CHAPTER 15: ANALYSIS OF ALTERNATIVE RESOURCE STRATEGIES

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KEY FINDINGS

Developing low cost, low risk resource strategies for the power system in a robust manner requires stress testing alternative resource mixes over a large range of potential future conditions. Those resource strategies that exhibit low cost and low risk across a wide range of future conditions are the most desirable. In addition, if components of the resource strategy that are within the control of utilities are amenable to adapting to future conditions such strategies are also more desirable. For example, if the success of a resource strategy relies on low natural gas prices, it is less desirable than one that relies on increased deployment of energy efficiency or demand response. Future natural gas prices are beyond the control of utilities, while development of energy efficiency or demand response resources is within utility control. Making good decisions with due consideration for uncertainty requires understanding the dynamic between the decisions that are within the realm of a utility planner and the uncertainty beyond their control. This chapter describes the approach used to model this dynamic and estimate future system costs under a wide range of potential future conditions.

UNCERTAINTY ABOUT THE FUTURE

The future is uncertain. Therefore, the ultimate cost and risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the potential cost and risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or risk, and to bracket the range of those uncertainties. The primary uncertainties examined by the Council's Regional Portfolio Model (RPM) are demand for electricity, generation from the hydroelectric system, market prices for both electricity and natural gas, and carbon dioxide (CO2) policy. Each of these is discussed below.

Demand for Electricity

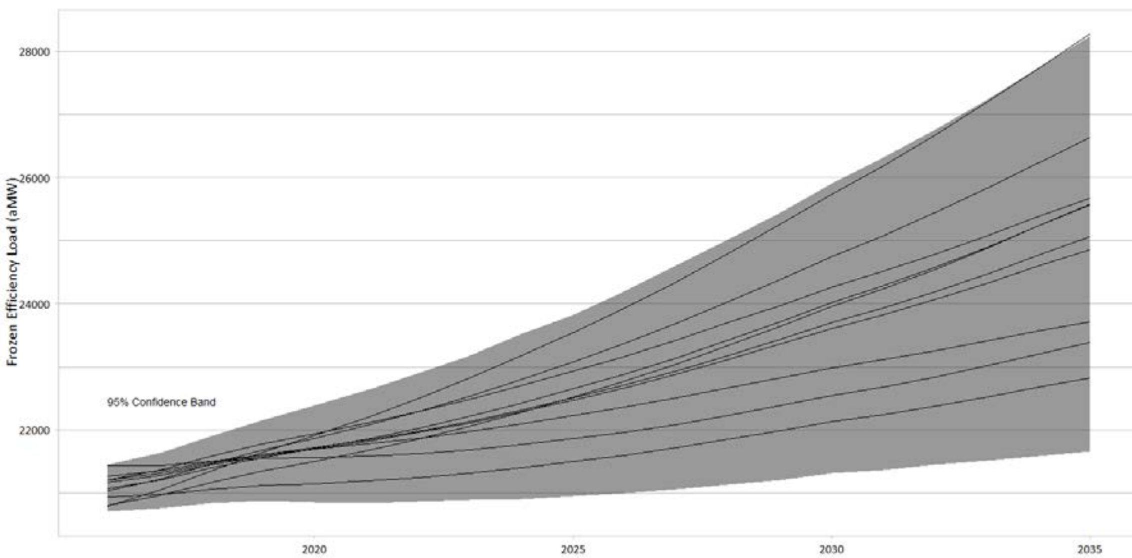
One of the principal uncertainties faced by the region is how much electricity will be needed in the future. Since future economic conditions could vary significantly, the Council develops a range forecast for those variables, such as population and employment growth that drive the demand for electricity. Chapter 7 and Appendix E describe the derivation of the Council electric load growth forecast range (i.e., low, medium and high). Because conservation is treated as a potential resource when developing a resource strategy, the forecast of future electricity loads intentionally exclude any conservation savings, except those from codes and standards that have already been enacted. This forecast is, therefore, referred to as a "frozen efficiency load forecast."

To analyze the impact of the uncertainty surrounding future demand for electricity on alternative resource strategies, the "frozen efficiency" load forecast is translated into 800 "potential futures."[1]

[1] A discussion of how these futures are developed appears in Appendix L which describes the Regional Portfolio Model (RPM).

To represent future business cycles and overall economic growth patterns, each of these 800 potential futures has a unique load growth rate and pattern. Figure 15 - 1 shows a sample of the 800 future load paths across the 20-year study horizon that were considered when testing alternative resource strategies.

Figure 15 - 1: Example of forecast potential future load for electricity



Hydroelectric Generation

Future generation from the hydroelectric system is uncertain and will vary over a wide range from year-to-year. The method the Council uses to estimate the impact of that uncertainty is to use historic streamflows to develop a range of potential hydroelectric generation based on the current configuration of the hydroelectric system. An 80-year history of streamflows and generation provides the basis for hydropower generation in the Regional Portfolio Model (RPM).

The hydroelectric generation modeled in the RPM also reflects all known constraints on river operation. These include those river operations associated with the NOAA Fisheries 2014 biological opinion. In addition, all scenarios evaluate resource choices assuming no emergency reliance on the hydropower system, even though such reliance might not violate biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydropower operations must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements.

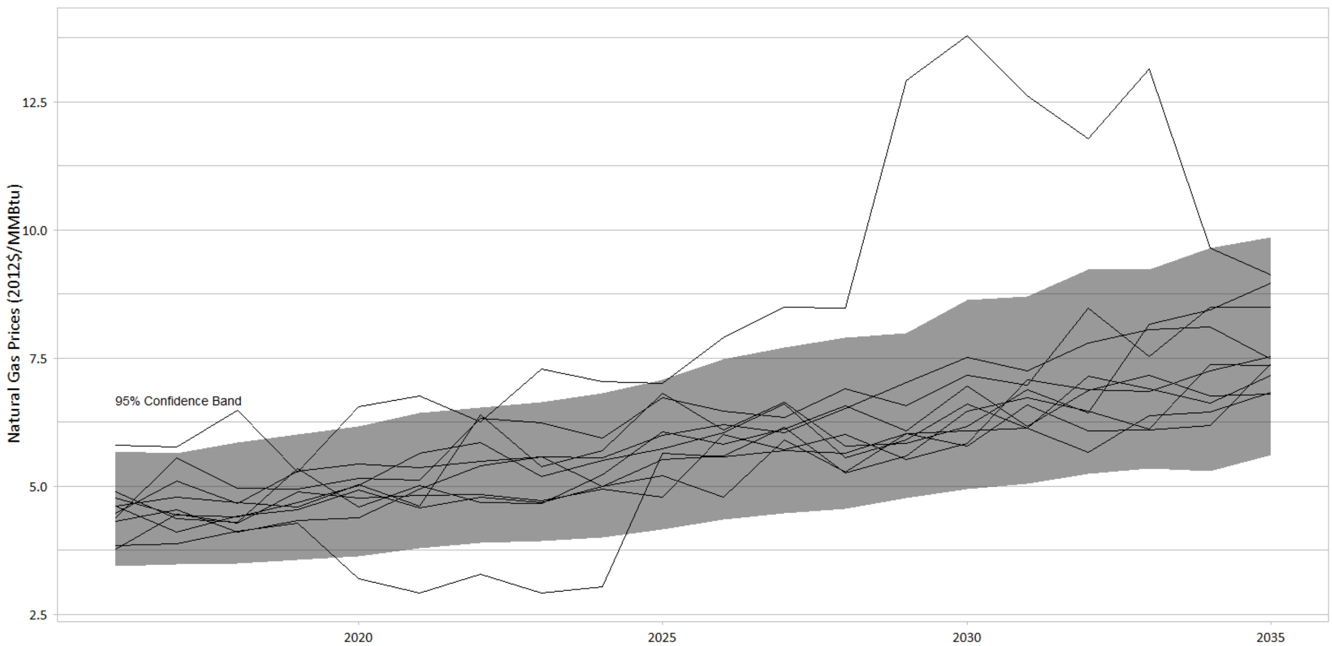
Wholesale Market Prices for Natural Gas and Electricity

