CHAPTER 3: RESOURCE STRATEGY

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KEY FINDINGS

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

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

A RESOURCE STRATEGY FOR THE REGION

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

Summary

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

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

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

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

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

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

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

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

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

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

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

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

SCENARIO ANALYSIS – THE BASIS OF THE RESOURCE STRATEGY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

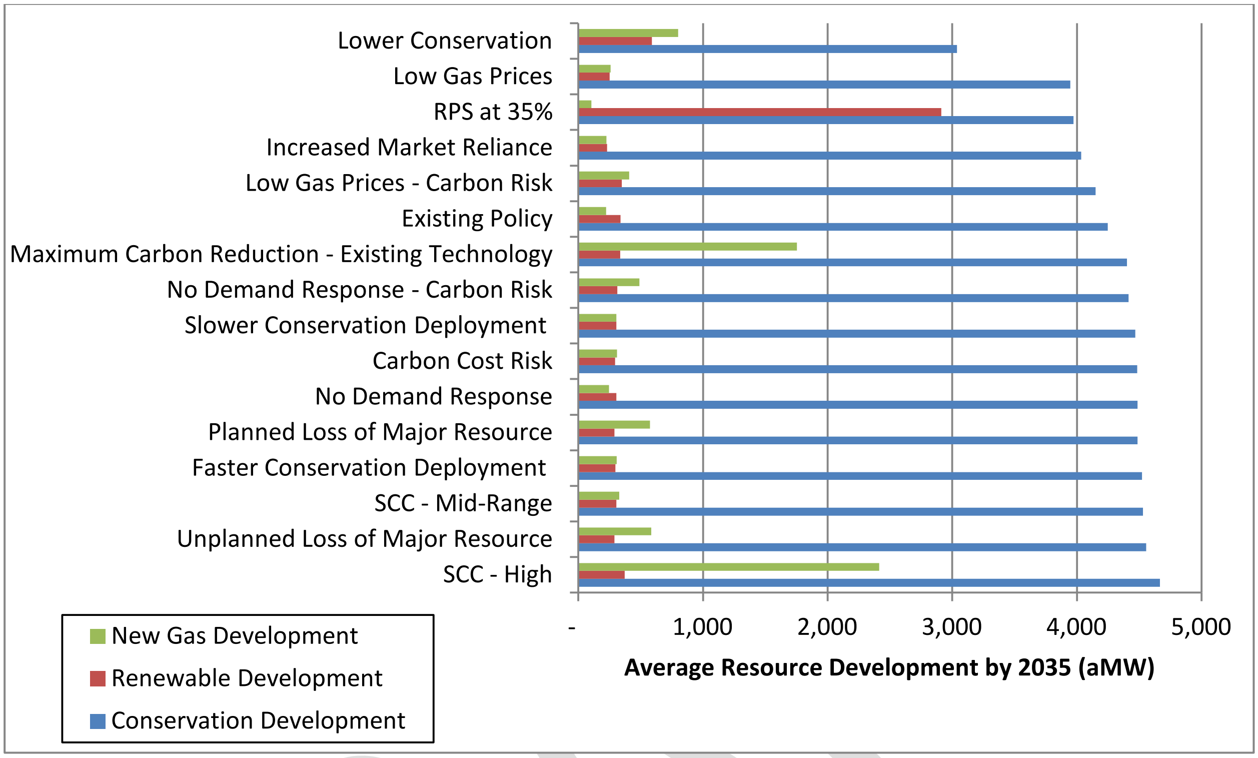
THE RESOURCE STRATEGY

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

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

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

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



Energy Efficiency Resources

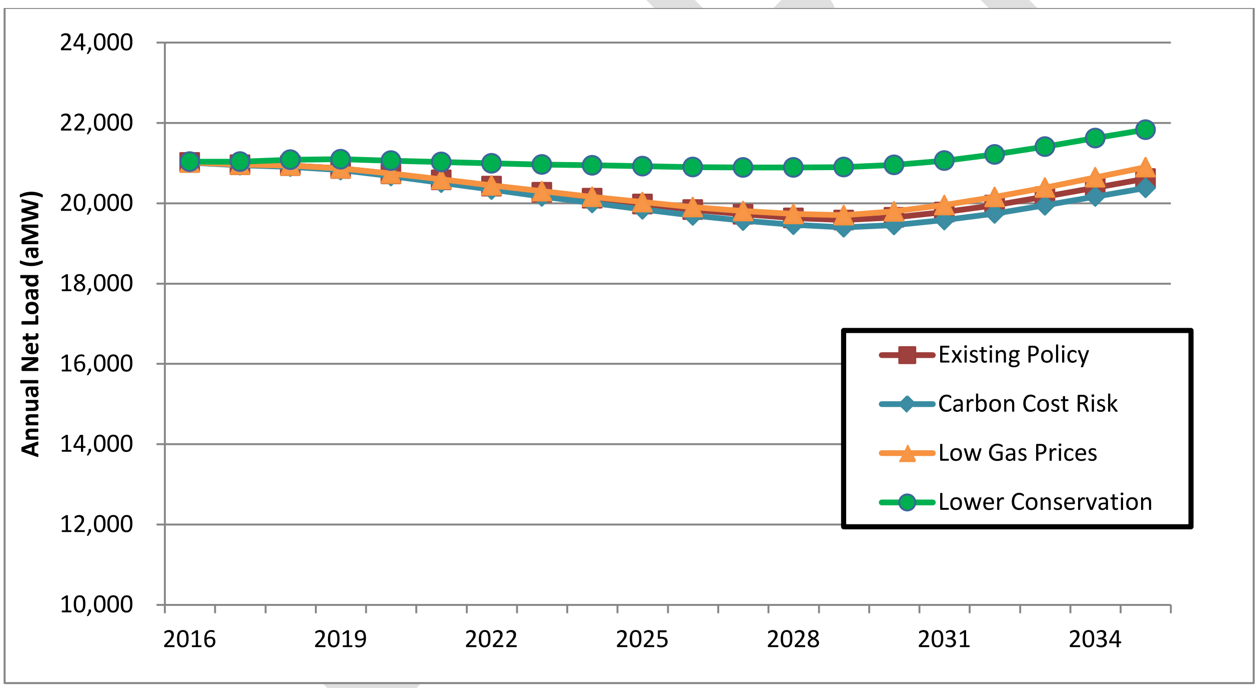
Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,900 average megawatts of conservation. This achievement makes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

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

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

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

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



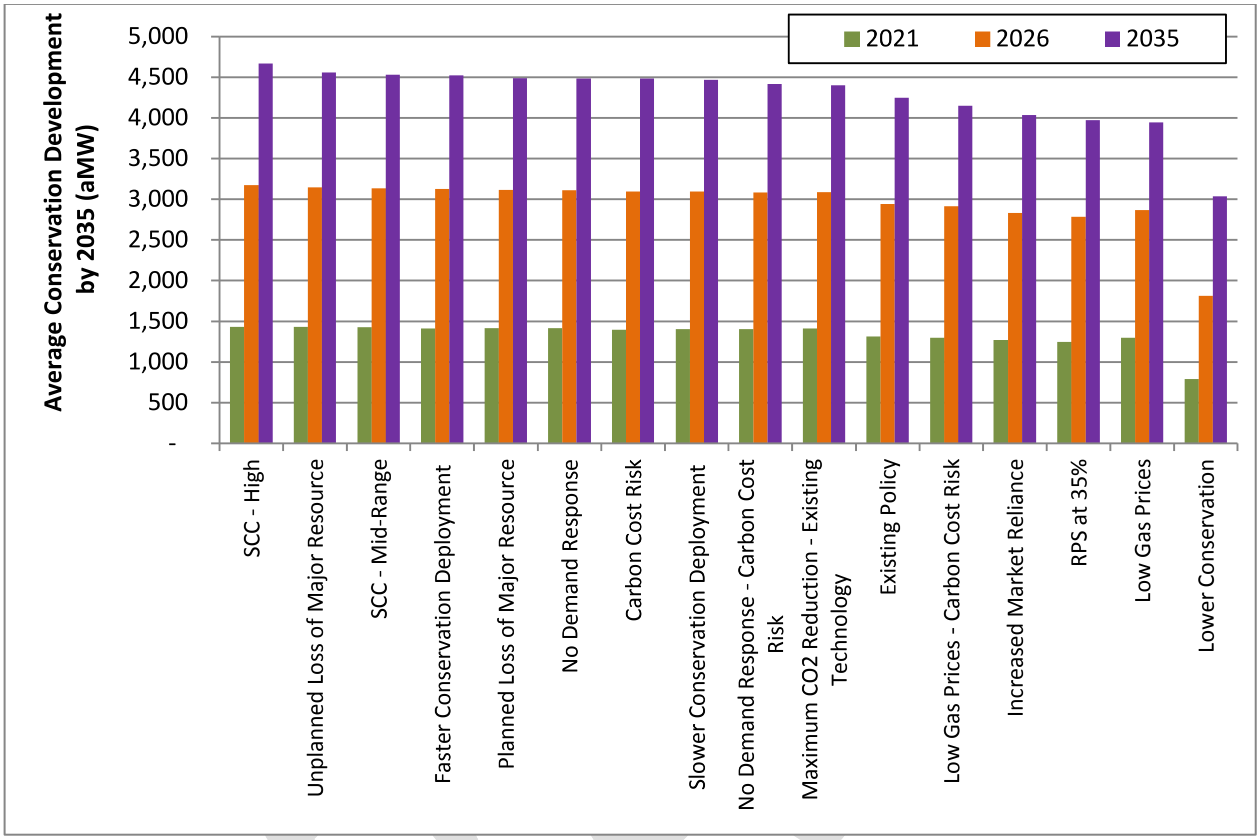
[2] This is the average real levelized cost of all conservation measures acquired in the resource strategy, excluding a cost-offset that is expected to occur as a result of lower load growth which defers the need to expand distribution and transmission systems. In evaluating conservation's cost-effectiveness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

