policy, No Carbon Risk 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 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 efficiency developed in the Seventh Plan's resource strategy is $36 per megawatt-hour. The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $80 per megawatt-hour, the current cost of utility scale solar photovoltaic systems is approximately $90 per megawatt-hour and Columbia Basin wind costs $108 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,800 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

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

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

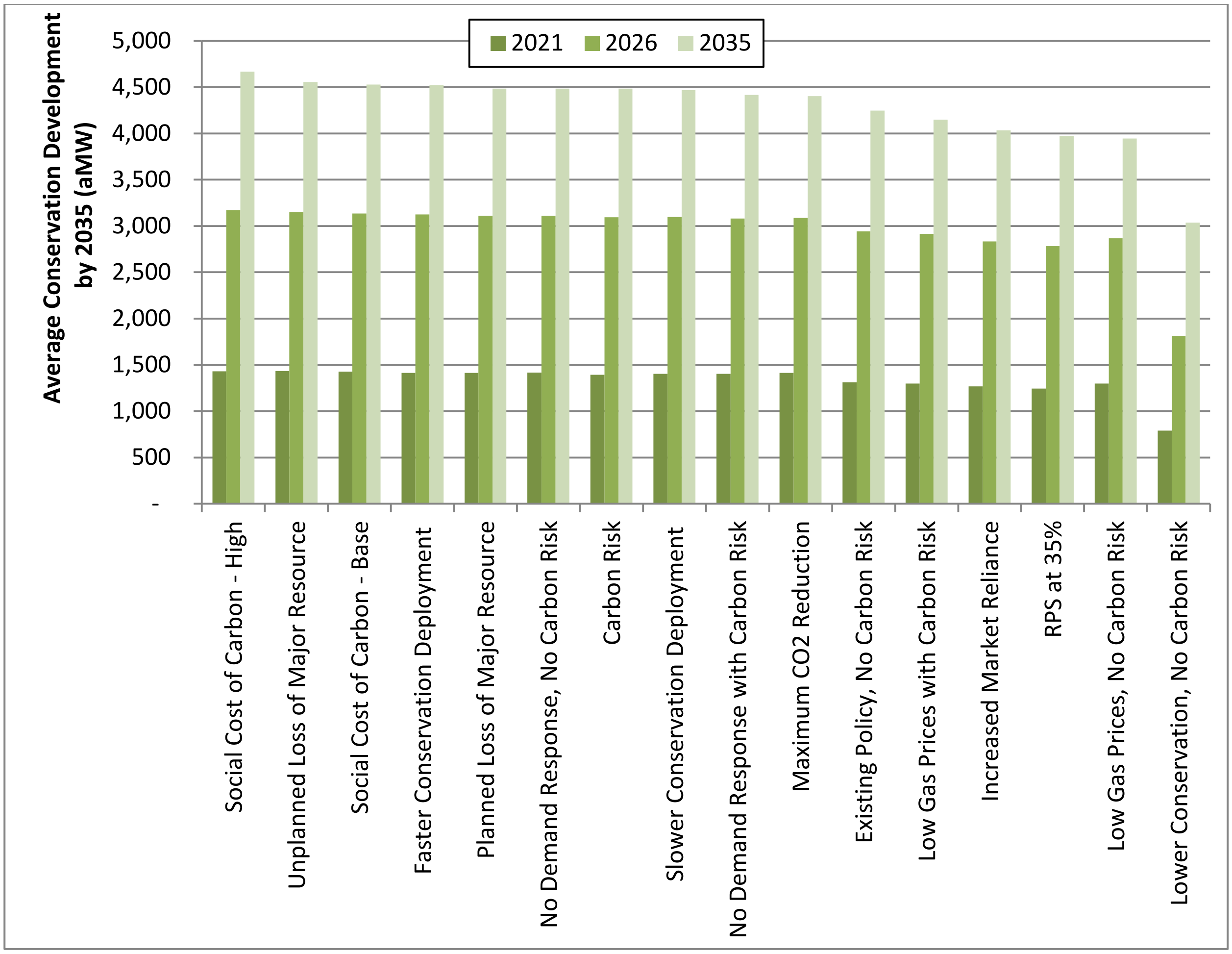


In the Council's analysis, additional resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not needed, the energy and capacity can be 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 all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency are found to be cost-effective.[2] The selection of energy efficiency as the primary new resource does not depend significantly on whether or not carbon 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 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 of just over 5,000 average megawatts.

[2] The only exception is the Lower Conservation, No Carbon Risk scenario which as explicitly designed to develop less energy efficiency.

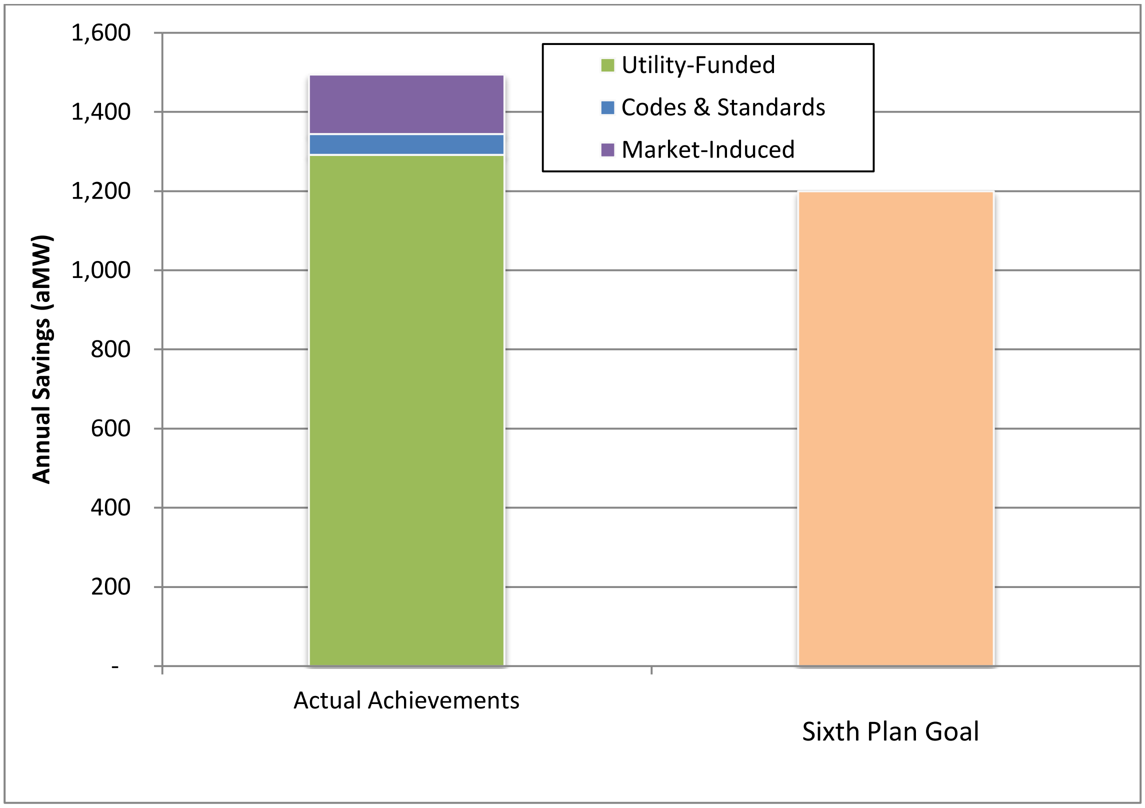
Figure 3 - 3: Amount of Cost-Effective Conservation Resources Developed Under Different Scenarios




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 federal standards and state energy codes and momentum 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

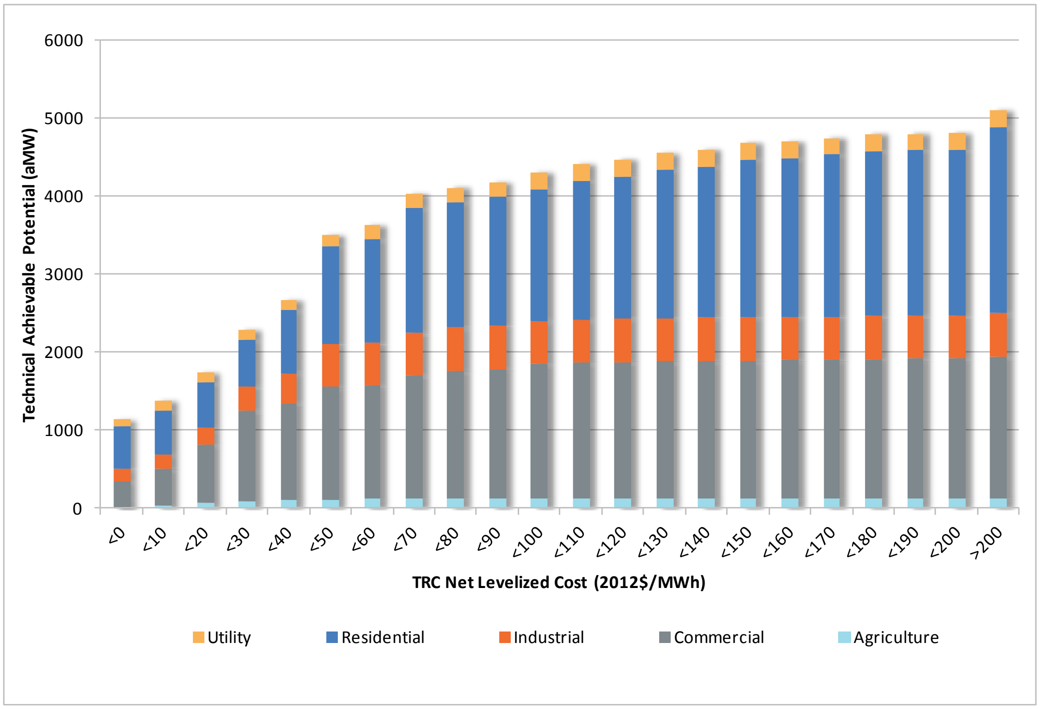



Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified 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 monthly savings of average energy, peak-hour capacity, and minimum-hour loads in 2035 based on 4,485 average annual megawatts of efficiency.