There are many market-based prices that impact the cost of the regional power system. In order to test the cost and risk of pursuing different resource strategies, the two types of prices that are most critical are the price of the fuel for thermal generators and the price of buying from or selling into the regional or west coast markets.

Fuel Prices

Forecasts for the fuel prices for thermal generators including coal, uranium and natural gas are described in Chapter 8. Because natural gas is often the marginal fuel source in the region, the price of natural gas is modeled as varying over potential futures. Details of how these future gas price profiles are developed are included in Appendix L. Since coal and uranium are seldom on the margin in setting the price of the market, the forecast for these fuel prices are held constant over the potential futures. Figure 15 - 2 illustrates the potential range for natural gas prices over the 20-year study horizon.

Figure 15 - 2: Example of forecast potential future natural gas prices



External Electricity Market Prices

The Northwest is interconnected to power markets in other regions, most importantly California and the Southwest and British Columbia. These interconnections help the Northwest reduce the cost of serving regional load. Northwest utilities and Bonneville, by either selling electric power to other regions when the Northwest has surplus or buying power from other regions when it is less expensive than producing power from generators within the Northwest, can reduce the cost to consumers in the region. The price of buying and selling power outside the region is impacted by the supply and demand dynamics inside the region. When testing different resource strategies, both the price for importing and exporting electricity and the interaction of those prices with the operation of the power system in the Northwest are modeled as varying over the 800 futures. Regional electricity market prices are estimated by the Regional Portfolio Model (RPM), based on the amount of hydroelectric generation and the dispatch of regional resources. These prices result from supply and demand equilibrium within the region. This equilibrium price can differ from the external market price as is seen by comparing Figure 15 - 3 which shows the market price for imports and exports to Figure 15 - 4 which shows the equilibrium price for in-region generators. A detailed discussion of how these prices are developed appears in Appendix L. The interaction of external market prices with the resource strategy being tested in the RPM is discussed further in the section on *Testing Resource Strategies* later in this chapter.

Figure 15 - 3: Example futures for the prices of importing or exporting electricity

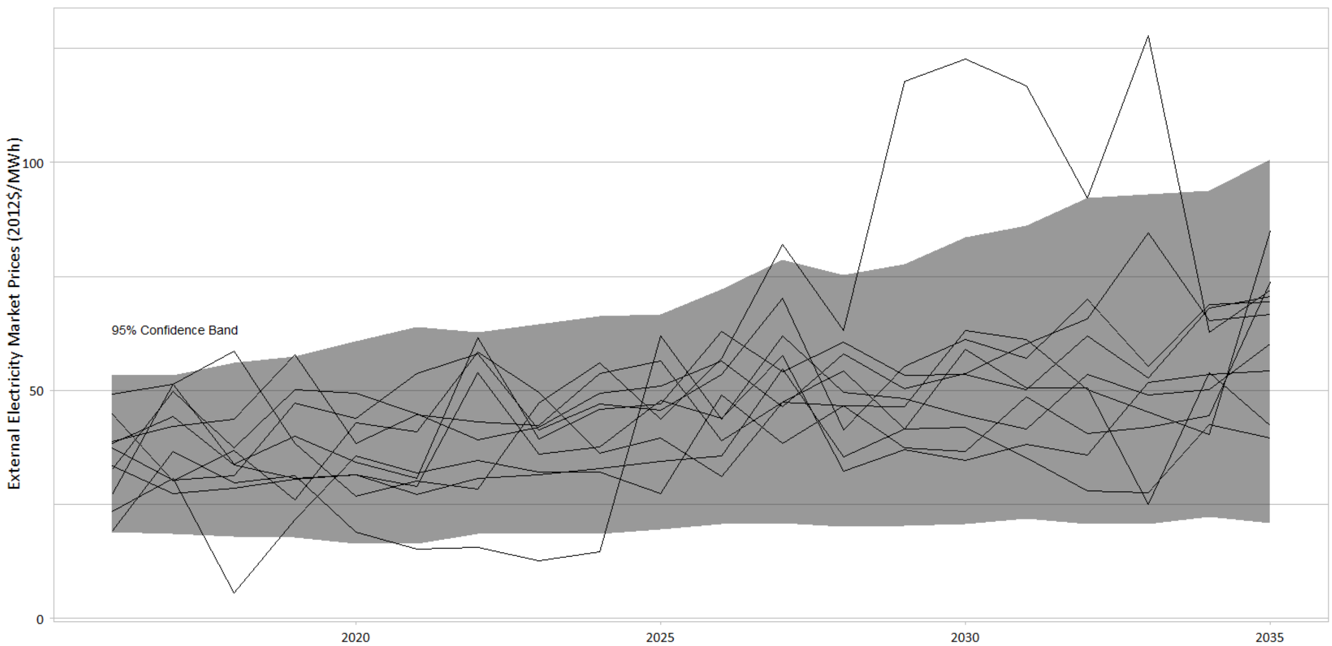
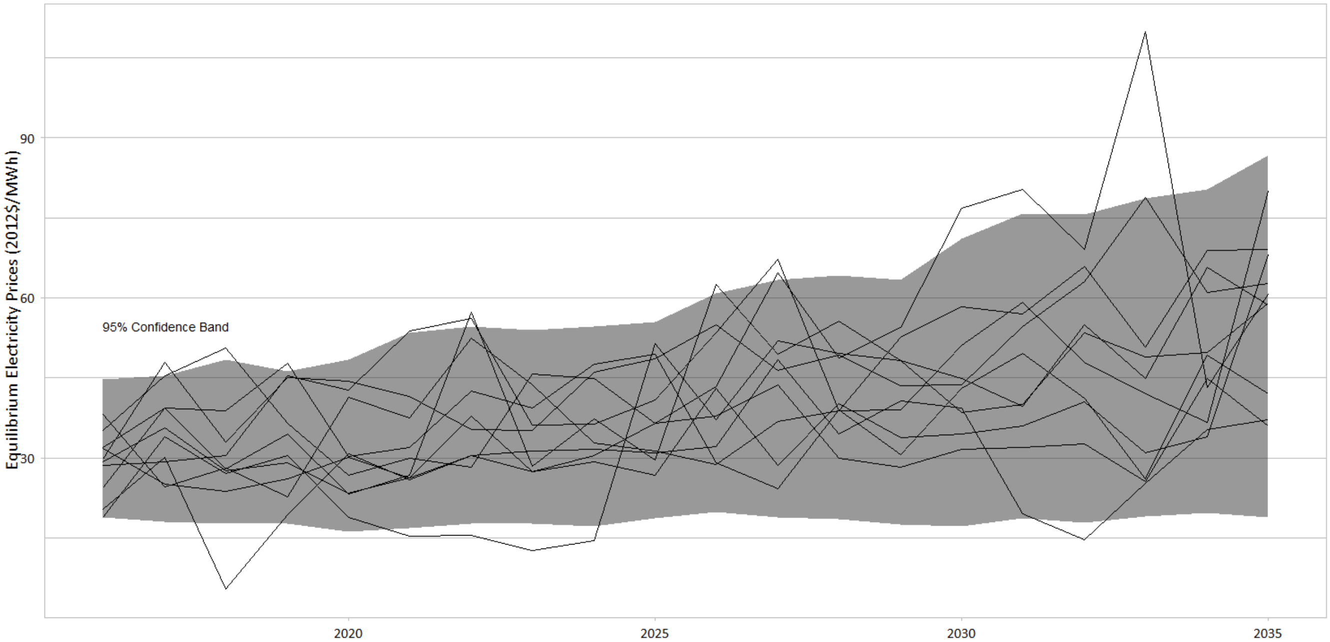