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

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

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

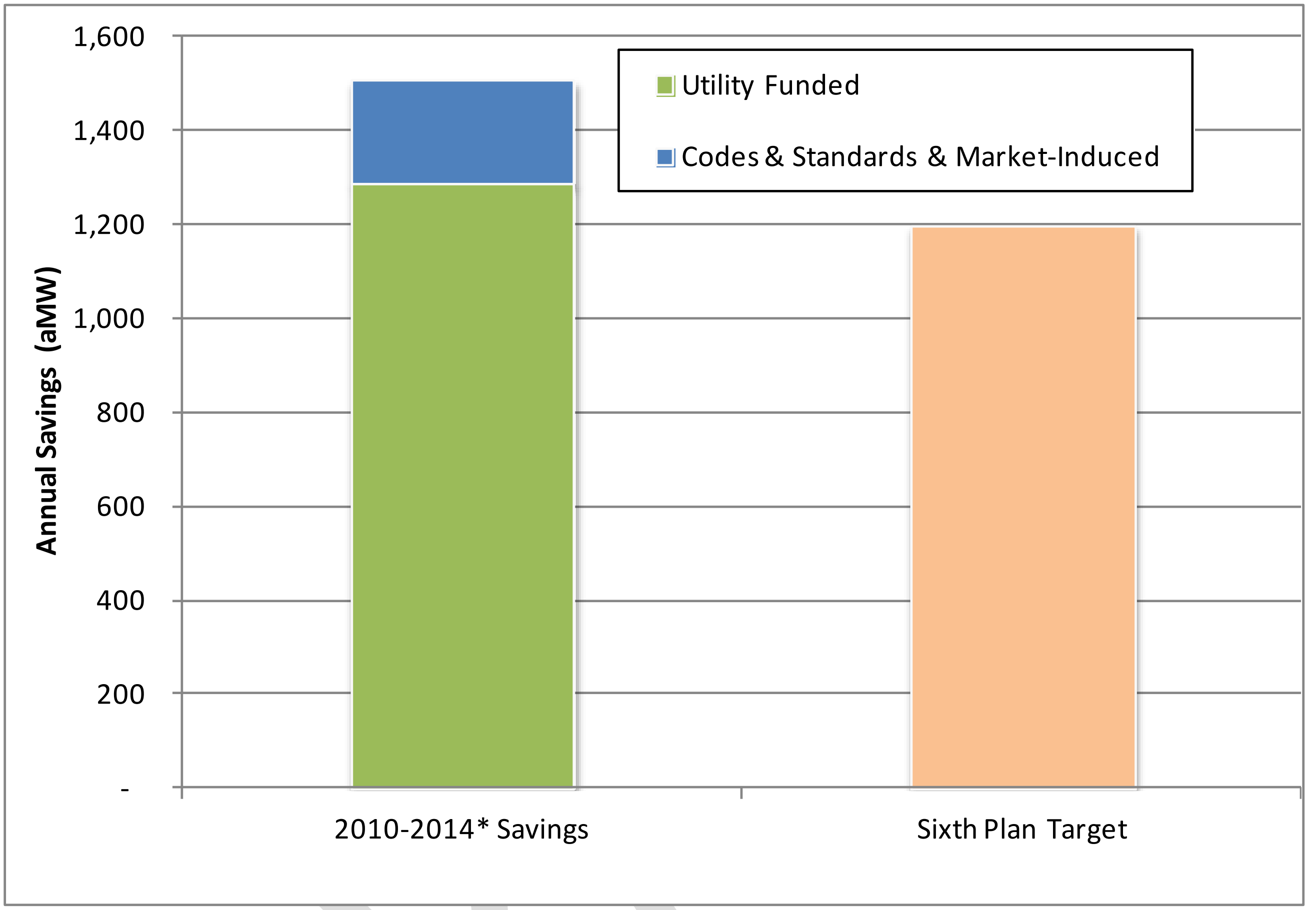
Figure 3 - 3: Amount of Cost-Effective Conservation Resources Developed Under Different Scenarios



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

The amount of efficiency included in the Seventh Power Plan is comparable to that identified in the Council's Sixth Power Plan; even though the 20-year goal is lower (4,500 aMW vs. 5,800 aMW). To a large extent, this decrease is the result of regional conservation program achievements since the Sixth Plan was adopted in 2010 as well as significant savings that will be realized as a result of federal standards and state codes enacted since the Sixth Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 (projected) compared to the Sixth Plan's conservation goal for the same period. In addition, Figure 3 - 4 shows the savings achieved from the combined impact of federal and state appliance and equipment standards, state building codes, and market-induced savings. In aggregate, actual achievements from 2010 through 2014 were nearly 1500 average megawatts, exceeding the Sixth Plan's five year goal of 1200 average megawatts by 25 percent.