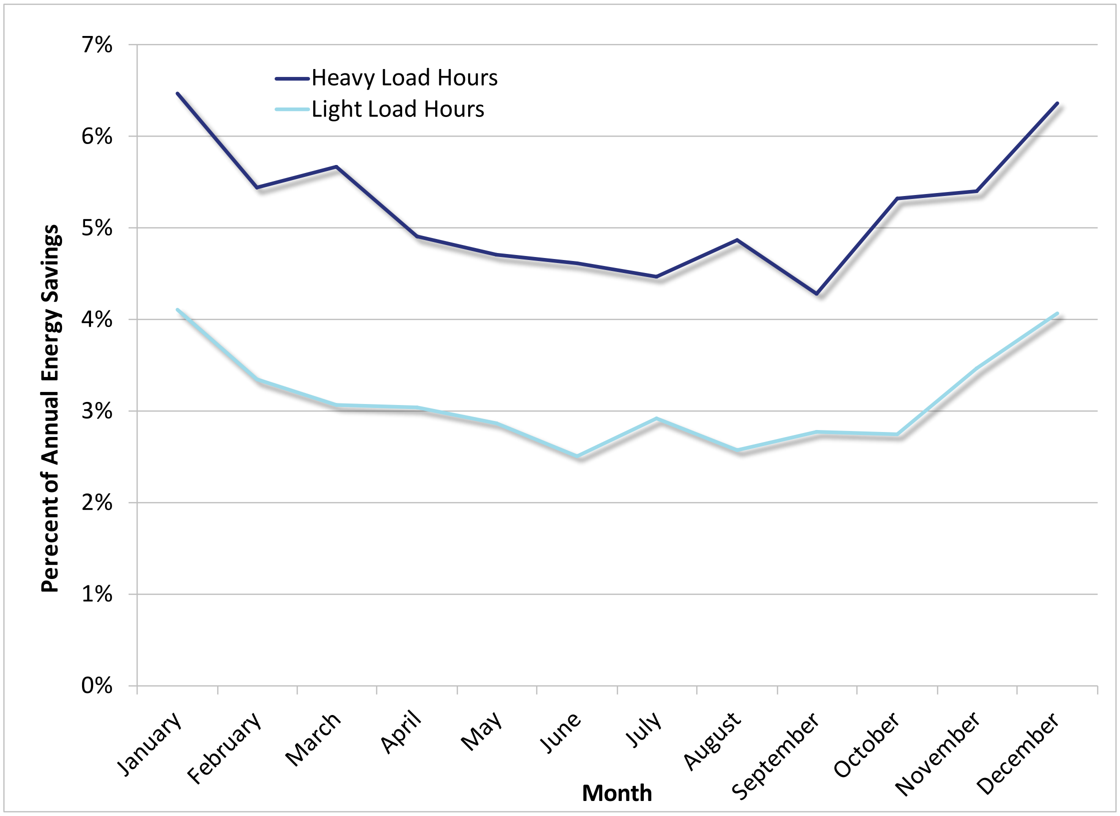
Figure 3 - 5: Cost-Effective Efficiency Potential by Sector and Levelized Cost by 2035




The savings from efficiency actions in the Seventh Power Plan are highest in winter. For example, efficiency improvements that yield average annual savings of 4,485 average megawatts create 10,700 average megawatts of peak hour savings during the winter months.[3]

[3] 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.

Figure 3 - 6: Monthly Shape of 2035 Efficiency Savings



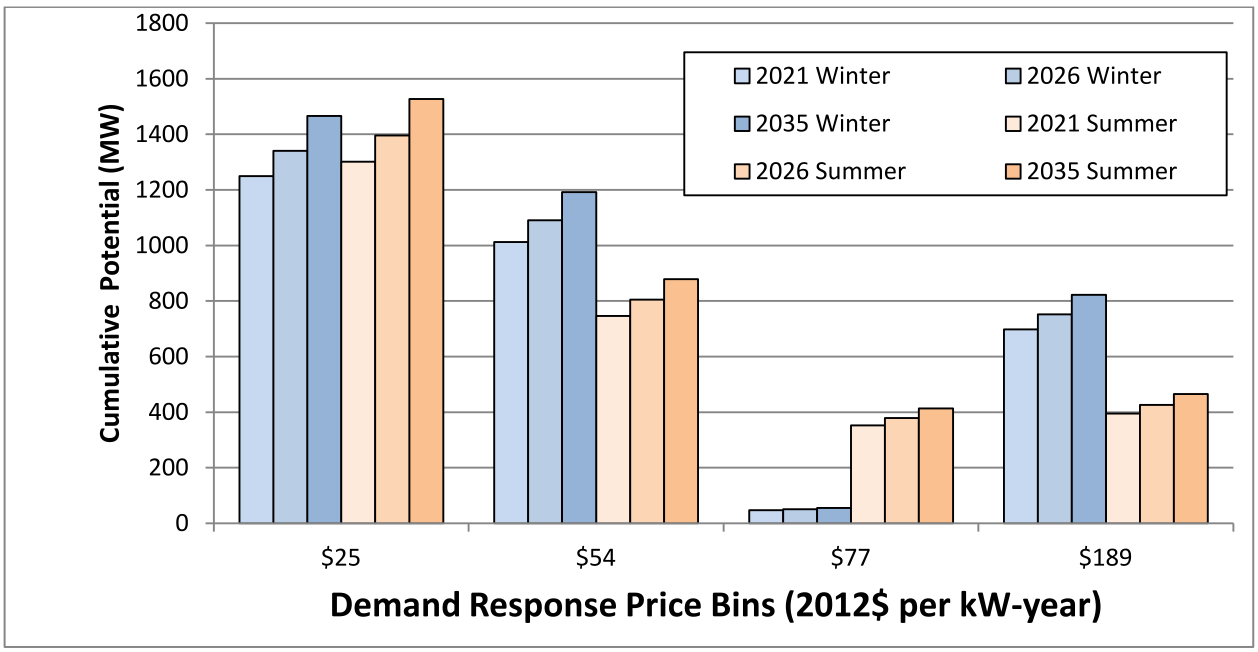

## Demand Response

Demand response resources (DR) are voluntary reductions in customer electricity use during periods of high demand and limited resource availability. As deployed in the Seventh Plan, demand response resources are used to meet winter and summer 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 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 system risk of the least cost resource strategies without demand response was $1 billion higher than in the least cost resource strategies that were able to deploy this resource. Therefore, from the Seventh Plan's analysis it appears that if barriers to development can be overcome; demand response resources could provide significant regional economic benefits.[4]

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



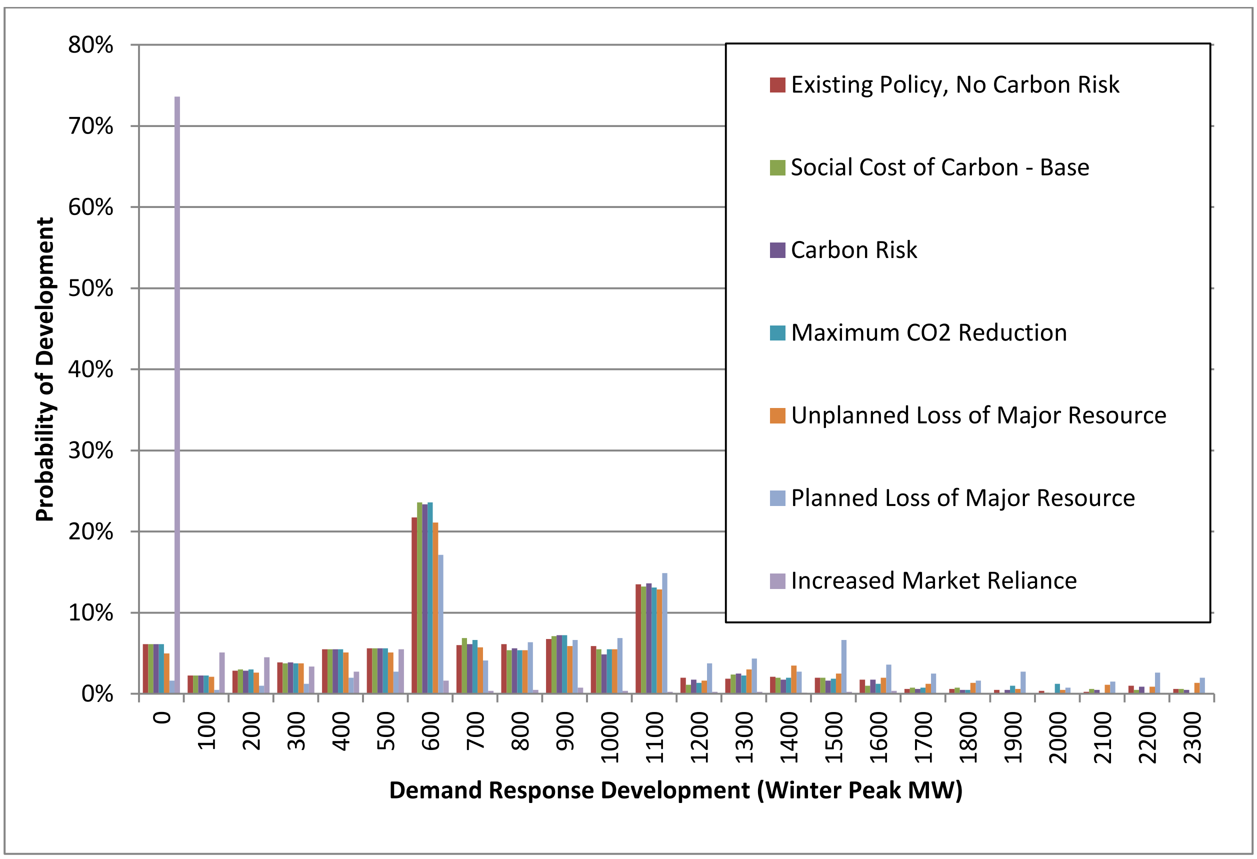

The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources make them particularly valuable because the need for peaking capacity resources 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.

[4] See Chapter 4 for the Action Items the Seventh Plan recommends the region and Bonneville should engage in 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 current 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 risk were also lower. This highlights the sensitivity of the assumed limits on external market reliance used in Council Regional Resource Adequacy Assessment and the potential value of modifying this constraint.

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 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 capacity was added to the region – about equivalent to the development during the previous five year period. By the end of 2014, wind capacity in the region totaled just over 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.

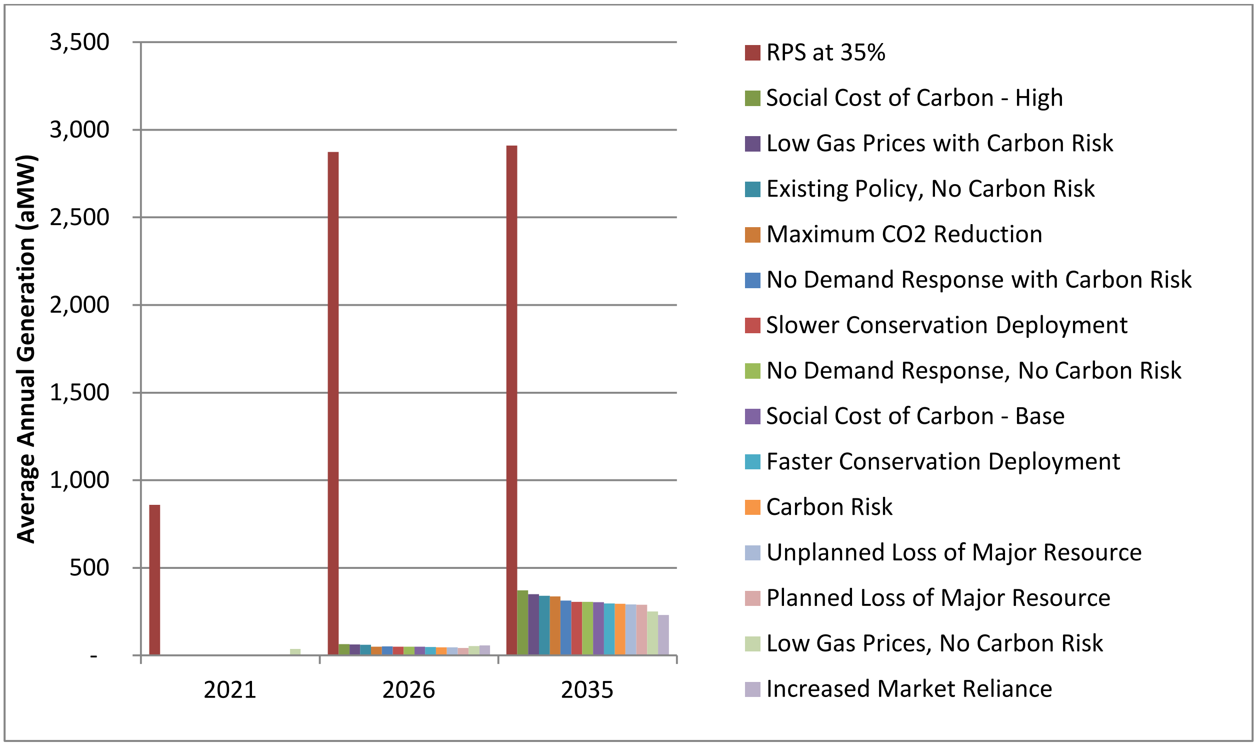
It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

Existing wind is estimated to provide about 2,400 average megawatts of energy generation per year, or about 8 percent of the region's electricity energy supply. However, on a firm capacity basis, wind only provides about 1 percent of the region's total system peaking capability. The Council's current analysis of winds 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 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 are competitive with other generation alternatives. Recent and forecast reductions in solar PV system cost are making utility scale system increasingly cost-competitive. However, renewable generation development in the scenarios tested for the Seventh Plan is driven by state renewable portfolio standards (RPS) and not economics. Figure 3-9 shows the average development of renewable resources across scenarios analyzed for the Seventh 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, renewable developed occurred later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances were drawn down.