Figure 15 - 4: Examples of equilibrium prices for generators in the region



Carbon Dioxide Emissions Policies

When the Council commenced development of the Seventh Power Plan, state and federal carbon emissions policies were uncertain. Although the federal government recently issued its final regulations covering carbon dioxide emissions from new and existing power generation, state compliance plans are not scheduled (or required) to be completed before the Seventh Power Plan is adopted. Therefore, the Council tested alternative carbon emissions reduction policies to assess their impact on the cost and risk of alternative resource strategies.

Policies to reduce carbon dioxide (CO2) emissions can take several different forms. One policy option is to assign a price to the emission of CO2, whether implicit or explicit. Another approach is to assume the re-dispatch or retirement of resources that emit CO2. A third policy option is to require that a minimum share of resources be non-CO2 emitting (e.g. establish renewable portfolio standards). In analyzing alternative resource strategies, all three of these policy options were tested. The various approaches are discussed further in the section on *Developing Resource Strategies* later in this chapter.

ESTIMATING FUTURE SYSTEM COST

Comparing alternative resource strategies requires measuring differences between these strategies. Perhaps the most important measurement is an estimate of the future cost of the power system. This requires estimating the carrying cost for the existing power generation system as well as forecasting new costs associated with any particular resource strategy. The significant costs and benefits that are evaluated in the RPM are those for conservation, new generating resources and demand response, additional resources to meet renewable portfolio standards (RPS) and operating costs of the existing system.

Conservation

Acquiring conservation has both costs and benefits. To evaluate the value of conservation, the supply is aggregated into blocks of sufficient granularity to not obscure comparison to other resources. The conservation measures and block aggregation strategy are described in Chapter 12. Limitations on the rate at which conservation can be acquired changes throughout the 20-year period of the study. These limits and their derivation are also described in Chapter 12.

All resource strategies tested by the RPM assume that the availability of conservation differs between discretionary and lost opportunity measures. In the case of discretionary conservation, the supply decreases as more is purchased. In the case of lost opportunity conservation, if it is not purchased there is a lag time, determined by the expected life of the measure, before the next opportunity to purchase it occurs. For a more in-depth discussion of how each type of conservation is modeled see Appendix L.

The acquisition of conservation is generally assumed to be dynamically altered based on market conditions. That is, when market prices are higher, higher levels of conservation are cost-effective to develop than when market prices are lower. The RPM, when searching for least cost resource strategies, tests alternative limits on the maximum cost (and hence, the quantity) of conservation it develops. This tests the risk (to the system cost) of getting more or less conservation.

When a conservation measure is acquired it is assumed that its cost covers resource acquisition for the duration of the study. The RPM models the power system on a quarterly basis, i.e., four quarters per year, 80 quarters over the 20 year planning period. Thus, starting with the quarter after conservation is acquired; the levelized cost of the conservation is included in the system cost.

On the benefit side, conservation reduces the need for regional generation to serve load, both energy and capacity. This translates into a benefit when regional generation can sell into the external market and make a profit or when purchases from outside the region can be reduced and thus reduce the system costs.

New Generating Resources and Demand Response

The analysis of resource strategies involves selecting options to develop new generating resources and demand response. In the RPM, as in the real world, establishing an option to develop new resources incurs a small cost for engineering, permitting and siting. A far more significant cost is incurred when a resource is constructed. Because the longest lead time for new resources considered for development in the Seventh Plan is 30 months, for a combined cycle natural gas plant, it is assumed that once construction is started that it will be completed.

The Regional Portfolio Model (RPM) uses two decision rules to determine when a generating resource moves from an option to construction. Resources are built if they are needed to satisfy a regional adequacy requirement or if they are economical, i.e., can recover their full cost by selling into the market. For each resource strategy, the RPM forecasts the need for new resources to meet adequacy as well as the potential for a resource to recover its full cost through sales into the wholesale market. If either one of these evaluations is positive (i.e., the resources is needed to meet adequacy requirements or the resource can recover its full cost through market sales) a resource option will move into the construction phase. When that occurs, the cost of constructing the resource is added into the system costs and the dispatch costs are added in after the construction is complete and the resource is operational.

The RPM calculates the benefits of new generating resources and demand response by comparing the variable cost of the resource to the price for importing or exporting power. If the cost of the new resource, such as conservation, is lower than market prices, the net cost of importing power is reduced or revenue from selling power outside the region increases and is credited toward reducing regional system cost.