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



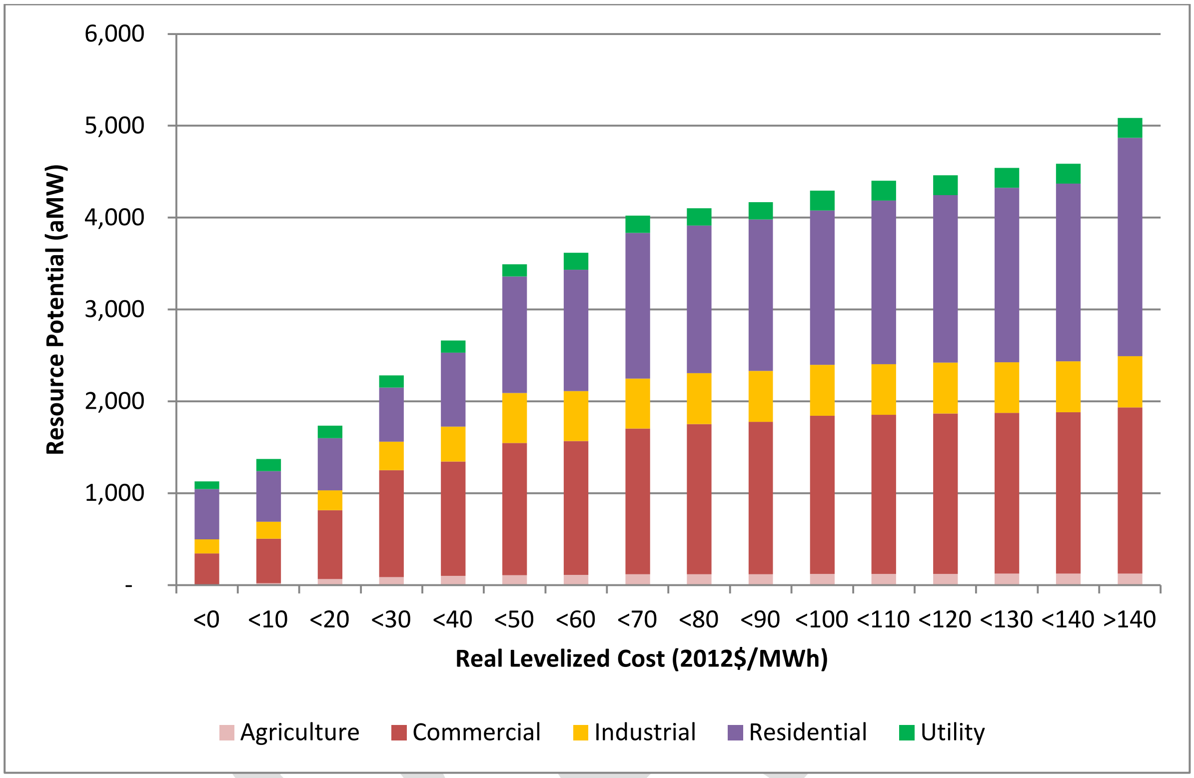
* 2014 savings are preliminary

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

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

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

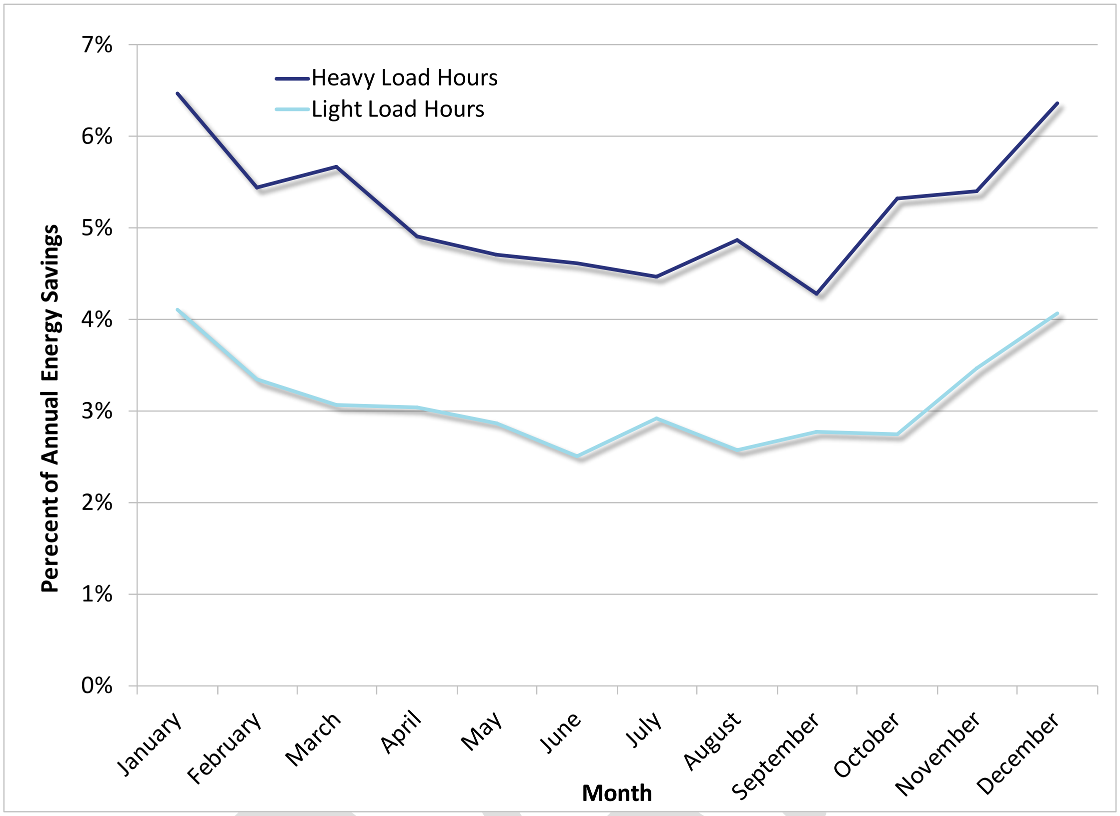
Figure 3 - 5: Efficiency Potential by Sector and Levelized Cost by 2035



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

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

Figure 3 - 6: Monthly Shape of 2035 Efficiency Savings



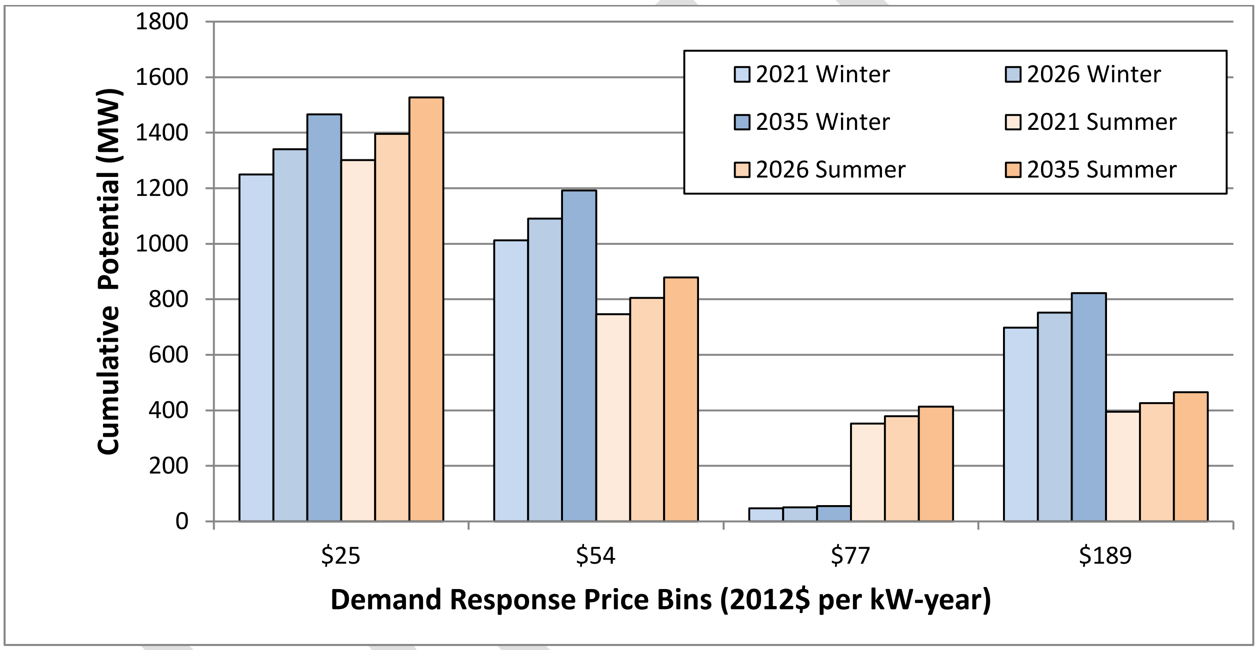
Demand Response

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

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

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

Figure 3 - 7: Demand Response Resource Supply Curve



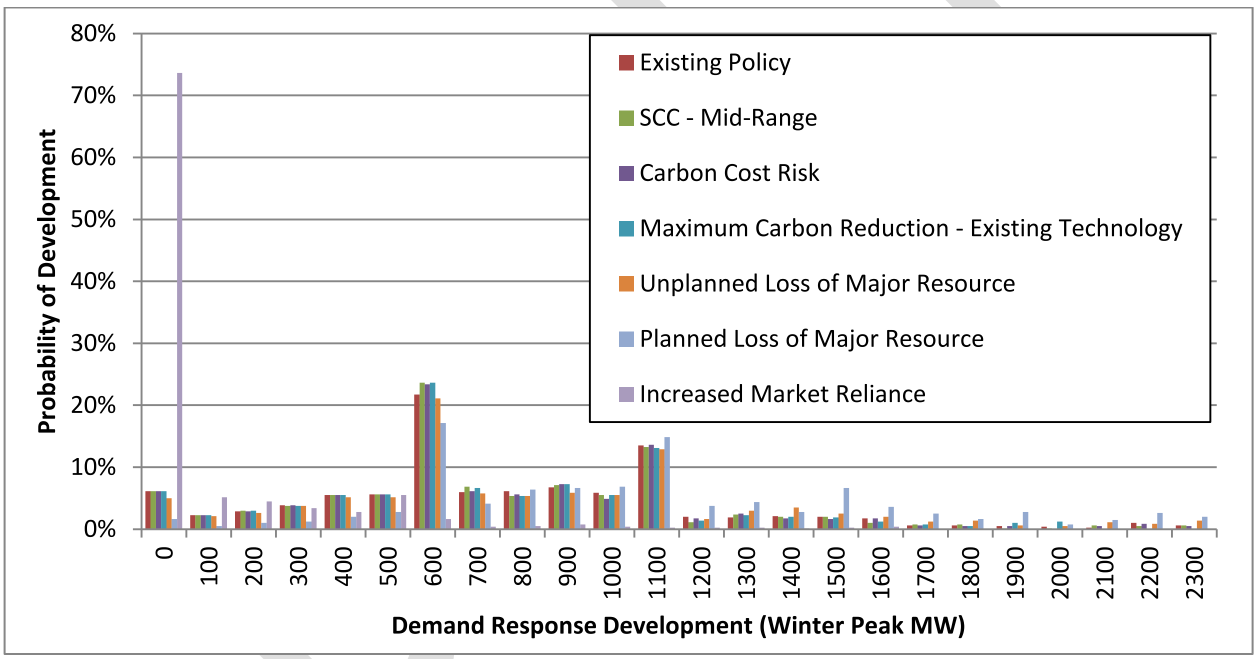
The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources make them particularly valuable because the need for peaking capacity resources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