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

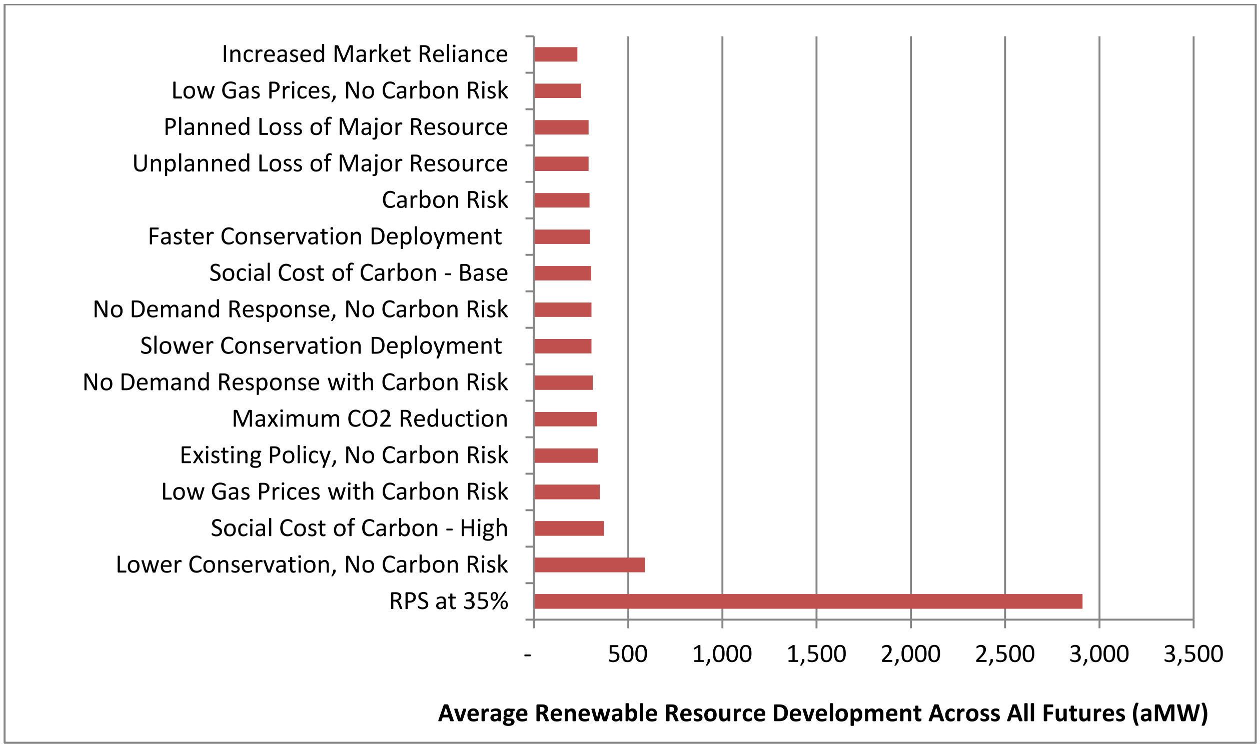



The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 800 futures of demand growth in the carbon-risk scenario, the amount of wind and solar 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 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.

Figure 3-10 shows the amount of additional renewable energy acquired *on average* in the least cost resource strategies in the various scenarios studied. The scenarios are rank-ordered based on the average level of renewable resource development by 2035, with the scenario with the lowest development at the top of the graph. A review of Figure 3-10 shows that the least cost resource strategies in only two scenarios develop more than 500 average megawatts of new renewable resources over the next 20 years. The higher renewable generation in the Lower Conservation, No Carbon Risk scenario reflects higher regional electricity consumption, which increases the amount of renewable energy needed to meet existing RPS. The regulatory requirement in the Increase Renewable Portfolio Standard to 35 Percent (RPS 35%) scenario results in significant new renewable resource development.

The explanation 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.

Figure 3 - 10: Renewable Resource Development by Scenarios and Sensitivity Study – 2035




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 addition renewable development would take place, even under scenarios where the highest social cost of carbon (**Social Cost of Carbon – High**) might be imposed on the power system.

# Natural Gas-Fired Generation

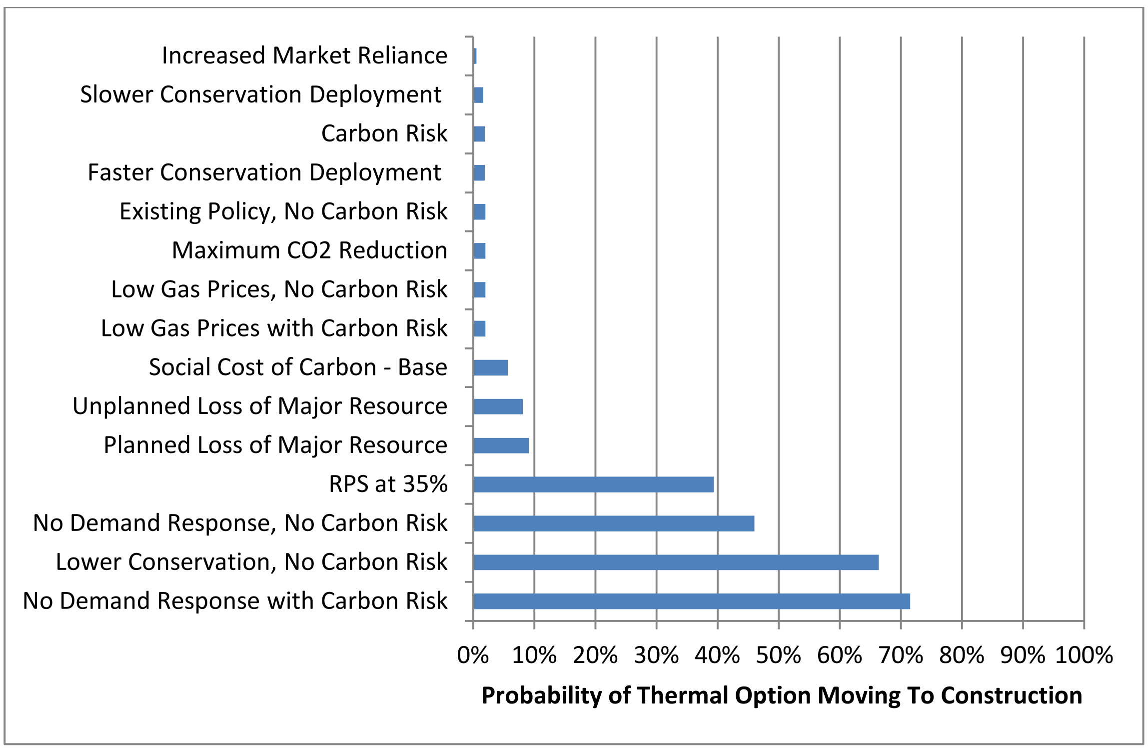
Natural gas is the fourth major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Plan identified the increased use of existing natural gas generation as offering the lowest cost option for reducing regional carbon 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 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 3-11 and 3-12 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 3-11, the probability of gas development is less than ten percent by 2021 in all but four scenarios. The only exceptions to this finding are in the **Increase Renewable Portfolio Standard** 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.

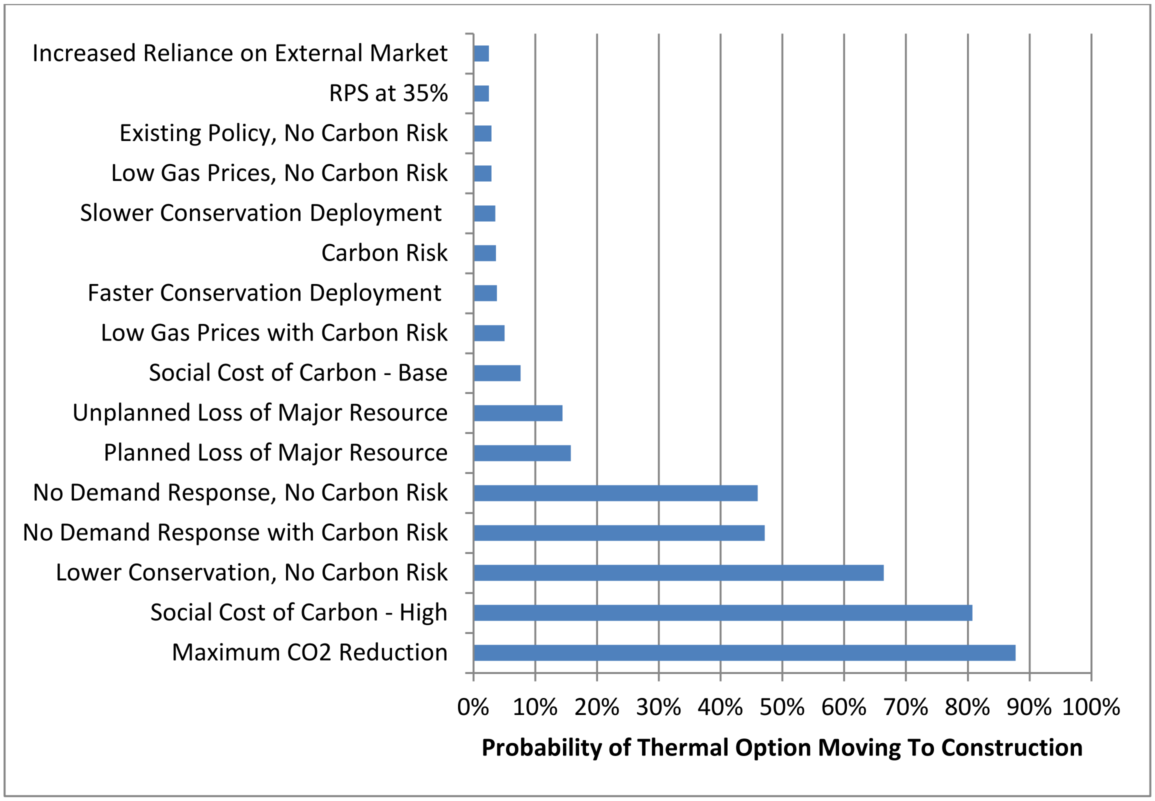
By 2026, Figure 3-12 shows that the probability of converting an option on a new gas-fired thermal plant increases to near 50 percent in scenarios that are unable to develop demand response or where conservation is not acquired as projected and to more than 80 percent in scenarios which retire existing coal and inefficient gas fired generation to reduce regional carbon emissions.