Renewable Portfolio Standards

Fulfilling Renewable Portfolio Standards, including accounting for the banking of Renewable Energy Credits, is part of estimating system cost. Currently the states of Montana, Oregon and Washington have Renewable Portfolio Standards. Assumptions for RPS requirements by state, used to evaluate system cost are shown in Table 15 - 1. The percentages of state load assumed to be served by RPS resources are shown in Table 15 - 2. Finally the estimated fraction of load in each state that is obligated under the RPS is given in Table 15 - 3. All resource strategies are assumed to meet RPS requirements in the most cost-effective manner.

Table 15 - 1: Initial RPS Assumptions

	MT	OR	WA
Current qualifying resources (aMW/ yr)	**105**	**759**	**945**
Credits remaining at beginning of study	**69**	**3747**	**1229**
REC Expiration Time (Years)	**3**	**RECs do not expire**	**2**

Table 15 - 2: Percent of Load required to be served by RPS Resources

Calendar Year	MT	OR	WA*
2015	**15.0%**	**15.0%**	**3.0%**
2016 to 2019	**15.0%**	**15.0%**	**9.0%**
2020 to 2024	**15.0%**	**20.0%**	**13.9%**
2025 to 2035	**15.0%**	**19.8%****	**13.9%**

* Numbers for Washington are based on anticipated renewable generation build which are one element of complying with the law that governs RPS; a cost cap of four percent of a utility's retail revenue requirement spent on the incremental cost of renewable energy and a cost cap of one percent if a utility experiences no load growth in a given year serve as alternative sources of compliance.

** In Oregon in 2025, small- and mid-size utilities are included in the requirement

Table 15 - 3: Fraction of State Load Net of Conservation Obligated under RPS

	MT	OR	WA
2015 to 2024	**56%**	**71%**	**76%**
2025 to 2035	**56%**	**100%**	**76%**

Existing Resource Operating Costs

The operating costs of the system, such as fixed operations and maintenance (O&M), variable O&M and fuel costs, are part of the RPM's system cost estimation. Included in the operating costs for existing resources are any fixed O&M or variable O&M that are represent the incremental costs for complying with existing regulations. The fixed portions of these costs are incurred while the existing resources are still in operation and thus are included in the model until a plant retires. The variable costs are part of the dispatch of the system and are included in system costs when an existing resource is dispatched. In addition to the operating cost of existing resources the RPM computation of average present value system cost includes the capital cost of investments required to satisfy environmental regulations.

For evaluation of these costs, the existing natural gas resources are grouped by heat rate. The hydroelectric system is assumed to have a dispatch that varies based on water conditions as described in Chapter 11. Coal resources without an announced retirement date are grouped into a single dispatch block. Resources that do not dispatch to market prices, also called "must-run" resources are grouped into a single block. The largest of the must run resources is the Columbia Generating Station nuclear plant. These blocks are dispatched according to estimated market conditions in economic merit order (i.e., least cost first) when compared to any new resources that are available for dispatch within the same period.

TESTING RESOURCE STRATEGIES

Resource Strategy Definition

A resource strategy is a plan on how to acquire resources. It includes two decision points for a utility. When a utility planner needs to start planning for a resource and when a utility needs to start the construction of a resource. Because of uncertainty about the future, it makes sense to have circumstances where a utility would plan for a resource but choose not to construct it. Thus, each of these decisions must be treated distinctly.

A scenario is a different set of assumptions about future conditions. Scenarios can examine things such as the effect of enacting new legislation on the region's power system or the effect of market regime changes on the power system. Generally, resource strategies reflect decisions that can be made by utilities, whereas scenarios reflect circumstances beyond the control of a utility. A resource strategy is considered *robust* if it exhibits both *low cost* and *low risk* across many different scenarios.

The Regional Portfolio Model

The Regional Portfolio Model (RPM) is used to estimate the system costs of a resource strategy under a given scenario. The RPM is described exhaustively in Appendix L. The RPM tests a wide range of resource strategies including the amount of conservation developed, the amount of demand response optioned and the amount of thermal and renewable resources optioned across 800 potential futures. For each of the 800 potential futures examined, the RPM estimates capital costs for constructing new resources and operating costs of new and existing resources, as described in the previous section of this chapter. Each future then results in an estimate of the system costs.

One of the characteristics of a least-cost resource strategy in the RPM is that options for new generation and DR that are not built in at least one of the 800 futures are removed. That is, it is assumed that these options were not established until there was at least some probability that they would be exercised. Therefore, least cost resource strategies identified in the RPM recommend that options be taken at specific times in the future. In all scenarios examined and for all resources considered, having open options at every opportunity (i.e. continuous optioning) is more expensive. Maintaining these options strictly for crucial times should be a less costly approach for regional utilities to meet the needs of their system.

Resource strategies that minimize both cost and risk are considered optimal for a scenario. The RPM minimizes system cost by seeking resource strategies that reduce the average of the 800 future system cost estimates. The model minimizes system risk by seeking resource strategies that minimize the average of the 80 most expensive future system cost estimates. In this case “optimal” is limited to a comparison of the range of strategies tested by the RPM. Because of the complexity of the system cost calculation in the RPM, it is impossible to guarantee an optimal result without calculating every possible resource strategy. Modern computers are not yet powerful enough to complete this level of calculation in a reasonable amount of time. Instead some enhanced methods of searching through the resource strategies were used. Further discussion of this is found in Appendix L.

Uncertainty in System Costs

As described in the previous section, each resource strategy results in a distribution of system costs. These distributions highlight the fact that future system costs are unknown. Figure 15 – 5 illustrates the cost distributions for two different strategies and Figure 15 - 6 gives an example of the system cost distribution for several different scenarios, which will be detailed later in this chapter.