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

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

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

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



Renewable Generation

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

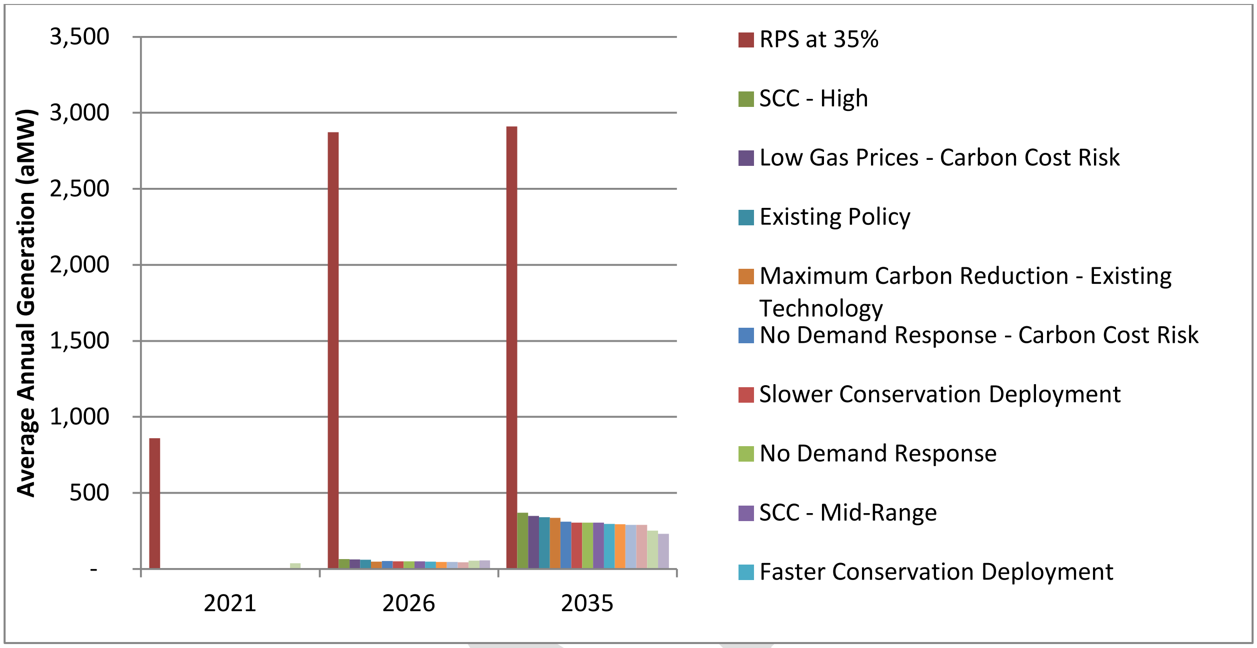
It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

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

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

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

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



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

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

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

Natural Gas-Fired Generation

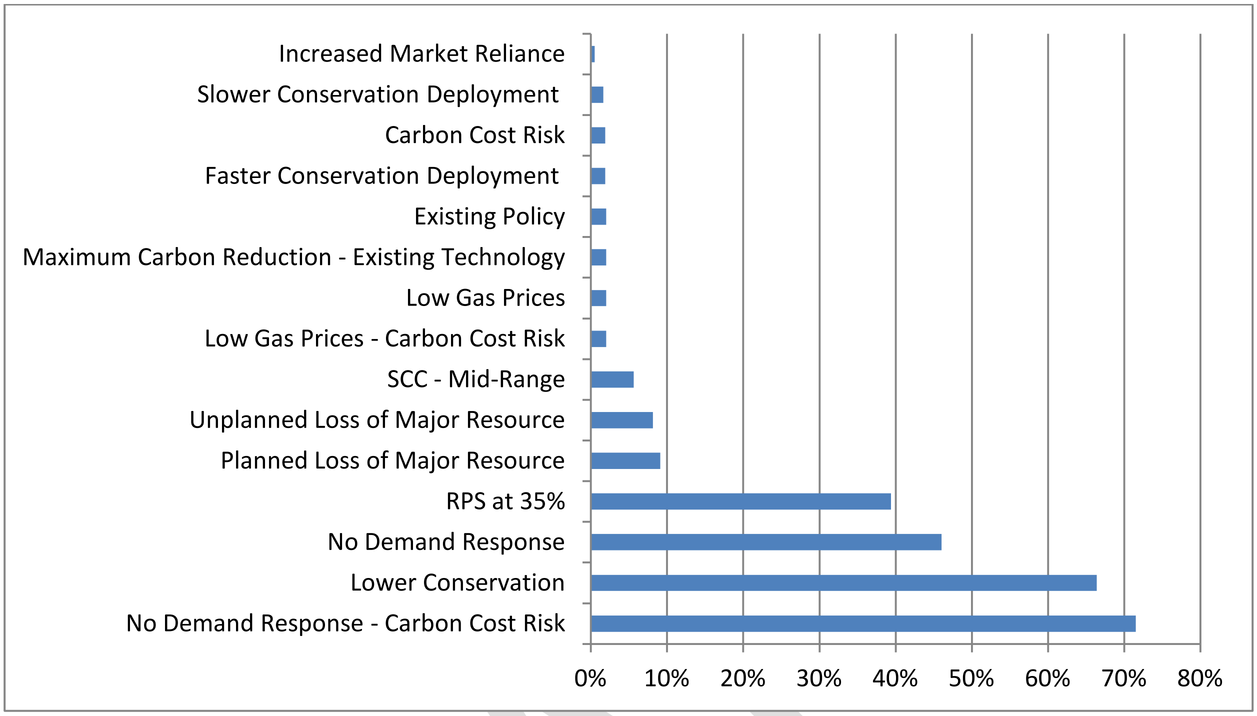
Natural gas is the fourth major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh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

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

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

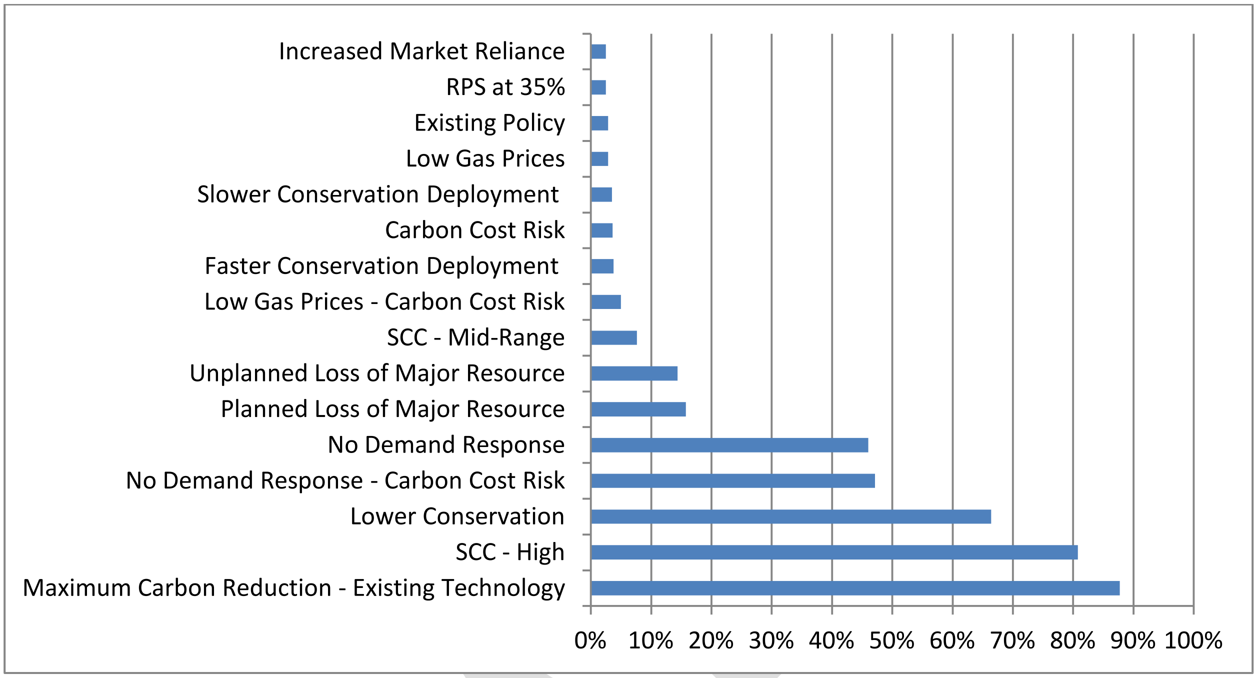
By 2026, Figure 3 - 11 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 80 percent in the **SCC-High** and **Maximum Carbon Reduction – Existing Technology** scenarios. This occurs because under both of these scenarios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