Figure 3 - 11: Probability of New Natural Gas-Fired Resource Development by 2021




The optioning of 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 3-11 and 3-12, this occurs in scenarios that must replace energy generation lost from other resources as in the 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 lower amounts of energy efficiency.

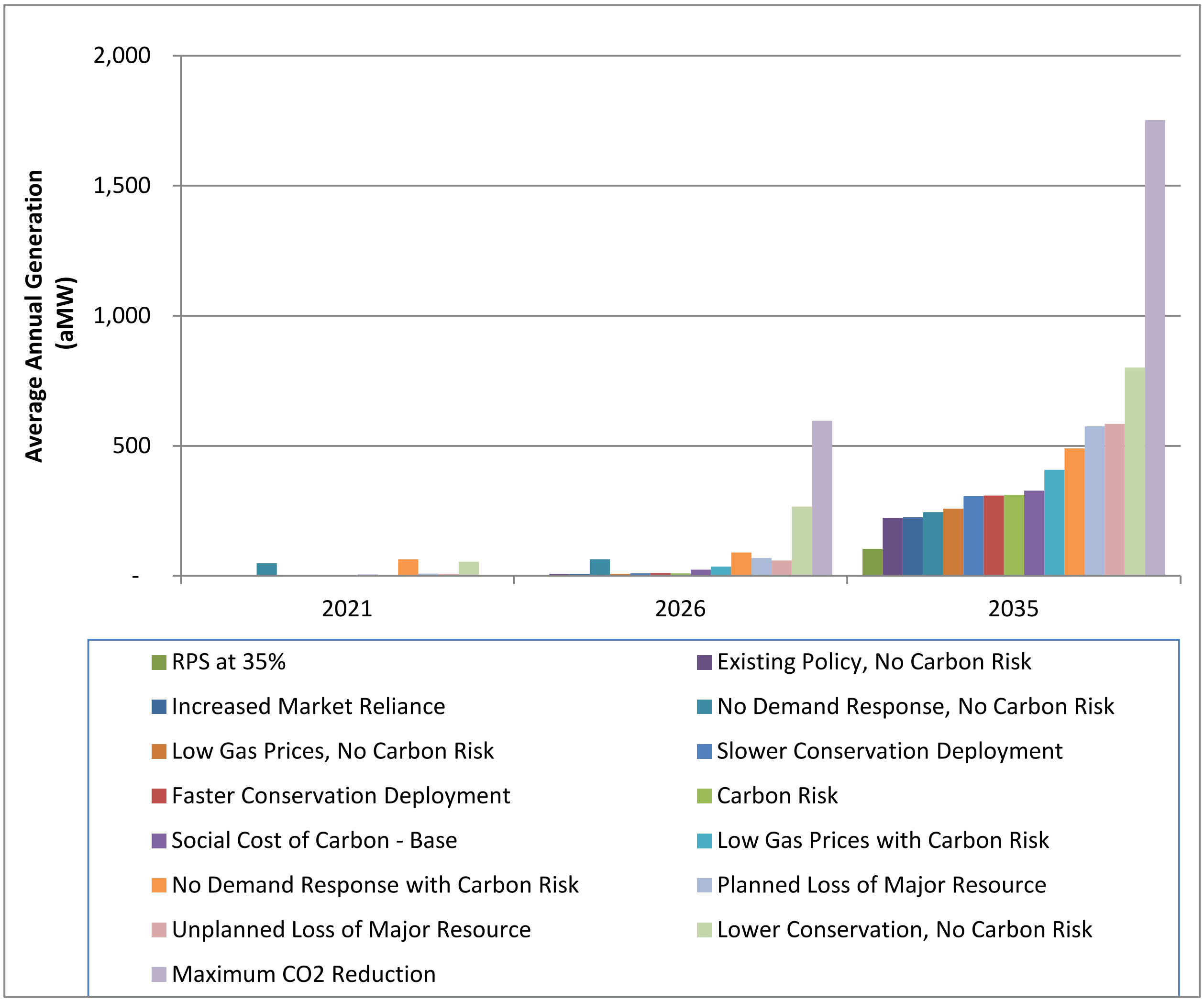
Figure 3 - 12: Probability of New Natural Gas-Fired Resource Development by 2026




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 3-13 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 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 may be 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 Plan.

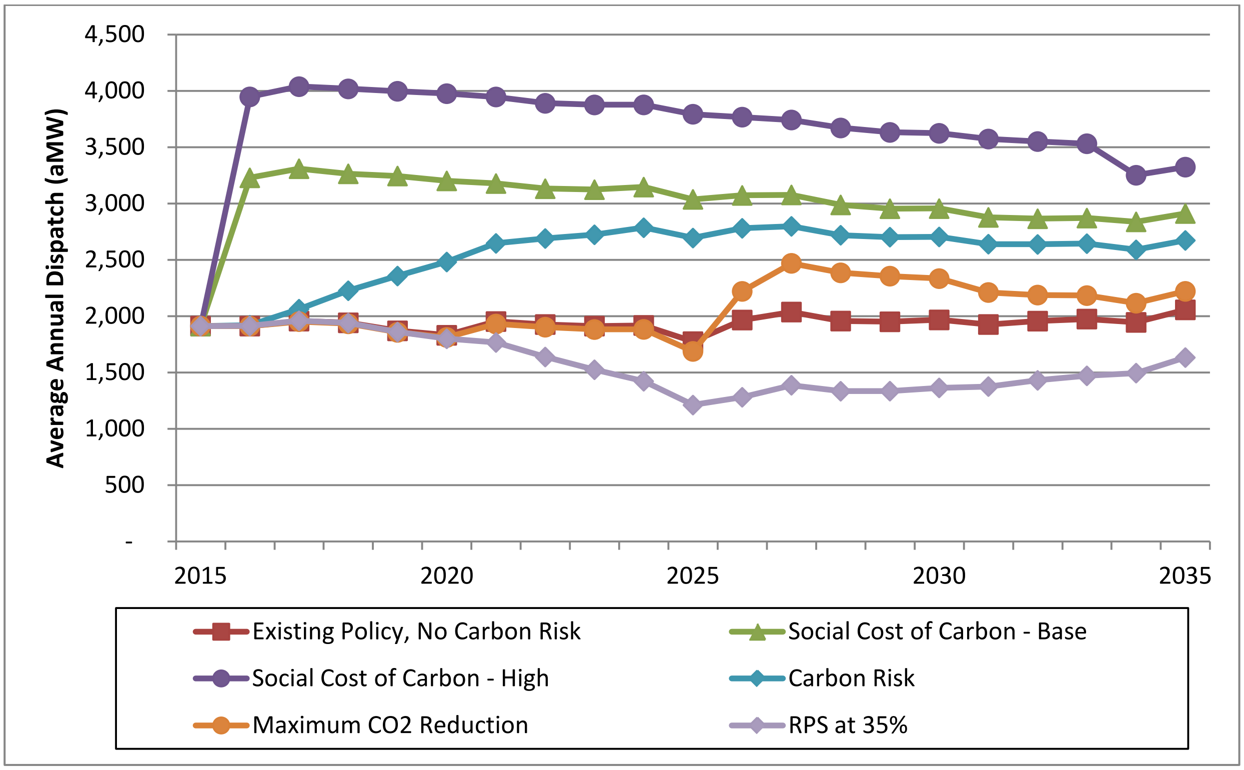
Figure 3 - 13: Average New Natural Gas-Fired Resource Development




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 emissions reduction policies. Figure 3-14 shows the average annual dispatch of the existing natural gas generation in the region through time for the five carbon reduction policy scenarios as well as the Existing Policies, No Carbon Risk Scenario. A review of Figure 3-14 reveals that the annual dispatch of existing natural gas generationing resources increases in response to carbon 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 damage cost in those scenarios. In the **Carbon Risk** scenario, existing natural gas generation gradually increases over time as the cost of carbon increases. In the **Maximum Carbon Reduction** scenario, existing gas generation increases post-2025 when, under this scenario, the entire region's existing coal-fired generation fleet is retired. Under the **Increase Renewable Portfolio Standard to 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 - 14: Average Annual Dispatch of Existing Natural Gas-Fired Resources




## 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-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 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 Plan reveal the symptoms and scope of the problem.

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 risk because they delayed or avoided the need for new resource development within the region. Figure 3-15 shows the average net (i.e., exports minus imports) exports for their least cost resource strategies across six scenarios.

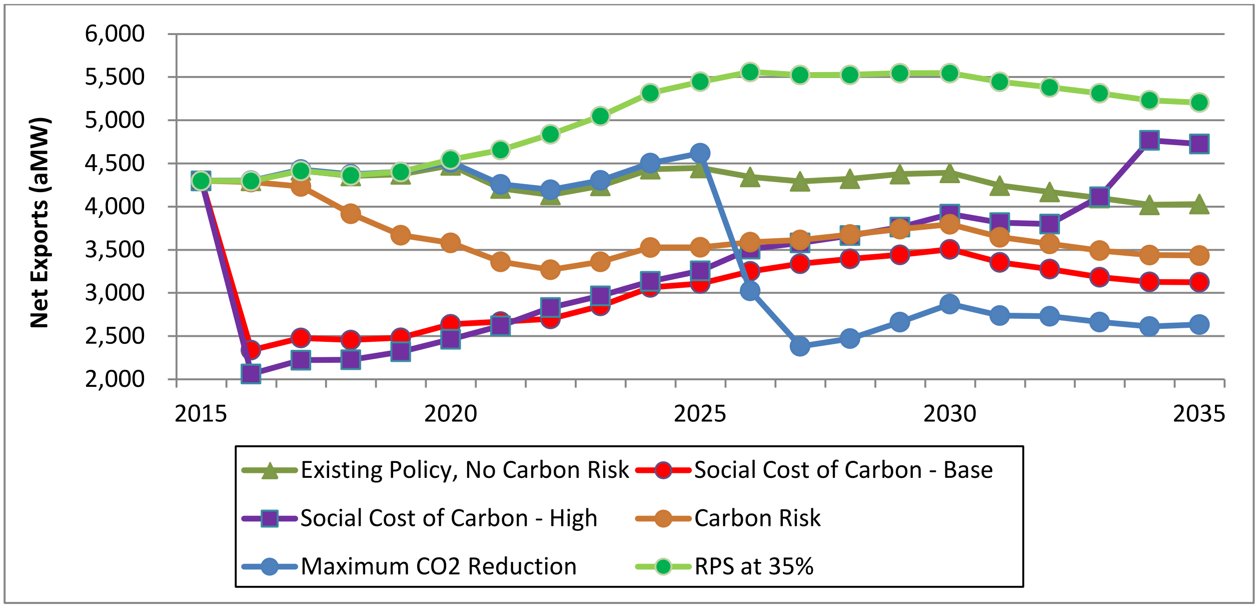
Inspection of Figure 3-15 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy, No Carbon Risk** scenario exports decline slightly after 2021 and 2026 following the closure of coal plants that currently serve the region. 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 damage costs are imposed in 2016 (e.g. **Social Cost of Carbon-Base** and **Social Cost of Carbon-High**), net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon 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 **Increase Renewable Portfolio Standard to 35 Percent** scenario, regional net exports expand significantly over time as the region develops large amounts 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[5] which can be terminated with five year notice.[6] While all of the region's utilities must be offered the opportunity to purchase excess Federal power, as required by the NW Power Act, 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.