Figure 15 - 5: How to interpret distribution graphs

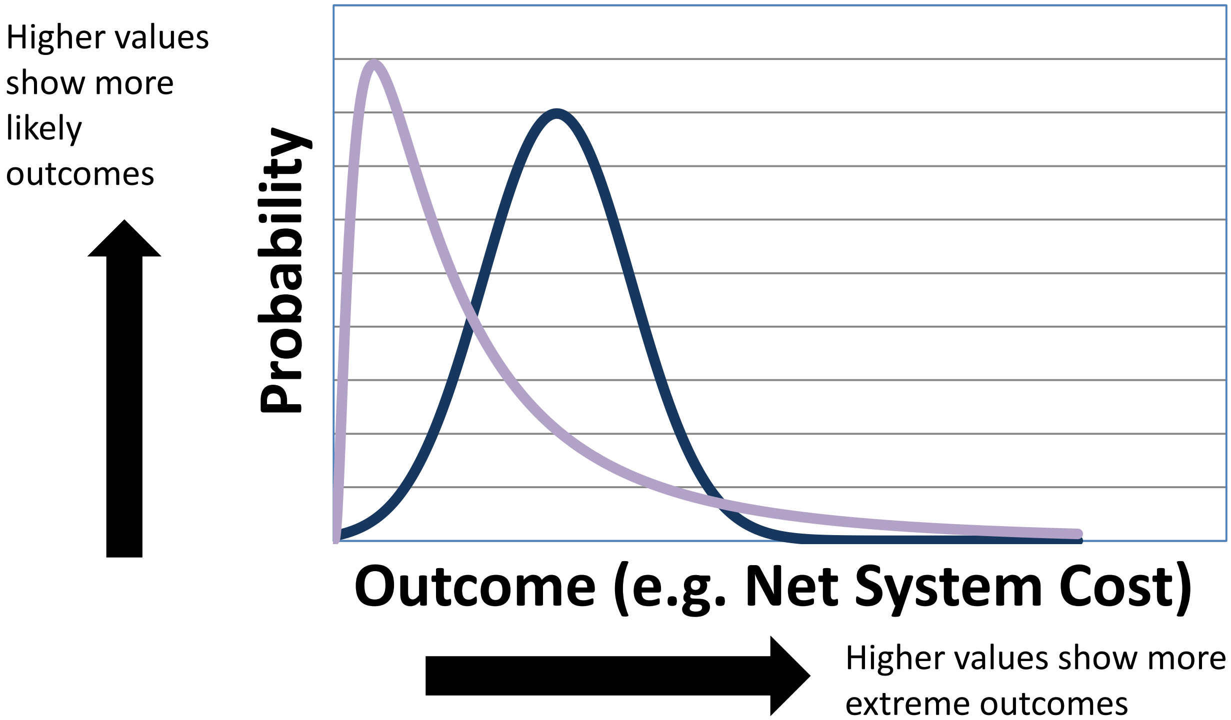
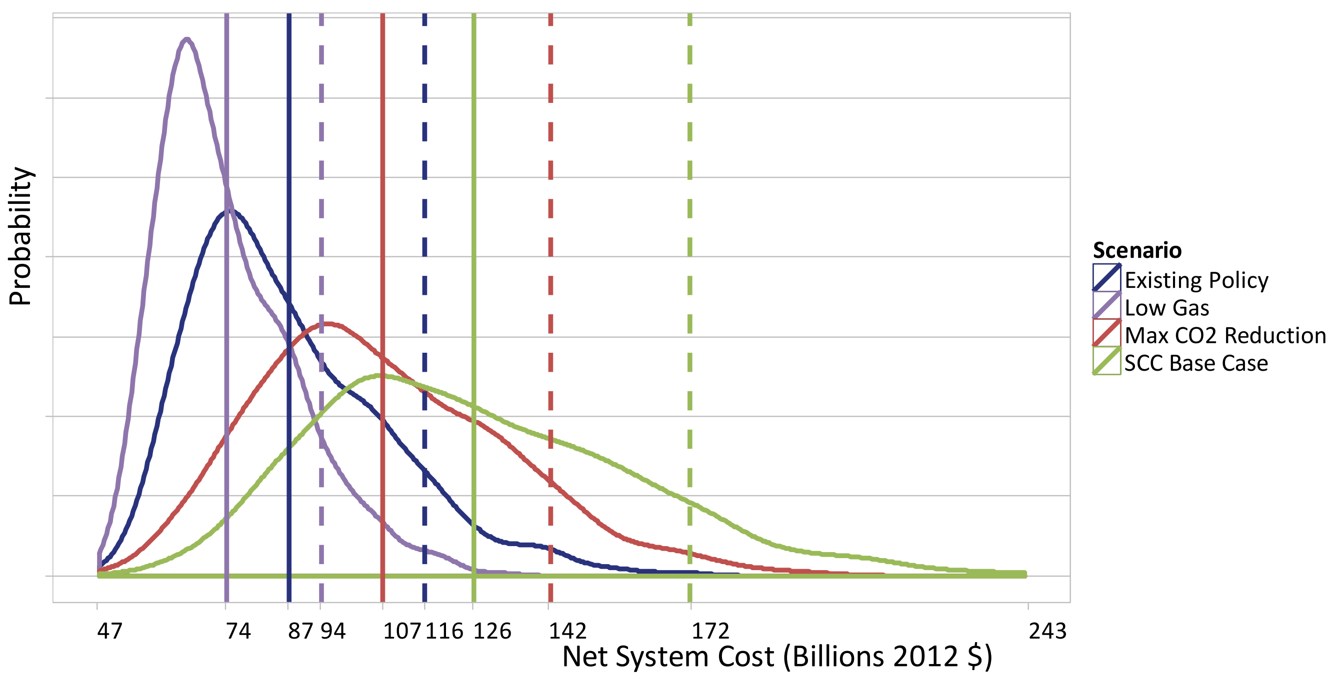


Figure 15 - 6: Distribution of System Costs Example



When testing resource strategies, the uncertainty represented by the cost distribution associated with a scenario helps describe the impact of a scenario. How the impact is interpreted depends on the scenario. For example, in a scenario where low gas prices are assumed to persist throughout the study the power system costs are much lower than a scenario that assumes broader range of future gas prices. However, while the lower cost in this scenario would likely be a boon for the consumers of electricity, the least cost resource strategy for this scenario might be highly dependent upon future conditions that are outside of the control of the Northwest. In contrast, under a scenario which assumes retirements of generating resources, regional decision-makers can implement a least cost resource strategy that might include more conservation, options for demand response and construction of new thermal generators. Therefore, when there is uncertainty in future system cost it is important to understand the sources of that uncertainty and specifically whether options to mitigate that cost risk are within the control of the region. The resource strategy described in Chapter 3 was developed by considering these criteria.

Resource Strategy Adequacy

A detailed description of how the Council's resource adequacy standard is implemented in the Regional Portfolio Model is provided in Chapter 11. The RPM tests a resource strategy for adequacy by testing whether its resources meet a minimum build requirement for both energy and capacity adequacy standards. In the event that the strategy does not have sufficient resource to meet adequacy standards, a cost penalty is assessed. Further, if the deficiency in resources leads to a load curtailment during the dispatch of resources, a further cost penalty is assessed. When the RPM looks for an optimal (i.e., low cost, low risk) resource strategy, the cost penalty is part of that calculation. The cost penalty is set around $6 million per quarter in real 2012 dollars. This cost penalty is added to the system cost per peak megawatt or average megawatt for capacity and energy inadequacies. The amount of the cost penalty imposed was selected to make being inadequate more expensive than the development of any of the resource options for a single quarter. The penalty for load curtailment is $10,000 per megawatt-hour curtailed (2012$). A more detailed description of how resource adequacy is modeled in RPM appears in Appendix L.