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



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

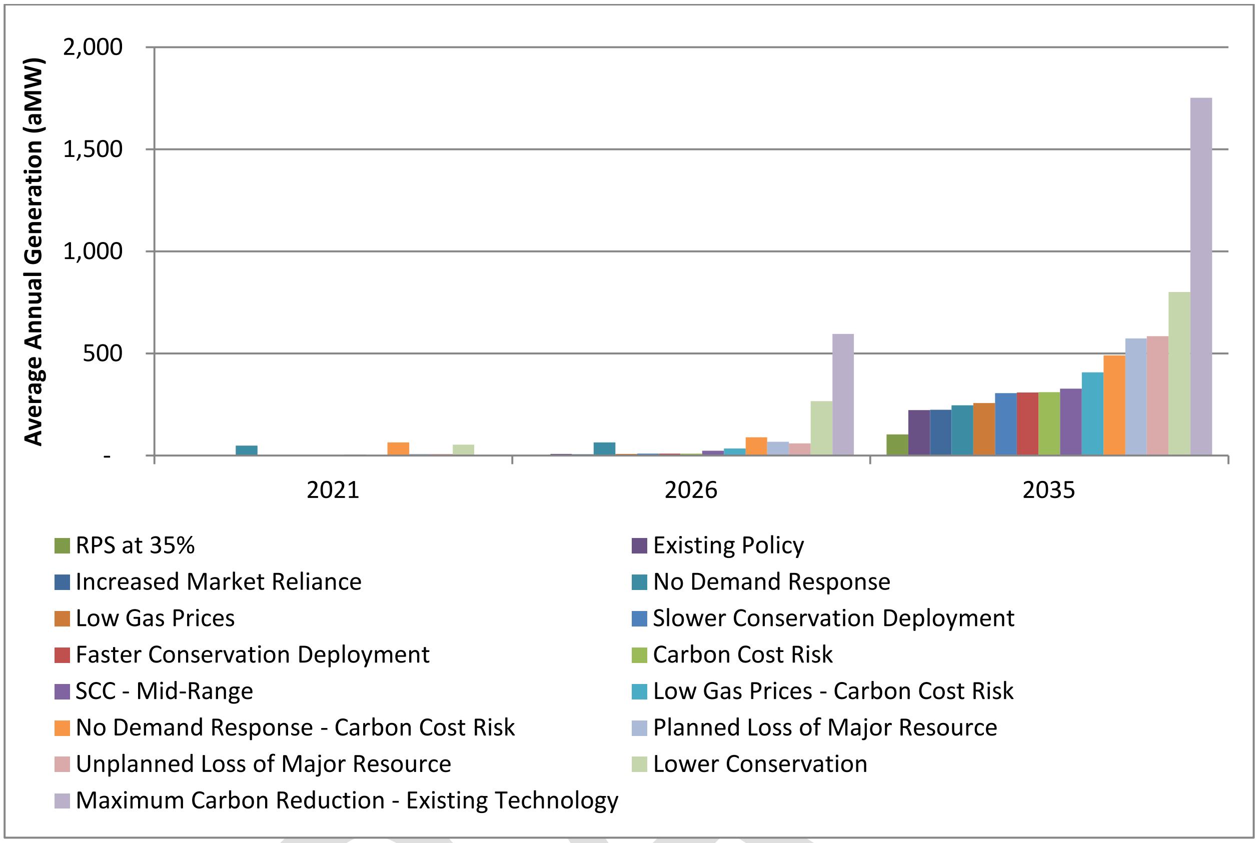
Figure 3 - 11: Probability of New Natural Gas-Fired Resource Development by 2026



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

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

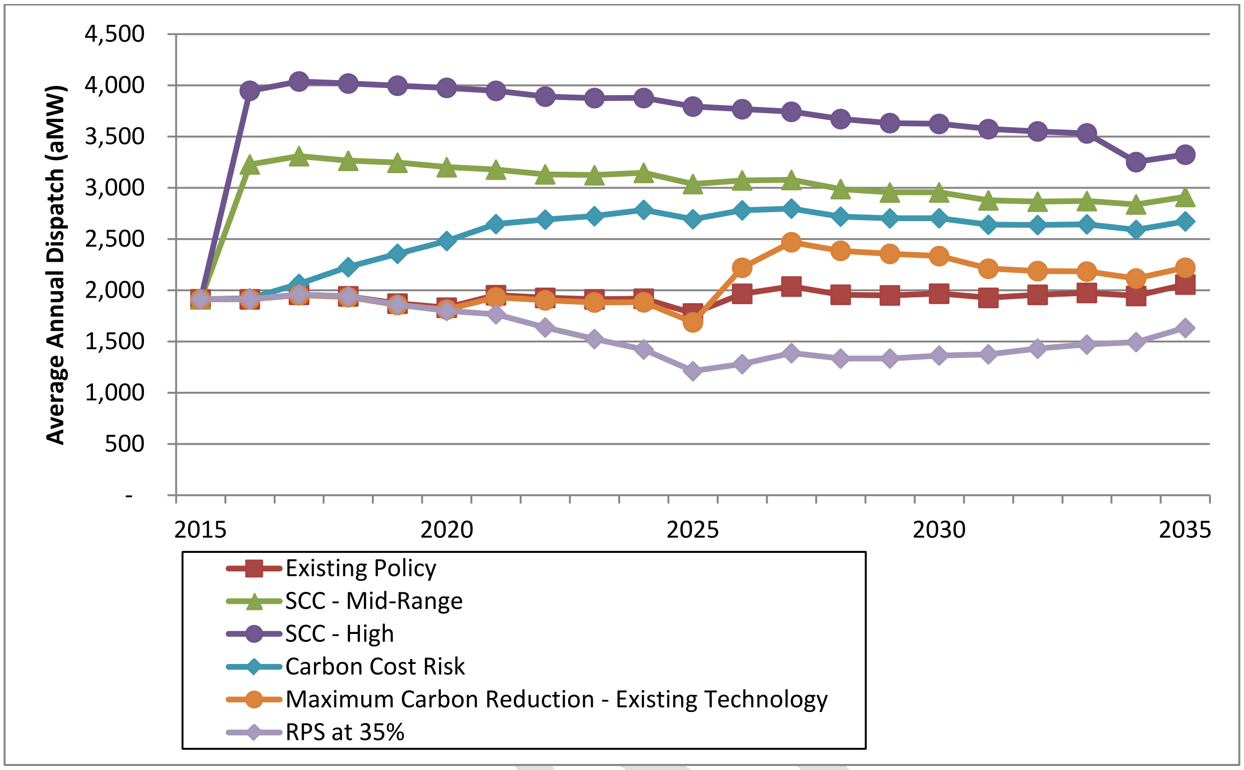
Figure 3 - 12: Average New Natural Gas-Fired Resource Development



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

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

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



Carbon Policies

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

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

Regional Resource Utilization

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

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

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

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

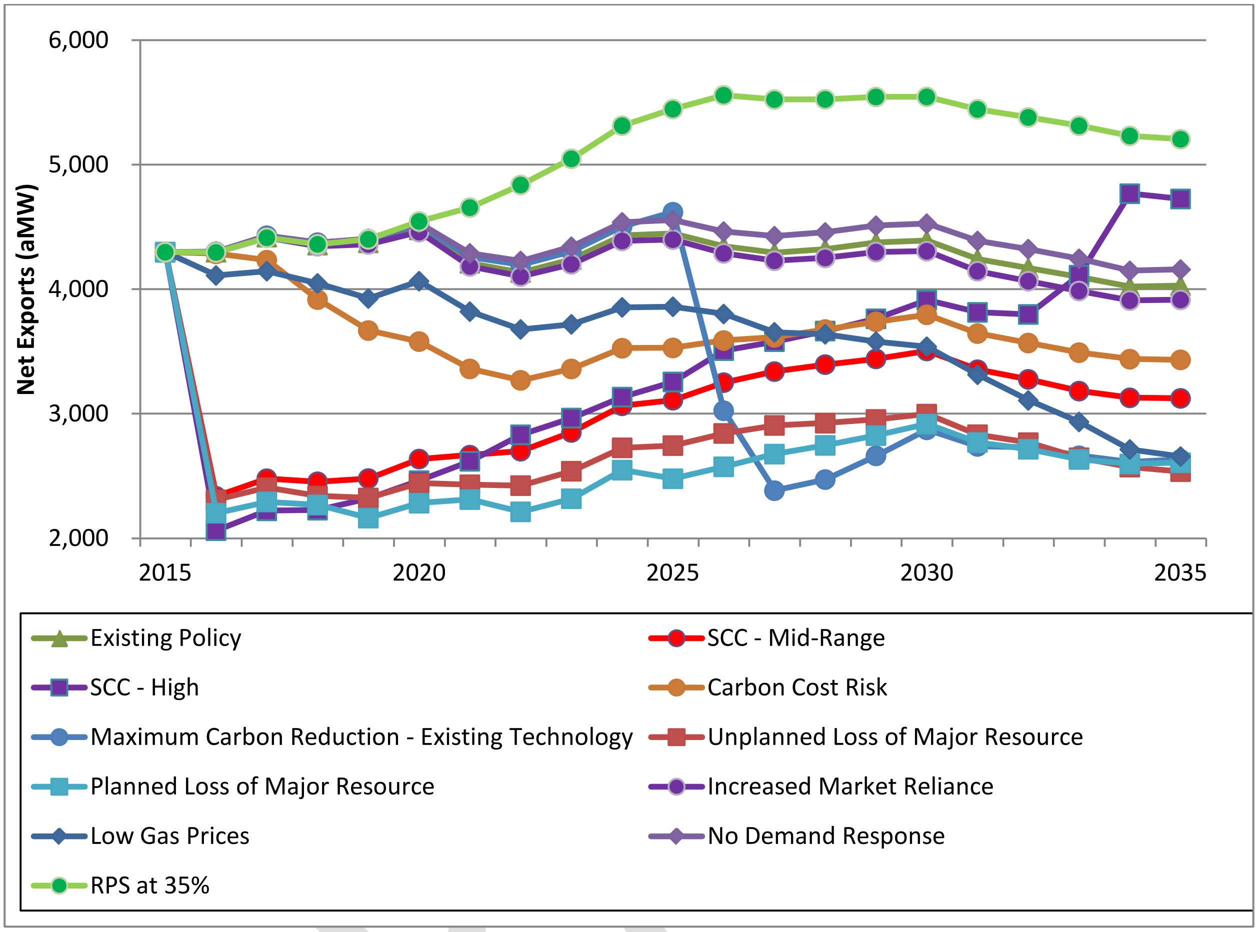
In contrast, under the two the scenarios which assume that carbon dioxide damage costs are imposed in 2016 (e.g. **SCC-Mid-Range** and **SCC-High**), net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon dioxide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