Figure 3 - 15: Average Annual Net Regional Exports for Least Cost Resource Strategies




## Develop Long-Term Resource Alternatives

The sixth 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 indentifies 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 the status and

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

cost of potential no-carbon or low-carbon generation. The latter includes renewable technologies such as 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 seventh 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 risk) over the widest range of future conditions. This means that during the period covered by the Seventh 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 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 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 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 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 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 emissions and the specific cost of attaining carbon 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.

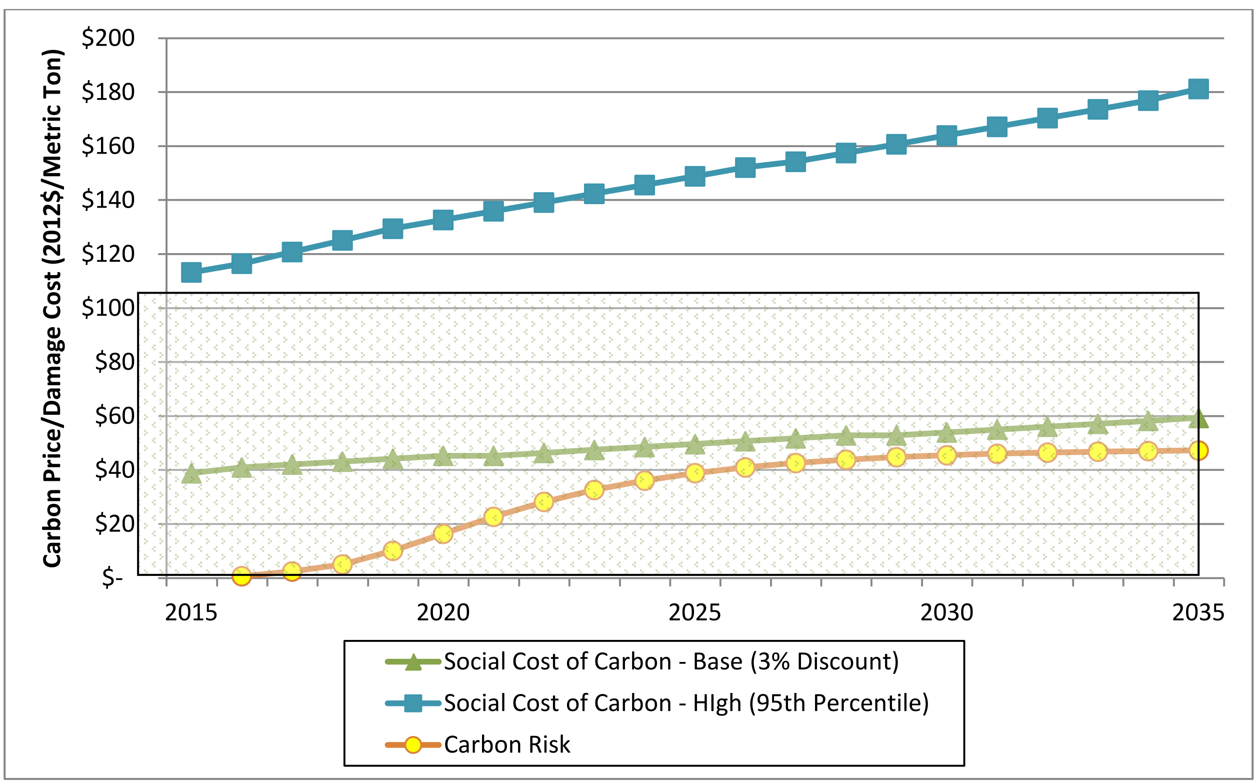
Chapter 15 discusses the results of the Council's analysis of alternative carbon emissions reduction policy scenarios in more detail.

Three "carbon 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 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 emissions would be the maximum society should invest to avoid such damage.

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

Figure 3-16 shows the two US Government Interagency Working Group's estimates used for the two **Social Cost of Carbon** scenarios and the range (shaded area) and average carbon prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Risk** scenario.

Figure 3 – 16: Carbon Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis




Two other carbon policies were tested that did not involve using carbon pricing to reduce emissions. The first of these, the **Maximum Carbon Reduction**, **Existing Technology** scenario was designed to reduce carbon emissions by deploying all currently economically viable technology. Under this scenario 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.

The second "non-price" policy option tested was the **Increase Renewable Portfolio Standard to 35 Percent** scenario. Under this scenario, the region's reliance on carbon-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.

Carbon prices or estimated damage costs are not included in the **Existing-Policy, No Carbon Risk** scenario, nor are they included in the **Maximum Carbon Reduction**, **Existing Technology** or the **Increase Renewable Portfolio Standard to 35 Percent** scenarios. Therefore, comparing the cost and emissions from these scenarios provides insights into the impact of alternative policy options for reducing carbon emissions.

Table 3-1 shows the average system costs and carbon emissions for the six scenarios and sensitivity studies conducted to specifically evaluate carbon emissions reductions policies (and risks) for the development of the Seventh 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 "cost" (i.e. tax revenues). It also shows the average carbon 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.

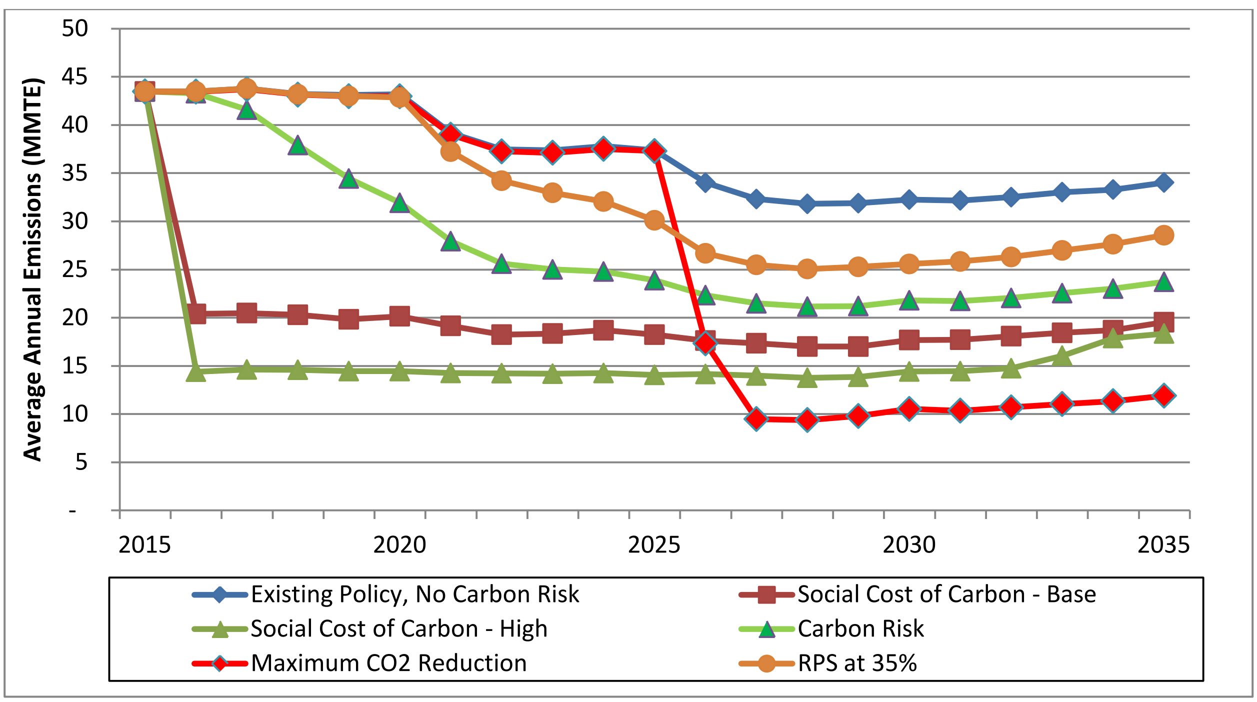
Table 3 - 1: Average System Costs and PNW Power System Carbon Emissions by Scenario

| **Scenario** | System Cost w/CO2 Cost (billion 2012$ | System Cost w/o CO2 Cost (billion 2012$) | 2035 CO2 Emissions (MMTE) |
|---|---|---|---|
| **Existing Policy, No Carbon Risk** | $130 | $87 | 34 |
| **Social Cost of Carbon - Base** | $132 | $88 | 20 |
| **Social Cost of Carbon - High** | $157 | $89 | 18 |
| **Carbon Risk** | $133 | $88 | 24 |
| **Maximum CO2 Reduction, Existing Technology** | $158 | $107 | 12 |
| **Increase Renewable Portfolio Standard to 35%** | $151 | $121 | 29 |

Table 3-1 shows the **Existing Policy, No Carbon Risk** scenario which assumed no additional carbon 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 emissions in 2035 of 34 million metric tons. It has an average present value system cost of $87 billion (2012$). Both the **Social Cost of Carbon – Base** (SCC-Base) and **Social Cost of Carbon – High** (SCC-High**)** scenarios reduce carbon emissions to about between 18 – 20 million metric tons in 2035 and these scenarios increased average system cost $1 - $2 billion over the **Existing Policy, No Carbon Risk** scenario. Under the **Carbon Risk** scenario, 2035 carbon emissions were reduced to 24 million metric tons, or 10 million metric tons below the **Existing Policy, No Carbon Risk** scenario, also increasing average system cost by around $1 billion over the **Existing Policy, No Carbon Risk** scenario. The **Maximum Carbon Reduction** scenario reduces 2035 carbon emissions to 12 million metric tons. The estimated cost of this much lower carbon emissions rate is about $20 billion over the **Existing Policy, No Carbon Risk** scenario. The **Increase Renewable Portfolio Standards to 35%** scenario reduces 2035 carbon emissions to just under 30 million metric tons, a reduction of around 5 million metric tons per year from the **Existing Policy, No Carbon Risk** scenario. This scenario also increased average system cost by around $34 billion over the Existing Policy, No Carbon Risk scenario.

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 3-17 shows the annual emissions level for each scenario. A review of Figure 3-17 reveals that the two social cost of carbon scenarios, which assume carbon damage costs are imposed in 2016, immediately reduce carbon emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Plan. In contrast, the other three carbon reduction policies phase in over time, so there cumulative impacts are generally smaller.

Figure 3 - 17: Average Annual Carbon Emissions by Carbon Reduction Policy Scenario




The **Carbon Risk** and **Increase Renewable Portfolio Standards to 35%** scenarios gradually reduce emissions, while the **Maximum Carbon Reduction** scenario dramatically reduces emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon 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 reduction policy scenarios compared to the **Existing Policy, No Carbon Risk** scenario. It also shows the average system cost per million metric ton of carbon reduction for these five carbon reduction policy options, net of carbon "tax revenues." Table 3-2 reveals that three carbon pricing policies have roughly comparable cost per unit of carbon emission reduction based on cumulative emissions reductions. The **Maximum Carbon Reduction** scenario, as can be seen from Figure 3-17, results in the lowest average annual carbon emissions from the regional power system by 2035. The average cost per ton of carbon reduction for this scenario is significantly higher than the three carbon pricing policies, but much lower than average cost per ton of carbon reduction in the **Increase Renewable Portfolio Standards to 35%** scenario.