When system costs are reported they do not include the cost penalty. This is because the cost penalty is simply a mechanism used in the RPM to ensure sufficient resources are development to satisfy the regional adequacy standards, rather than an actual cost that must be recovered in utility revenue requirements.

In the Seventh Plan all least cost resource strategies must also provide similar levels of reliability. As a result, the least-cost resource strategy identified by the RPM is often the same or very similar to the least-risk resource strategy. That is, because the resource adequacy cost penalties make it very expensive to pursue a high risk strategy, minimizing economic risk is not much different that minimizing cost. For all scenarios where optimization was run on minimizing cost and then on minimizing economic risk, no significant differences were present. In the Sixth Power Plan, there was extensive discussion about a trade-off between cost and economic risk in resource strategies. This is well-founded portfolio theory, which described the dynamics of the economics of the power system at that time. Currently, the RPM does not show significant trade-offs for strategies that meet adequacy criteria. However, future technologies or market conditions may change this dynamic. Part of analyzing resource strategies for future plans will be determining if there is significant difference between minimizing cost and minimizing risk and describing what factors drive the difference, if any.

DEVELOPING SCENARIOS

Testing resource strategies over many potential futures helps determine if those strategies are cost-effective including consideration of potential future risks. One concern in assessing these risks is that the estimated range of these risks does not have an appropriate assessment of the likelihood of a specific future condition occurring. While many of the methods have underlying models that assign a probability or likelihood to a potential future condition, developing scenarios helps test if resource strategies are robust under different future conditions. For a more detailed description of the underlying likelihood models or distributional assumptions used in developing the futures see Appendix L. The rationale for selecting the scenarios tested in the development of the Seventh Power Plan and general description of these scenarios appears in Chapter 3. This section describes how these scenarios were characterized in the RPM.

Scenarios without Carbon Costs

Existing Policy

In this scenario, the price associated with CO2 emissions was set to zero. This scenario tested resource strategies that have no consideration for CO2 emission cost or risk. However, it does reflect the impact of existing state laws and regulations. For example, due to existing state regulations in Oregon, Washington and Montana that limit CO2 emissions from new power generation facilities, new coal plants were not considered for development in the Seventh Plan. State Renewable Portfolio Standards were also reflected in this scenario. This scenario did not explicitly consider the Environmental Protection Agency's limits on CO2 emissions from new and existing power generation. All other uncertainties (e.g., gas and electricity market prices, load growth) were included.

Maximum Carbon Reduction - Existing Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. Only the first six blocks of conservation resources described in Chapter 12 were available for development. The levelized cost of utility scale solar PV resources was assumed to decline by 19 percent by 2030.

Maximum Carbon Reduction - Emerging Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. However, unlike the prior scenario, no new natural gas-fired generation was available for development. All seven blocks of conservation resources, plus 1100 average megawatts of emerging energy efficiency technologies were made available for development. In addition, distributed solar PV technology in both the residential and commercial sectors was considered for development. Although costs were not considered in this scenario, the levelized cost of utility scale solar PV were assumed to decline by 28 percent by 2030. This assumption increased the maximum availability of this resource. The emerging generating technologies considered are described in Chapter 11 and the emerging energy efficiency technologies considered are described in Chapter 12.

Regional 35 Percent RPS

This scenario involves applying the RPS requirements to all regional loads and increasing that requirement to 35 percent by 2027. This was ramped in for both the percentage of load (net of conservation) to which it applied and the level of RPS. Table 15 - 4 shows the RPS requirement assumptions by state and Table 15 - 5 shows the percentage of load in each of the four states to which the RPS was applied. Both of these were designed to reach the full RPS requirements by 2027 so the three year average of CO2 emissions in 2030 would reflect the full RPS achievement. The annual requirements only reflect potential incremental changes to get from current conditions to the 35 percent renewable generation for 100 percent of the load in each state.

Table 15 - 4: RPS Requirement Scenario Assumptions

Simulation CY	MT	OR	WA	ID
2015	**15%**	**15%**	**3%**	**0%**
2016	**17%**	**17%**	**9%**	**3%**
2017	**18%**	**18%**	**11%**	**6%**
2018	**20%**	**20%**	**14%**	**9%**
2019	**22%**	**22%**	**16%**	**12%**
2020	**23%**	**23%**	**18%**	**15%**
2021	**25%**	**25%**	**21%**	**18%**
2022	**27%**	**27%**	**23%**	**20%**
2023	**28%**	**28%**	**26%**	**23%**
2024	**30%**	**30%**	**28%**	**26%**
2025	**32%**	**32%**	**30%**	**29%**
2026	**33%**	**33%**	**33%**	**32%**
2027 to 2035	**35%**	**35%**	**35%**	**35%**

Table 15 - 5: Percent of Obligated Load Assumptions

Simulation CY	MT	OR	WA	ID
2015	**56%**	**71%**	**76%**	**0%**
2016	**60%**	**73%**	**78%**	**8%**
2017	**63%**	**76%**	**80%**	**17%**
2018	**67%**	**78%**	**82%**	**25%**
2019	**71%**	**81%**	**84%**	**33%**
2020	**74%**	**83%**	**86%**	**42%**
2021	**78%**	**86%**	**88%**	**50%**
2022	**82%**	**88%**	**90%**	**58%**
2023	**85%**	**90%**	**92%**	**67%**
2024	**89%**	**93%**	**94%**	**75%**
2025	**93%**	**95%**	**96%**	**83%**
2026	**96%**	**98%**	**98%**	**92%**
2027 to 2035	**100%**	**100%**	**100%**	**100%**

No Demand Response - No Carbon Cost

For this scenario, the resource strategies were restricted so that they could not select demand response resources as options. For a description of the optioning logic in the RPM see the earlier section in this chapter on estimating the cost of new generating resources and demand response.

Low Fuel and Market Prices - No Carbon Cost

This scenario explores the implications of extremely low natural gas prices and the corresponding impacts on other fuel and electricity prices. This includes a reduction in coal prices, for example the price for coal in Montana start around $0.03 less per MMBTU in this scenario and by 2035 are around $0.17 less in real 2012 dollars. The range of natural gas prices is based on re-centering the prices around the low forecast range as described in Chapter 8. The resulting range of natural gas prices can be seen in Figure 15 - 7. The electricity prices used in examining the resource strategies under this scenario are then centered around an electricity price forecast based on this low natural gas price forecast and the resulting range of electricity prices for importing or exporting power generation can be seen in Figure 15 - 8.