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

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

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

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



Develop Long-Term Resource Alternatives

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

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

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

Adaptive Management

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

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

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

CARBON DIOXIDE EMISSIONS

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

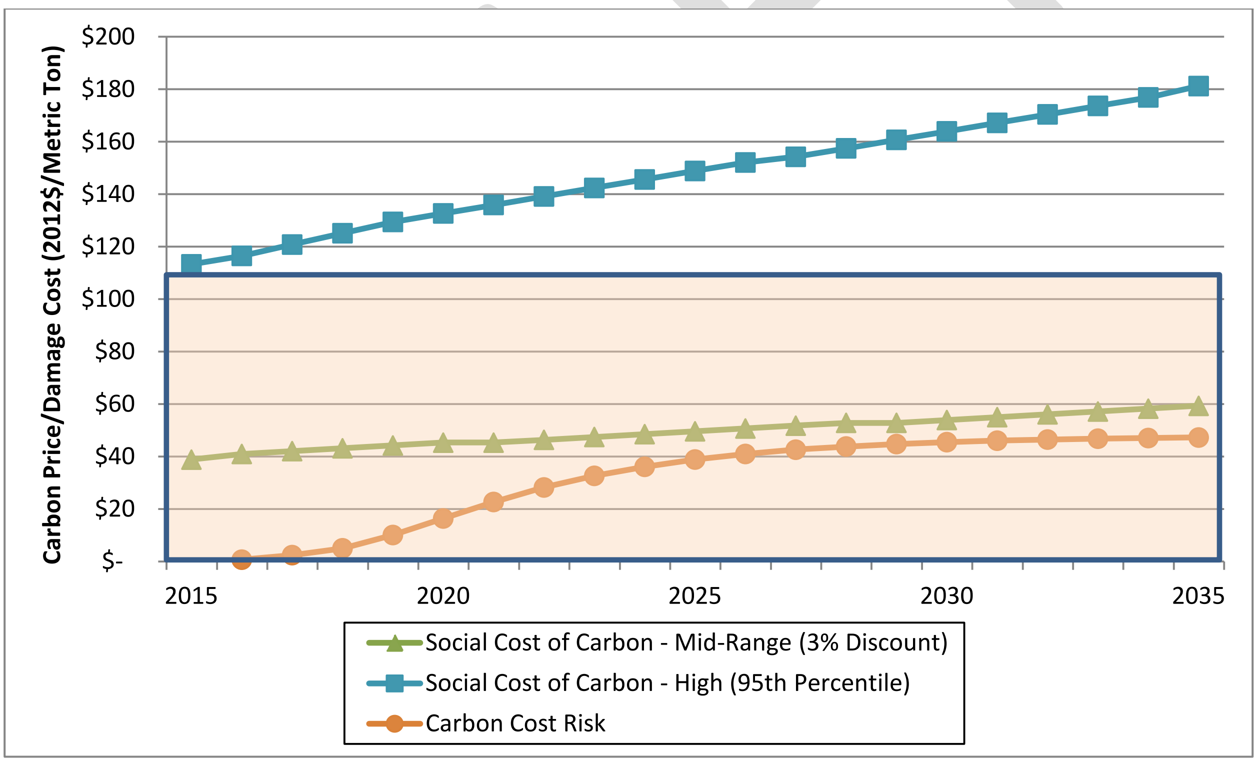
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide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

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

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

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

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



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

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

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

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

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

Table 3 - 1 shows the average system costs and carbon dioxide emissions for the seven scenarios and sensitivity studies conducted to specifically evaluate carbon dioxide emissions reductions policies (and economic risks) for the development of the Seventh Power Plan. This table shows the average net present value system cost for the least cost resource strategy for each scenario, both with and without carbon dioxide revenues. It also shows the average carbon dioxide emissions

projected for the generation that serves the region in 2035. For comparison purposes, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 55 million metric tons from 2000 through 2012.

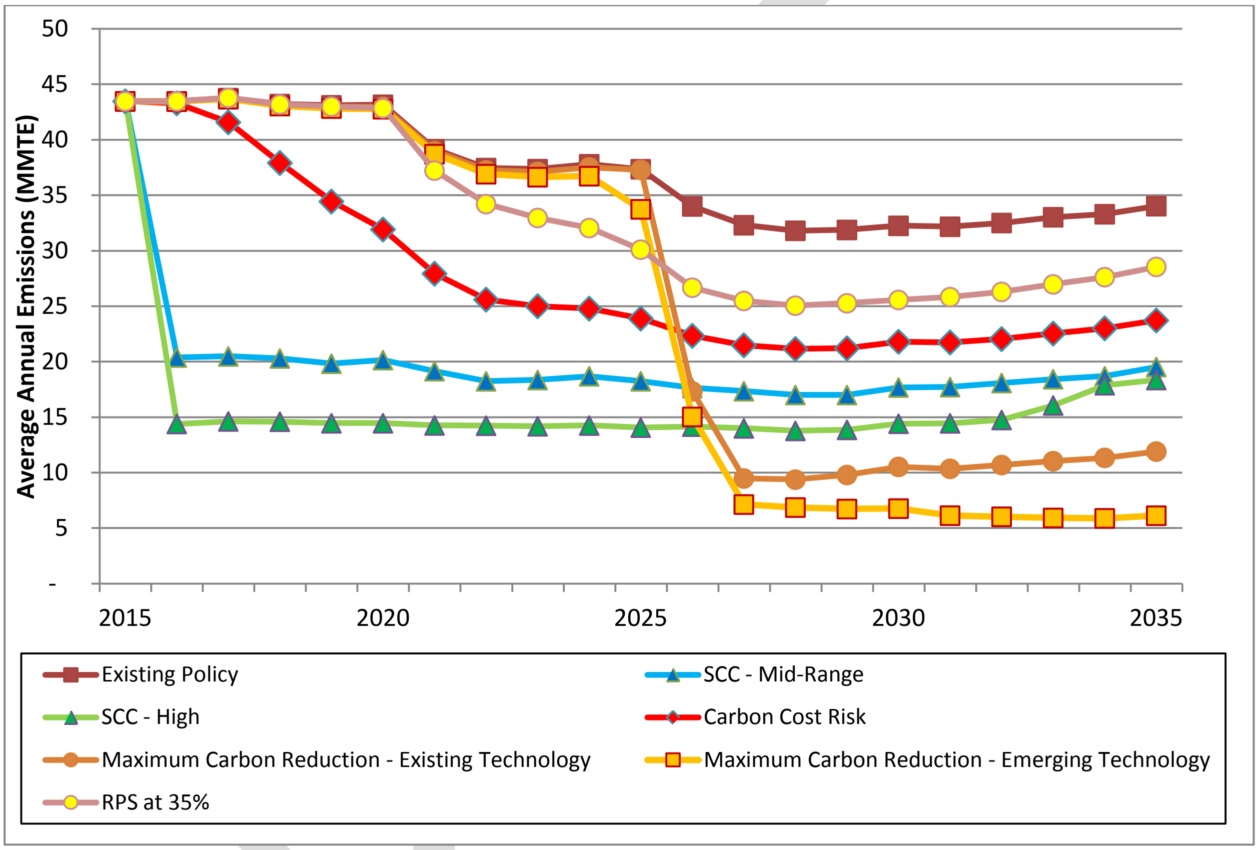
Table 3 - 1: Average System Costs and PNW Power System Carbon Dioxide Emissions by Scenario