Note that under the two **Social Cost of Carbon** scenarios and the **Carbon 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 emission reduction scenarios would likely be higher and much closer to the **Maximum Carbon Reduction** scenario

Table 3 - 2: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies Compared to Existing Policies, No Carbon Risk Scenario

| CO2 Emissions - PNW System 2016 - 2035 (MMTE) | Cumulative Emission Reduction Over Existing Policy, No Carbon Risk Scenario (MMTE) | Incremental Average System Cost of Cumulative Emission Reduction Over Existing Policy, No Carbon Risk Scenario (2012$/MMTE) |
|---:|---:|---:|
| **Carbon Risk** | 196 | $2 |
| **Social Cost of Carbon - Base** | 360 | $4 |
| **Social Cost of Carbon - High** | 438 | $3 |
| **Maximum CO2 Reduction** | 217 | $90 |
| **Increase RPS to 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 emissions will continue beyond 2035, as will their carbon emissions impacts. These "end-effects" could alter the perceived relative cost-efficiency of carbon 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** scenario could exceed those from the **Social Cost of Carbon-Base** scenario because by 2035 the **Maximum Carbon Reduction** 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.

## Federal Carbon Dioxide Emission Regulations

As the Seventh 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 CO2 emissions by 32% from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30%. 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 CO2 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 emission rate (pounds of CO2/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 CO2 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 CO2 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 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 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 CO2 Emissions Limits[7]

| 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[8]. 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 CO2 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 3-18 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 Plan. The interim and final EPA carbon dioxide emissions limits aggregated from the state level to the regional level is also show in this figure (top heavy line).

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[7] 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).

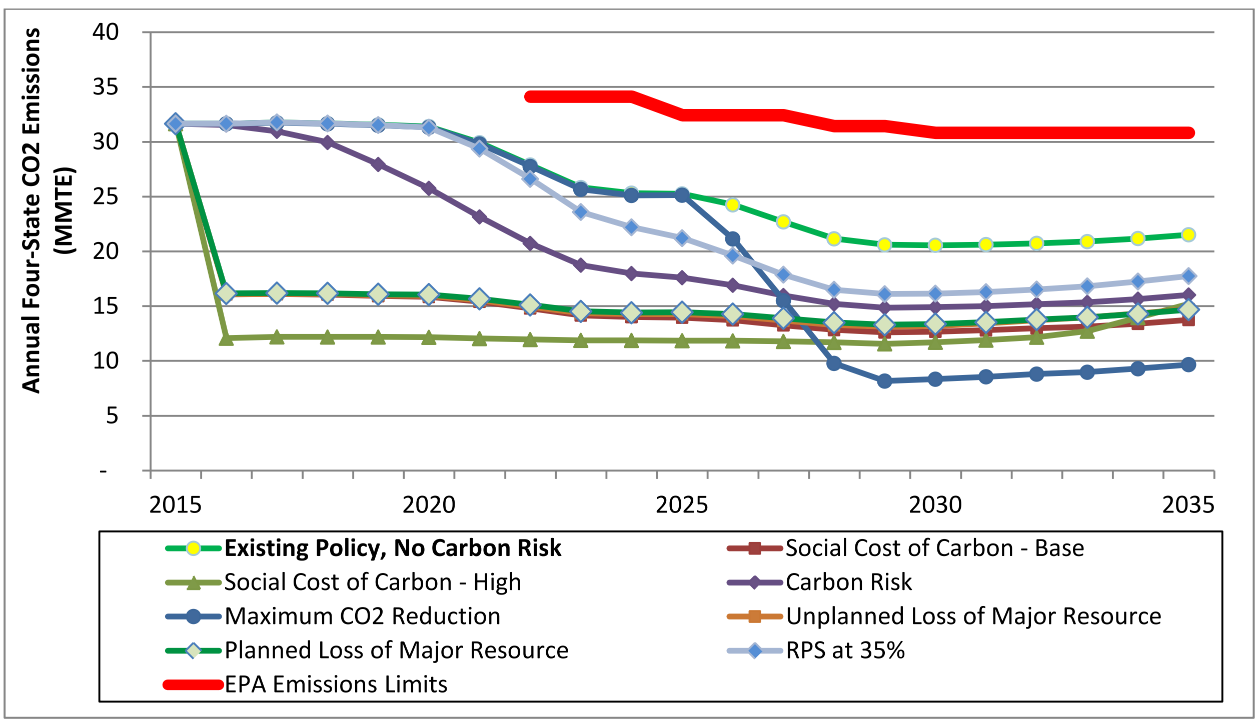
[8] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five 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 3-18 shows all of the scenarios evaluated result in average annual carbon 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 emissions rule should be achievable without adoption of additional carbon 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 3-18 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 to meet regional adequacy standards for energy and capacity rather than to serve external markets.

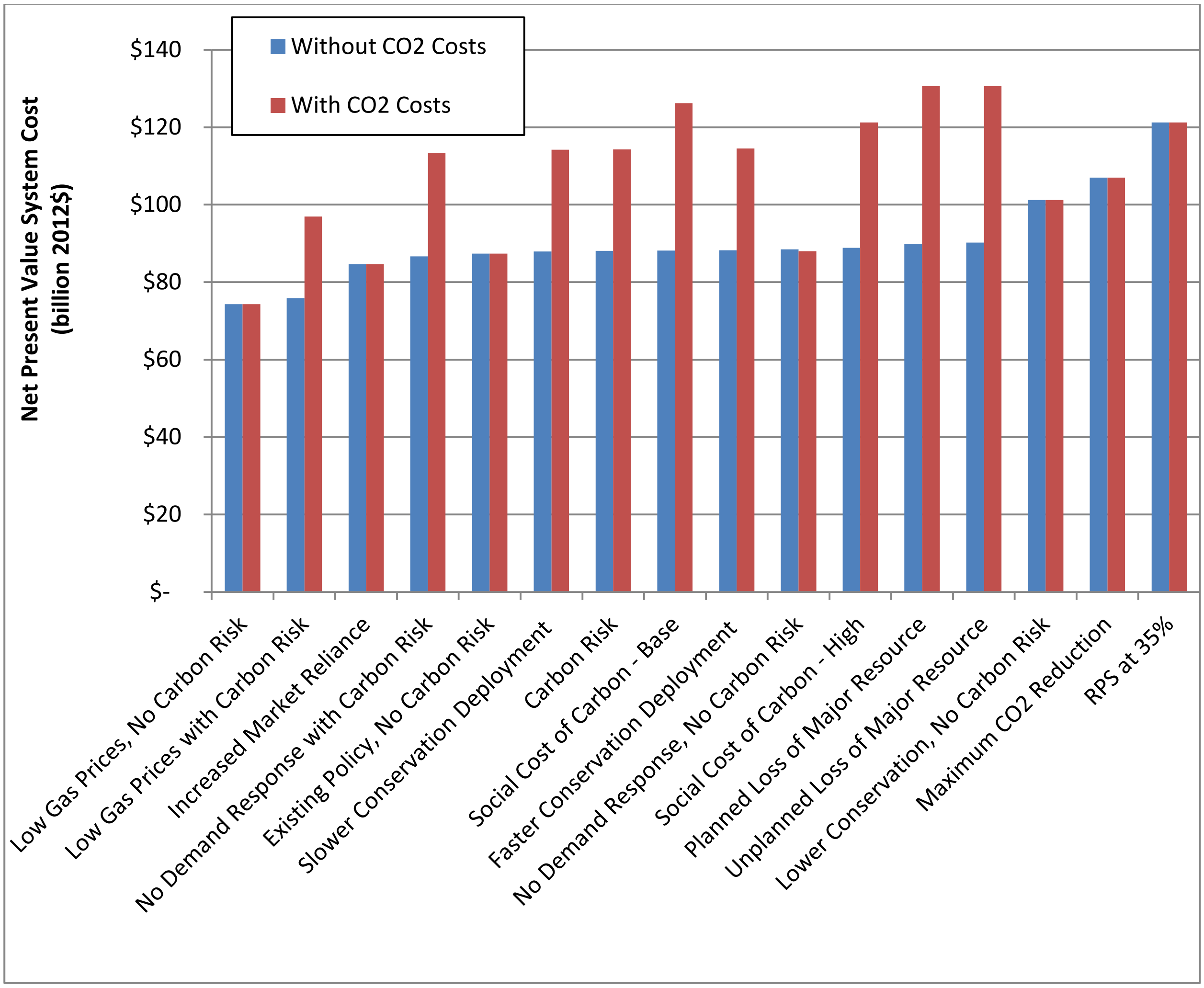
Figure 3 – 18: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



# 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 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 Plan. Figure 3-19 also shows the present value of power system costs both with and without assumed carbon emissions costs. That is, the scenarios that assumed some form of carbon price include not only the direct cost of building and operating the resource strategy, but the costs of CO2 assumed in those scenarios. Therefore, in Figure 3-19 the present value system cost of the least cost resource strategies for the scenarios that do not assume that either carbon regulatory risk cost or damage are the same with and without consideration of CO2 costs. For example, the Low Gas Prices, No Carbon Risk and Existing Policy, No Carbon Risk scenarios have the same average system cost with and without CO2 costs.

Figure 3 – 19: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Cost




Inspection of Figure 3-19 shows that, exclusive of carbon 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**, **Increased Market Reliance, Lower Conservation, No Carbon Risk** and **Renewable Portfolio Standard at 35 Percent** scenarios, have average system costs that differ significantly from the **Existing Policy, No Carbon Risk** 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** 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, No Carbon Risk** 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, No Carbon Risk** 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%** 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.