Figure 15 - 7: Range of Natural Gas Prices

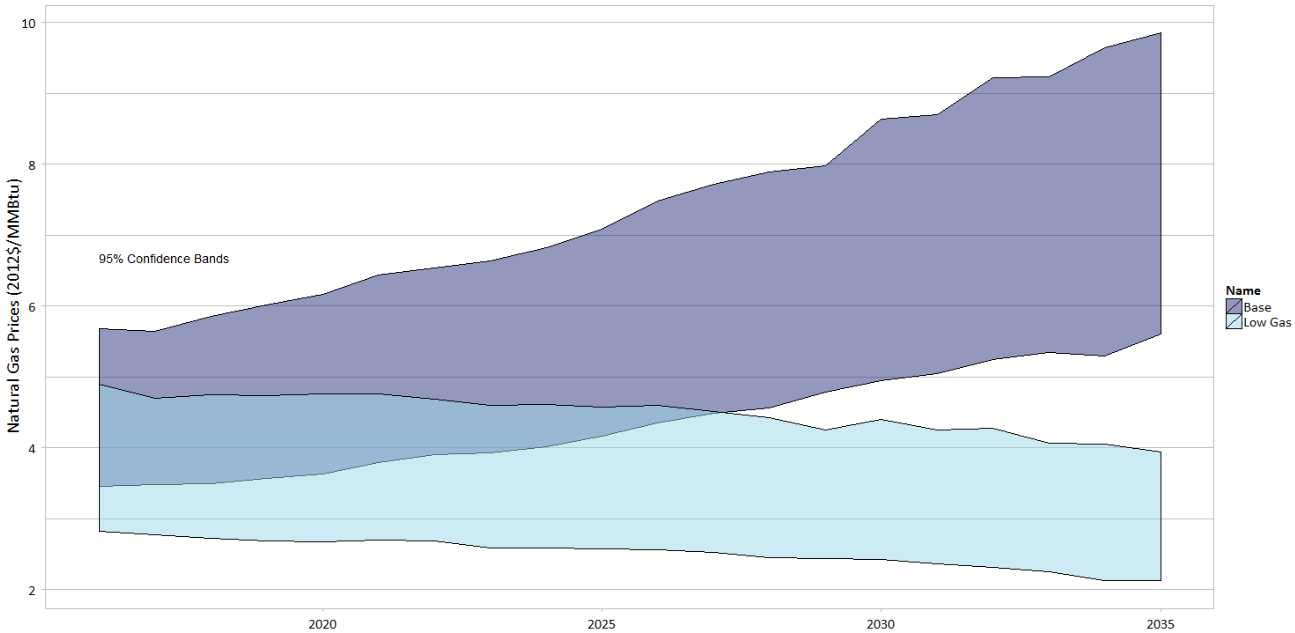
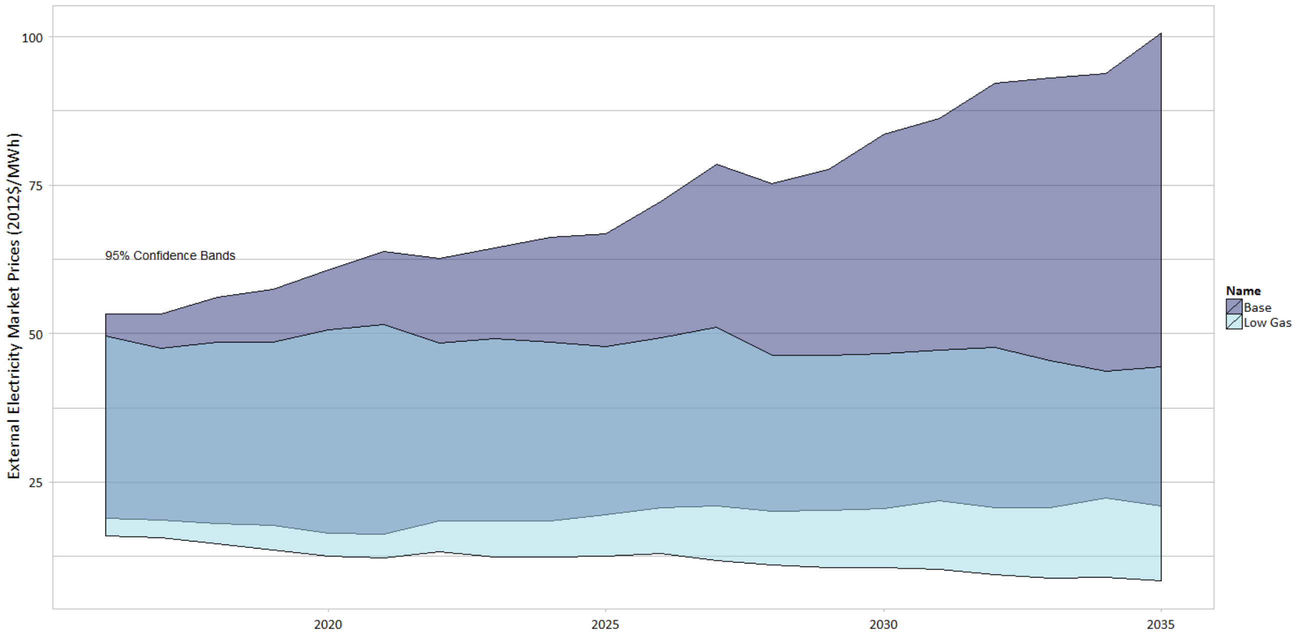


Figure 15 - 8: Range of Electricity Prices



No Coal Retirement

In this scenario, the announced retirements of the Boardman, Centralia and North Valmy resources was taken out of the model. This was used to determine the impacts of these retirements on the resource strategy.

Lower Conservation - No Carbon Cost

In this scenario, the resource strategy was limited so that conservation could only be purchased if its cost was anticipated to be at or below short-run market prices. These same restrictions were not applied to other resources. This scenario is useful in examining the cost of this conservation purchasing scheme compared to developing conservation at a level that minimizes future power system costs where it is purchased on an equivalent basis to other resources.

Scenarios with Carbon Costs

Social Cost of Carbon - Mid-Range and High-Range

These scenarios assumed that alternate values of the federal government's estimates[2] for damage caused to society by climate change resulting from carbon dioxide emissions, referred to as the Social Cost of Carbon, are imposed beginning in 2016. The mid-range scenario used the average cost estimated with a 3 percent discount rate. The high-range scenario used an estimate of possible

[2] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

damage cost that should not occur more than 5 percent of the time. Values for these scenarios are given in Table 15 - 6.

By internalizing carbon costs, this analysis identifies strategies that minimize all costs, including carbon.