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

Table 3 - 1 shows the **Existing Policy** scenario which assumed no additional carbon dioxide emissions reductions policies beyond those in place prior to the issuance of the Environmental Protection Agency's Clean Air Act 111(b) and 111(d) regulations results in carbon dioxide emissions in 2035 of 34 million metric tons. The direct cost of this resource strategy is $88 billion (2012$). Three scenarios, the **SCC-Medium, SCC-High** and **Carbon Cost Risk** scenarios produce similar reductions in carbon dioxide emissions at similar costs. All three of these scenario result in carbon dioxide emissions of between 18 – 24 million metric tons in 2035 and have a direct cost of $1 - $2 billion more than the **Existing Policy** scenario's least cost resource strategy. The least cost resource strategy in the **Maximum Carbon Reduction - Existing Technology** scenario reduces 2035 carbon dioxide emissions to 12 million metric tons, or to about one-third that of the **Existing Policy** scenario. However, the estimated direct cost of this resource strategy is $20 billion, significantly higher than the **Existing Policy** scenario's least cost resource strategy. The **RPS at 35 percent** scenario's least cost resource strategy produces the least reduction in 2035 carbon dioxide emissions. Yet, this policy has the highest direct cost of all the options considered, at $34 billion more than the **Existing Policy** scenario's resource strategy. The **Maximum Carbon Reduction - Emerging Technology** scenario reduces 2035 carbon dioxide emissions to 6 million metric tons, roughly half the emissions of the **Maximum Carbon Reduction - Existing Technology** scenario. As stated above, no costs were calculated for this scenario, due to the speculative nature of the technologies considered.

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

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



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

Table 3 - 2 shows cumulative emission reductions from 2016 through 2035 for each of the carbon dioxide reduction policy scenarios compared to the **Existing Policy** scenario. It also shows the average system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide

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

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

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

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

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon dioxide emissions will continue beyond 2035, as will their carbon dioxide emissions impacts. These “end-effects” could alter the perceived relative cost-efficiency of carbon dioxide reduction policy options shown in Table 3 - 2. For example, over a longer period of time the cumulative emissions reductions from the **Maximum Carbon Reduction –**

Existing Technology scenario could exceed those from the **SCC-Mid-Range** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 8 MMTE per year lower emissions. In this instance, if the difference in emissions rates for these two scenarios were to remain the same for an additional 20 years, then their cumulative emissions reductions over 40 years would be nearly identical. Since it is impossible to forecast these "end effects," readers should consider the scenario modeling results shown in Table 3 - 2 as directional in nature, rather than precise forecast of either emissions reductions or the cost to achieve them.

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

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

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning, development the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments the EPA issued it final Clean Power Plan (CPP) rules. The "111(d) rule," referred to by the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants, has a goal of reducing national power plant carbon dioxide emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. EPA also issued the final rule under the Clean Air Act section 111(b) for new power plants and the proposed federal plan and model rules that would combine the two emissions limits.

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

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

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

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

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

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically

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

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

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

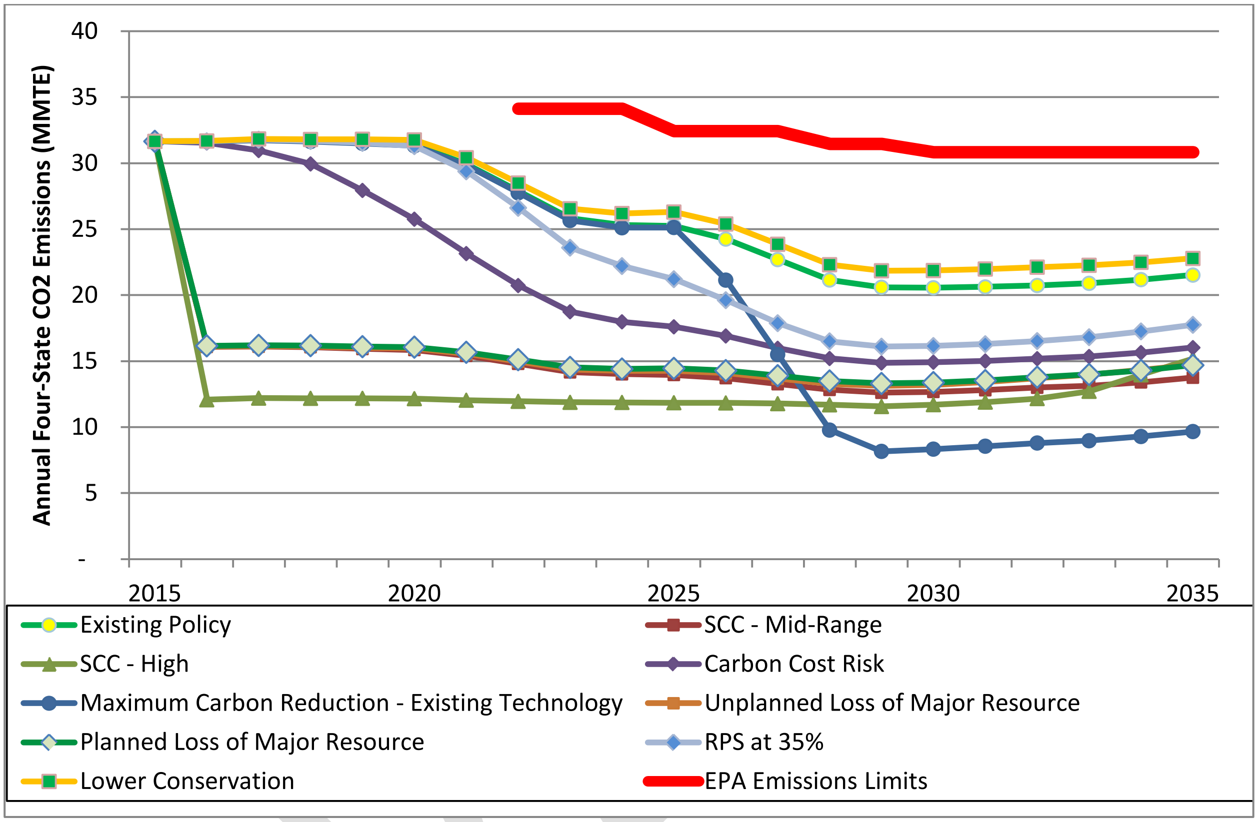
Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from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

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

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

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

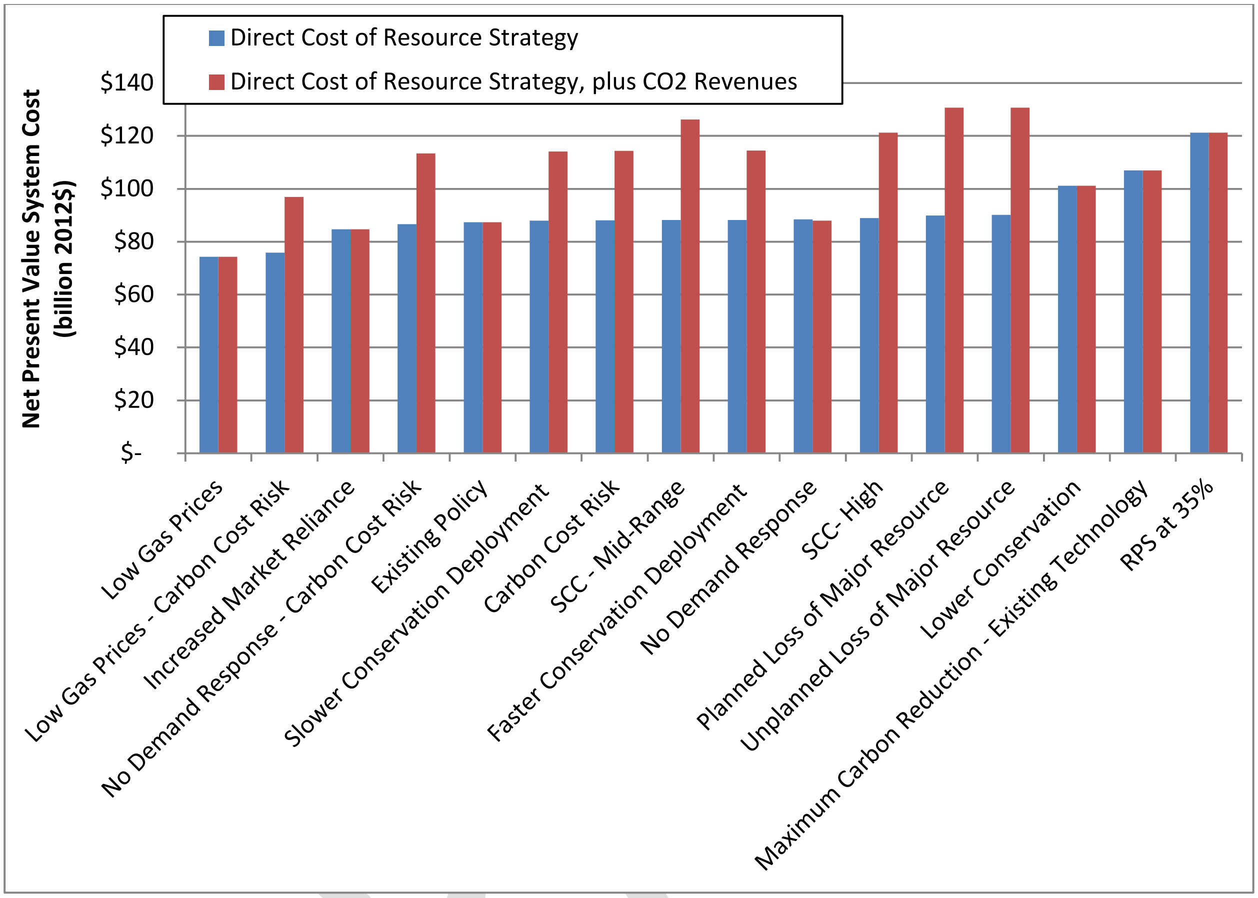
Figure 3 - 17: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