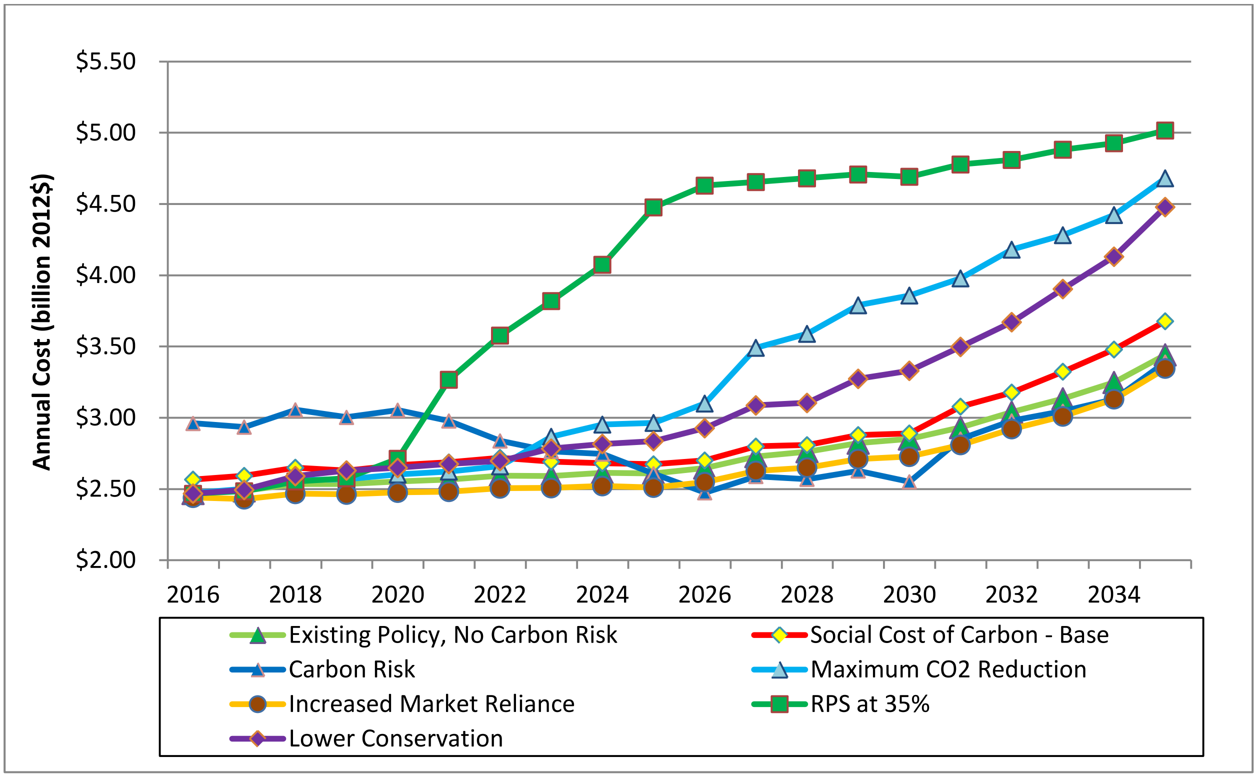
Table 3 – 4: Average Net Present Value System Cost with Carbon Cost and Incremental Cost Compared to Existing Policy, No Carbon Risk Scenario

| Scenario | System Cost Without Carbon Cost (billion 2012$) | Incremental Cost Over Existing Policy, No Carbon Risk Scenario (billion 2012$) |
|---|---|---|
| **Existing Policy, No Carbon Risk** | $87 | |
| **Social Cost of Carbon - Base** | $88 | $0.8 |
| **Social Cost of Carbon - High** | $89 | $1.5 |
| **Carbon Risk** | $88 | $0.7 |
| **Maximum CO2 Reduction** | $107 | $19.6 |
| **Unplanned Loss of Major Resource** | $90 | $2.8 |
| **Planned Loss of Major Resource** | $90 | $2.5 |
| **Faster Conservation Deployment** | $88 | $0.8 |
| **Slower Conservation Deployment** | $88 | $0.6 |
| **Increased Market Reliance** | $85 | ($2.7) |
| **RPS at 35%** | $121 | $33.9 |
| **Lower Conservation, No Carbon Risk** | $101 | $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 regulatory compliance cost or damage costs**: Existing Policy, No Carbon Risk, Maximum Carbon Reduction, Lower Conservation, No Carbon Risk** and **Renewable Portfolio Standards at 35 Percent** so their forward going costs are identical with and without carbon cost. In order to compare the direct cost of the actual resource strategies resulting from carbon pricing policies with these four scenarios it is necessary to remove the carbon 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 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 3-20 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 Risk scenario include the cost of carbon regulation or carbon damage.

Figure 3 - 20: Annual Forward-Going Power System Costs, Excluding Carbon Costs

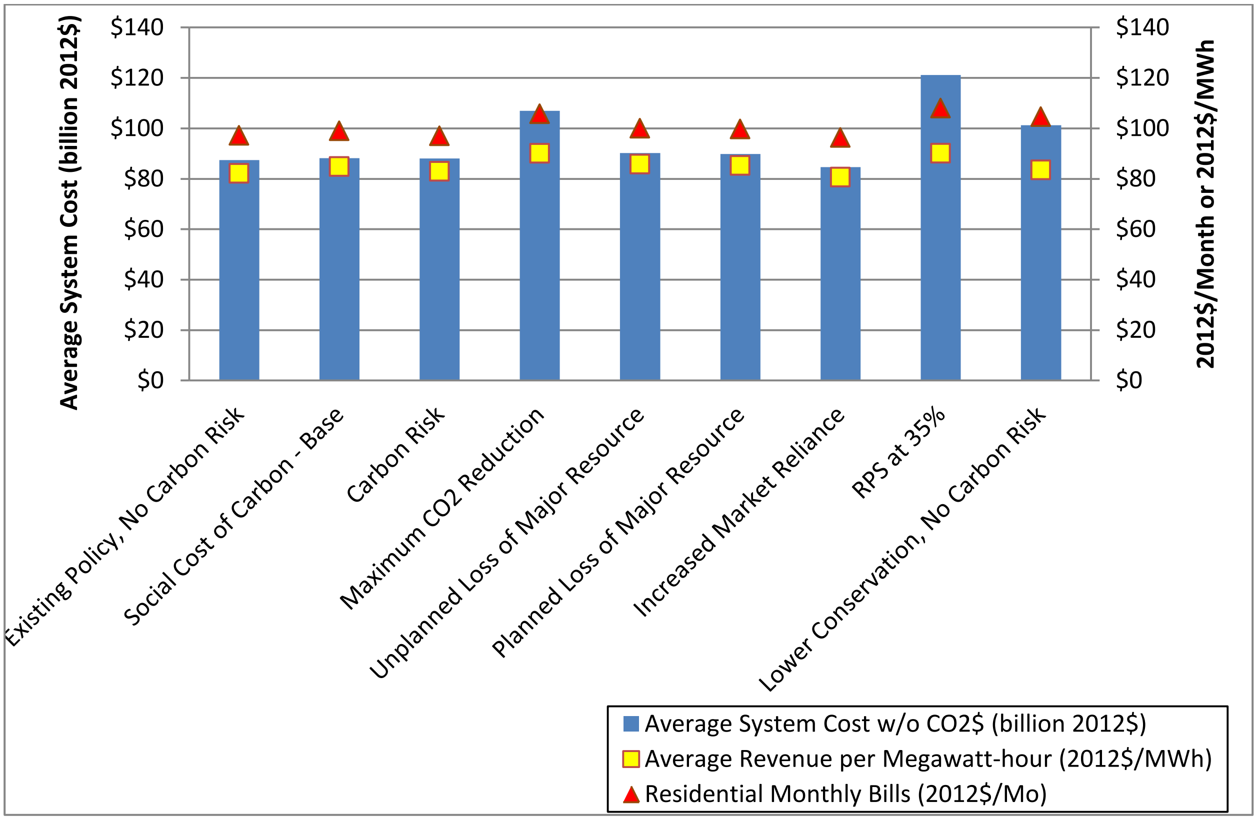



A review of Figure 3-20 shows that the **Carbon Risk** and **Increased Market Reliance** scenarios have slightly lower annual cost post-2026 than the **Existing Policy, No Carbon Risk** scenario. The **Lower Conservation, No Carbon Risk** resource strategy shows higher annual system cost than all but two other resource strategies, the **Increase Renewable Portfolio Standard and Maximum Carbon Reduction** least cost resource strategies. The highest forward going revenue requirement, well above even the **Maximum Carbon Reduction** 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 some of the scenarios.

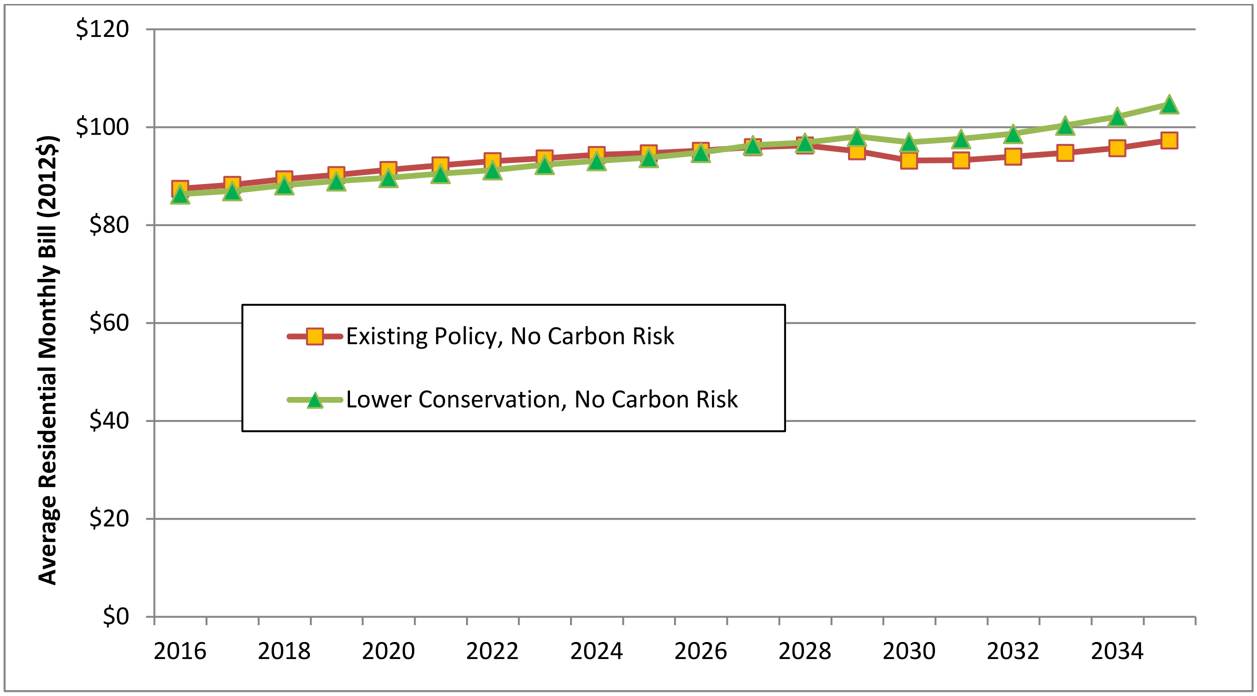
Figure 3-21 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 3-21 are average revenue requirement per megawatt-hour which include both monthly 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 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 - 21: System Costs, Rates, and Monthly Bills, Excluding Carbon Costs




As can be seen in Figure 3-21, 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, No Carbon Risk** scenario has an average system cost of $101 billion, compared to the **Existing Policy, No Carbon Risk** resource strategy's $87 billion. Even with nearly a $14 billion higher average system cost the **Lower Conservation, No Carbon Risk** resource strategy and the **Existing Policy, No Carbon Risk** scenario have nearly equal average revenue requirement per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy, No Carbon Risk** scenario and $84 per megawatt-hour for the Lower Conservation, No Carbon Risk scenario. However, **the Lower Conservation, No Carbon Risk** scenario's average monthly bill is about $105, about $6 per month higher than **the Existing Policy, No Carbon** risk 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 3-22 illustrates how efficiency improvements lower electricity bills.

Figure 3 - 22: Residential Electricity Bills With and Without Lower Conservation



# CHAPTER 4: SEVENTH POWER PLAN 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 Power 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 both 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 Power Plan will require continued aggressive actions by the region. While the aggressive pursuit of this conservation is the primary focus of the power plan's actions 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.

Combined with investments in renewable generation as required by state renewable portfolio standards, improved efficiency and demand response resource 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.

The power 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.

# 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, Northwest Energy Efficiency Alliance (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 outlined below, with further description provided in Appendix G. A cost-effective measure will have a benefit-to-cost ratio greater than or equal to one, where the terms are defined as:

$$\frac{Benefit}{Cost} = \frac{NPV(energy + capacity + other\ fuel + NEI + avoided\ periodic\ replacement)}{NPV(capital\ cost * (1 + admin) + annual\ O\&M + other\ fuel + NEI + periodic\ replacement)}$$

Where *NPV* is the net present value and:

$$energy = kWh_{i,bb} * ((MP + C)_i + RMC) * (1 + 10\%)$$

and

$$capacity = kW_{peak,bb} * (T_{avoid} + D_{avoid} + Gen_{avoid}) * (1 + 10\%)$$

The terms are defined as:

*NEI* = non-energy impacts

*admin* = administration cost adder

*kWh* = energy saved by time segment *i* (e.g. heavy/light load hours, monthly)

$kW_{peak}$ = winter peak power saved

*bb* = busbar

*MP* = market price forecast ($/kWh) by time segment *i*

*C* = carbon cost forecast ($/kWh) by time segment *i.*

*RMC* = risk mitigation credit for stochastic variation in inputs ($/kWh)

$T_{avoid}$ = deferred transmission capacity credit ($/kW-yr)

$D_{avoid}$ = deferred distribution capacity credit ($/kW-yr)

$Gen_{avoid}$ = deferred generation capacity credit ($/kW-yr)

*10%* = Regional Act conservation credit

**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 Power Plan's analysis identified a potential need to add resources, including conservation and demand response, to maintain an adequate and reliable system. Further, 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 Power 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 Resource 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 Resource 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 modest 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 plan implementation and adapt as needed the Council, in cooperation with regional stakeholders, will conduct:

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

The Mid-Term Assessment will include high-level metrics to measure plan implementation.

# Regional Actions Supporting Plan Implementation

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

**REG-1** **Provide continued support for the Northwest Energy Efficiency Alliance (NEEA).** [Bonneville, Utilities, and Energy Trust of Oregon] Provide continued support for NEEA necessary to implement its 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 Power 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 for which NEEA is the leading implementer are:

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

- REG-9. Develop strategies to coordinate energy-efficiency planning within region.
- MCS-4. Develop a regional work plan to provide adequate focus on emerging technologies to help ensure adoption.
- REG-6. Conduct regional sector-specific stock assessments.
- MCS-7. Monitor and track code compliance in new buildings.
- REG-7. Understand impact of codes and standards on the load forecast and conservation targets.

New activities not included in the 2015-2019 Business Plan:

- MCS-6. Develop and deploy best-practice guides for the design and operations of emerging industries.
- ANLYS-5. Develop robust set of end-use load shapes with plan to update over time.
- ANLYS-8. Prioritize research and adoption of energy-efficiency measures that also save water.
- RES-5. Support regional market transformation for demand response.

**REG-2** **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-3** **Collaborate on Regional Operating Reserve Planning Data Collection.** [Utilities, Bonneville, and Utility Regulators] Utilities should include their planning assumptions for the provision of operating reserves in their Integrated Resource Plans and Bonneville's in its Resource Program. These assumptions should emphasize reliability ahead of economic operations, that is, reasonable estimates for times of power system stress. This should include the following

- 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 hydro 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-4** **Conduct regular conservation program impact evaluation to ensure that reported 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 the program impact evaluation guidelines and standards that assure reliability of energy and capacity savings achieved and inform the adaptive management of 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 the regional conservation progress report.

**REG-5** **Report on progress toward meeting 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 Power Plan implementation, the Regional Technical Forum should collect data annually from Bonneville, Utilities, Energy Trust of Oregon, and NEEA to report on progress toward meeting the plan's conservation targets and objectives. This Regional Conservation Progress report should address 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 to acquire cost-effective conservation. 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-6** **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. 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 for 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-7** **Understand impact of codes and standards on the 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, collecting the necessary data, such as saturation of appliances, number of units installed, and unit savings. These 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 Power Plan. NEEA should produce an annual report on the savings impact of standards and updated models to link savings and load forecast estimates.

**REG-8** **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 holistic approach to savings. A report on data analysis approaches and availability barriers should be completed by the end of 2017.

**REG-9** **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] In order to achieve all cost-effective conservation, all customer segments should participate in programs. 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: mid-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, one approach could be for utilities to ensure data collection from programs includes demographic/firmographic data to identify the existence of any HTR segments. BPA 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. The utilities and Bonneville should report to the Council on proportion of participation from HTR segments and how these data were collected. The first report should occur in 2018, and then annually thereafter. After the first report, the regional utilities should devise strategies to improve participation by the identified HTR segments in acquiring cost-effective conservation.

**MCS-2** **Develop program to assess and capture distribution efficiency savings.** [RTF, Bonneville, Utilities] 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 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 Power 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 four 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 should continue to meet its share of the Seventh Power 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 identifying Bonneville needs for additional resources to maintain reliability. (See Action Item RES-3 for specifics)**

**BPA-3** **Continue efforts to establish demand response.** 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 remove barriers to successful implementation including:

- 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 the barriers to the development of demand response by Bonneville and implement 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 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 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'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 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 should work with its customers to create incentives that help mitigate generation oversupply conditions.

## Council Actions Supporting Plan Implementation

**COUN-1** **Form Demand Response Advisory Committee.** 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 Pacific Northwest Demand Response Project (PNDRP).** 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 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), which are both critical components in 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 in time to be used for 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 in time to be used for the development of the next power plan.

**COUN-7** **Perform a regional analysis of operating reserve requirements.** The Council will use the Bonneville analysis of reserve requirements (See BPA-10) 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 8th Power Plan.

**COUN-8** **Participate in and track WECC activities.** The Council should continue to represent the Northwest region at 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 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 implications for the regional need for resources. 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 6c 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 6c 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 6c policy within the next two years.

# 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** **Enhancing BPA end-use load forecasting**. [BPA, 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.

**ANLYS-2** **Improve industrial sales data**. [Council, NEEA, Utilities] Council staff 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 and 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-3** **Improve long-term load forecast for emerging markets**. [Council, Demand Forecast Advisory Committee] Council staff will 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. Council staff will work with utilities and advisory committee members to monitor and forecast loads for these fast growing markets.

**ANLYS-4** **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-5** **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, however data on new and emergent loads, including stand-by, is lacking. Moreover, many of the end-use load shapes used in the Seventh Power 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 costs 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 the end of 2016. Priority should be given for end-use load shapes impacting winter peak and where significant gaps exist.

**ANLYS-6** **Assess the methods of integrating the load forecasts into reliability and system analyses, especially with regard to peak load forecasting** [Council, Resource Adequacy Advisory Committee, Demand Forecasting Advisory Committee] The Resource Adequacy Assessment has used a load forecast method that produces a 3-5 year forward look under historic temperature conditions. This approach differs from the methods used in the power plans, where the long-term forecast is used. Long-term model uses normal temperature profiles. Short-term load forecast method was developed based on requirements for the Resource Adequacy Committee. A different methodology on the expected peak load forecast methodology was developed for the seventh power plan and should be reviewed as part of this process. Reviewing these items should be completed before the next Resource Adequacy Assessment.

# Conservation

**ANLYS-7** **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. However, these activities lack the coordination that could improve usefulness, reduce duplication, provide better access to existing data, and identify significant research gaps. The research coordination forum should 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 similar to Bonneville's Northwest Energy Efficiency Technology Roadmap Portfolio and a work plan to identify tasks and implementers. The roadmap and work plan should be completed by mid-2018.

**ANLYS-8** **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 have these benefits. Several such measures identified in the Seventh Power 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 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-9** **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 Power 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 Seventh Power Plan's baselines. If the baseline is not aligned with the Power 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-10 Increase recognition of non-energy benefits.** [RTF, States] Although difficult to quantify, non-energy benefits due to efficiency improvements (such as water savings and health benefits due to reduction in wood smoke emissions1) may be significant and thus justify investment, regardless of whether the measures are cost-effective on energy benefits and costs alone. The region should conduct research to identify and quantify non-energy benefits, and recognize quantification may not always be feasible with available resources. States should consider such benefits when setting cost-effectiveness limits. 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, the RTF should either quantify or include model language to note their impact.

**ANLYS-11 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 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 end of 2017.

## Generation

**ANLYS-12 Planning coordination and information outreach.** 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 including the Demand Forecast Advisory Committee, Natural Gas Advisory Committee, Conservation Resources Advisory Committee and Generating Resources Advisory Committee for purposes of sharing information, tools, and approaches to resource planning.

**ANLYS-13 Re-develop the revenue requirements finance model – MicroFin.** [Council Staff, Bonneville, User Group] Council staff, in coordination with BPA 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 staff 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

[1] See Chapters 12 and 19 for more information

in the development of the Eighth Power Plan. Council staff 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-14 Update generating resource datasets and models.** [Council Staff] The Council staff 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 Power Plan, with completion in time for the Eighth Power 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-15 Monitor and track progress on the emerging technologies that hold potential in the future Pacific Northwest power system.** [Council Staff, GRAC] Council staff should continue to monitor on an ongoing basis the emerging technologies identified in the Seventh Power 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[2]
    - Battery storage
    - Other

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

**ANLYS-16 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, GRAC subgroup of experts] The Council will 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-17 Research and develop a white paper on the value of energy storage to the future power system.** [Council Staff, GRAC subgroup of Storage Experts] Council staff should convene a group of subject matter experts 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

[2] 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.

reserves in the regional power system. Council staff 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 Power 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-18 Track utility scale solar photovoltaic costs, performance and technology trends in the Pacific Northwest, and update cost estimates.** [Council Staff, GRAC] Council staff 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 Power 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-19 Track natural gas-fired technology costs and performance, and update as necessary, particularly around combined cycle combustion turbine (CCCT) and reciprocating engine technologies.** [Council Staff, GRAC] Council staff should continue to monitor on an ongoing basis 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-20 Monitor new natural gas developments in the region and gauge the potential impact on the regional power system.** [Council Staff, GRAC, PNUCC] Council staff 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. A PNUCC subcommittee 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. PNUCC is following similar issues, and may offer a collaborative opportunity. 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-21 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 Staff, GRAC] Council staff 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-22 Review analytical methods**. [Council, BPA] 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 on how the Bonneville Administrator can best meet the agency's obligations and 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 because these currently pressing issues will need to be more formally addressed in future power plans.

**ANLYS-23 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 Council, who will decide on an appropriate approach given the limited funding available. This redevelopment should be completed and tested in time to be used to develop the next power plan.

**ANLYS-24** **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. Council staff will make recommendations to the Council. Any changes in the GENESYS model should be fully incorporated and tested in time to develop the next power plan.

## Transmission

**ANLYS-25** **Coordinate with regional transmission planners.** 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-26** **Transmission Expansion Planning Policy Committee (TEPPC).** 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 the effects of transmission development on the environment in general and on wildlife in particular.** [Council Staff, State Fish and Wildlife Agencies, Indian Tribes, State Energy Siting Agencies, Transmission Providers, Utilities, Bonneville] The region's fish and wildlife agencies and Indian tribes have expressed significant concern about especially the cumulative effects of the region's transmission system on the environment in general and on wildlife and wildlife habitat in particular, especially given the recent expansion of the transmission system to support gas-fired and renewable energy development. Council staff should work with representatives of the state fish and wildlife agencies and Indian tribes along with the state energy siting entities, transmission providers, utilities, Bonneville, and others to gain a better understanding before the next power plan of the nature and extent of both the 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 transmission effects and the efficacy of those actions; and what gaps exist, if any, in terms of unaddressed cumulative impacts to the environment and wildlife from transmission development.