RESOURCE STRATEGY COST AND REVENUE IMPACTS

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

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



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

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

The **Maximum Carbon Reduction – Existing Technology** scenario differs from the others because it assumes that all of the coal plants that serve the region are retired as well as existing gas generation with heat rates over 8,500 Btu/kilowatt-hour. As a result, the present value system cost is significantly increased by the capital investment needed in replacement resources, largely new combined-cycle combustion turbines. The least cost resource strategy under the **Lower Conservation** scenario develops about 1200 average megawatts less energy savings and 2900 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $14 billion higher because it must substitute more expensive generating resources to meet the region’s needs for both capacity and energy.

Under the **Renewable Portfolio Standard at 35 percent** scenario, the increase in average present value system cost stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs.

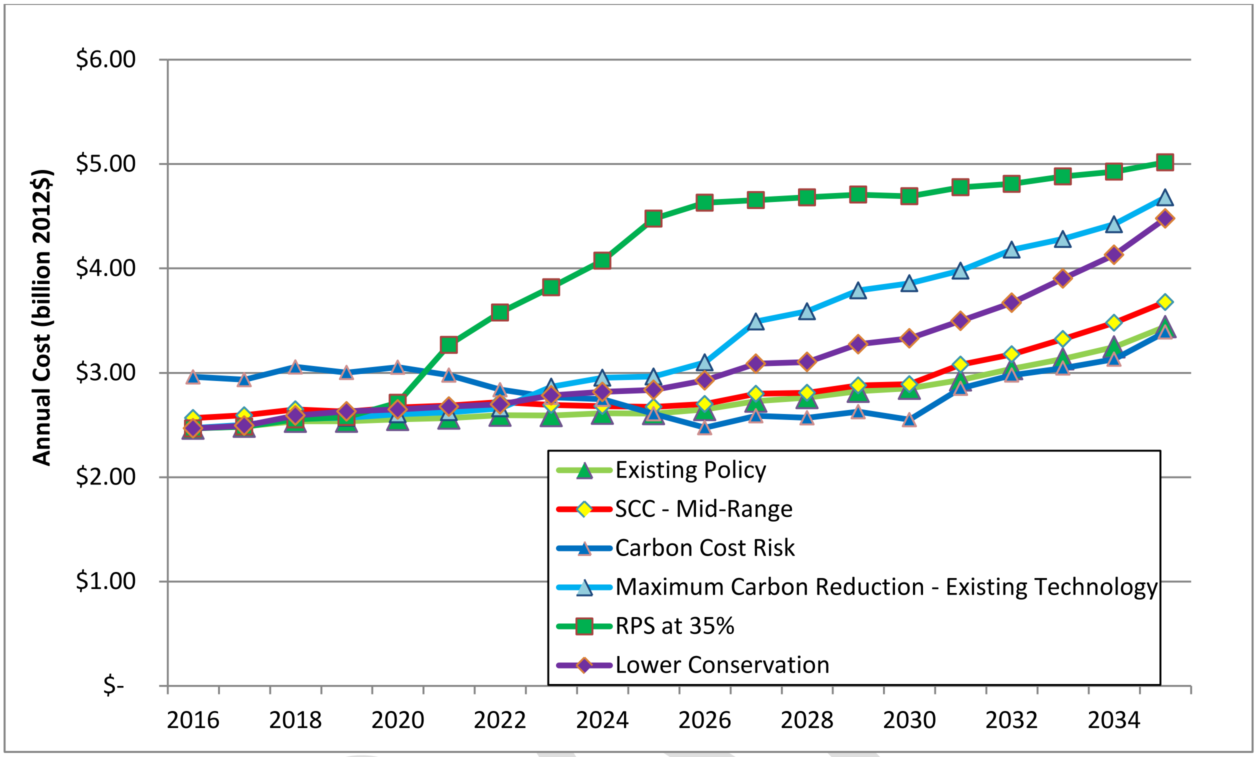
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

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

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

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

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

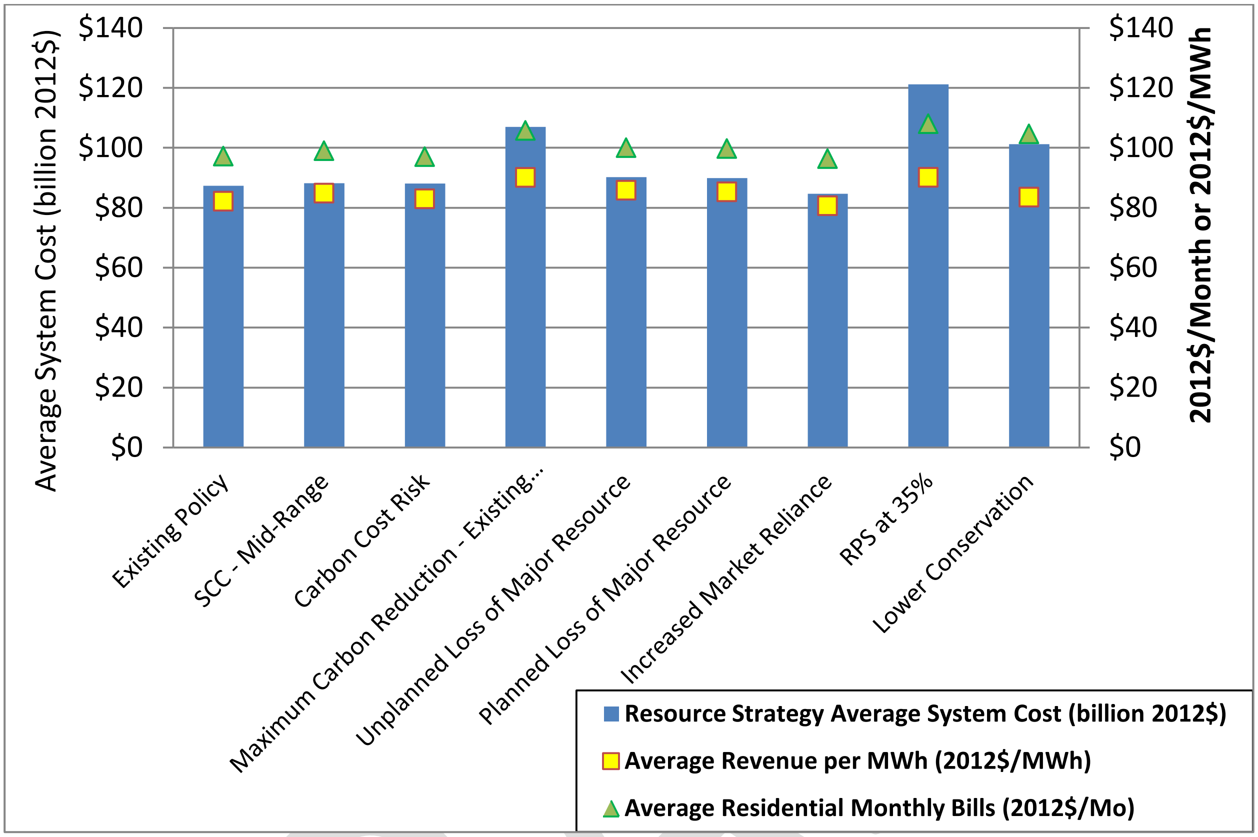


A review of Figure 3 - 19 shows that the **Carbon Cost Risk** resource strategy has a slightly lower annual cost post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35 percent**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

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

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

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



As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the lower-conservation scenario. The **Lower Conservation** scenario has an average system cost of $102 billion, compared to the **Existing Policy** resource strategy's $88 billion. Even with nearly a $14 billion higher average system cost the **Lower Conservation** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirement per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy** scenario and $84 per megawatt-hour for the **Lower Conservation** scenario. However, **the Lower Conservation** scenario's average monthly bill is about $105, about $6 per month higher than **the Existing Policy** scenario's average monthly bill of $99. This illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 3 - 21 illustrates how the greater efficiency improvements lower average electricity bills.

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