The model essentially reduces carbon emissions when they can be avoided at the social cost of carbon or less. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon emissions would be the maximum society should invest to avoid such damage.

Table 15 - 6: Social Cost of Carbon Assumptions (2012$/Metric Ton of CO2)

Fiscal Year	Mid-Range	High-Range
FY16	$40.99	$121.00
FY17	$42.07	$125.00
FY18	$43.15	$129.00
FY19	$45.31	$134.00
FY20	$46.39	$138.00
FY21	$46.39	$141.00
FY22	$47.47	$145.00
FY23	$48.54	$148.00
FY24	$49.62	$151.00
FY25	$50.70	$154.00
FY26	$51.78	$158.00
FY27	$52.86	$161.00
FY28	$53.94	$164.00
FY29	$55.02	$167.00
FY30	$56.10	$172.00
FY31	$56.10	$175.00
FY32	$57.17	$178.00
FY33	$58.25	$181.00
FY34	$59.33	$186.00
FY35	$60.41	$189.00

Carbon Cost Risk

In this scenario, the price associated with CO2 per metric ton was modeled as a regulatory risk. The range of the potential carbon price was fixed between $0 and $110 in real 2012 dollars. The price can be applied starting from 2015 through 2035. Uncertainty about the starting date of the potential CO2 price makes this pricing scheme more consistent with an explicit price for CO2. This scenario was consistent with the CO2 risk scenario analyzed in the Sixth Power Plan and allows for some comparison between plans. More detail on the CO2 risk model is included in Appendix L.

Resource Uncertainty – Planned and Unplanned Loss of a Major Resource

Two scenarios were run to examine the impacts of resource uncertainty. In the first scenario non-CO2 emitting resources were retired in 2016, 2019, 2022 and 2025 for a combined total of about 1,000 megawatts nameplate. The other scenario involved a single similarly sized non-CO2 emitting resource, which was randomly shut down or retired sometime between 2016 and 2035. This was done using a uniform probability of retirement during each quarter.

Faster and Slower Conservation Deployment

These scenarios involved changing the input assumptions for maximum achievable conservation per year. Chapter 12 discusses the development of the input assumptions for faster and slower ramping of conservation programs. For a more detailed description of how the maximum available conservation per year, the percent of that conservation that can be achieved by program year and the maximum conservation that can be achieved over the 20-year study period see Appendix L.

No Demand Response – Carbon Cost

This scenario is the same as the **No Demand Response - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

Low Fuel and Market Prices – Carbon Cost

This scenario is the same as the **Low Fuel and Market Prices - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

Increased Reliance on External Markets

One of the RPM's input assumptions is the maximum level of reliance on out-of-region markets permitted to meet regional adequacy standards. In this scenario, this assumption was relaxed, i.e., reliance on out-of-region markets was increased. To implement this, the GENESYS model was run to determine the Adequacy Reserve Margins (ARM) under the assumption that maximum market reliance is 3,400 MW during high load hours in the winter instead of 2500 MW during high load hours in the winter currently used in the Resource Adequacy Assessment.[3] Since the ARM is a "reserve margin" over in-region utility controlled resources, the assumption of greater external market reliance lowers the ARM requirements. The ARM values were recalculated with a higher expectation of import availability. The result of this is that fewer in-region resources are required to be built for capacity. While the ARM for energy is roughly the same in this scenario at around -3.0 percent, the ARM for capacity is reduced from around 3.0 percent to almost -1.0 percent.

[3] The basis of and methodology used to develop the Adequacy Reserve Margins are described in Chapter 11.

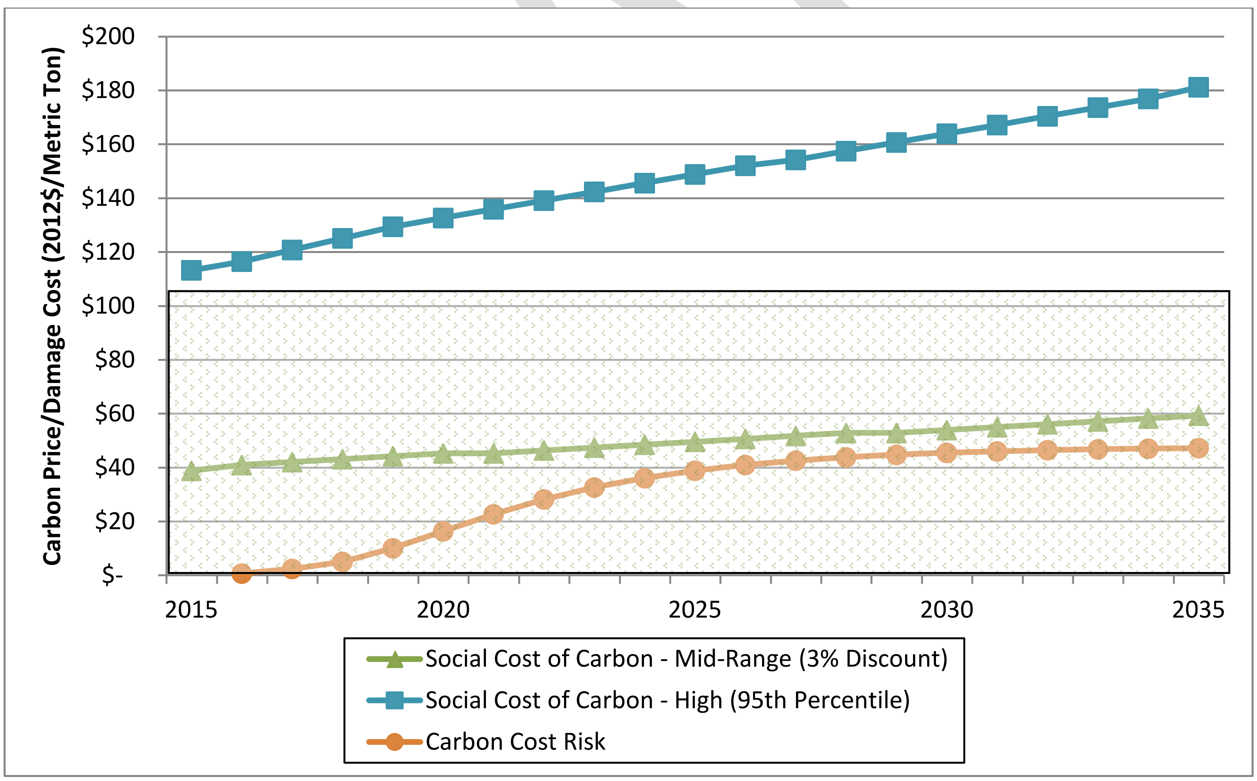
EXAMINING RESULTS

Carbon Emissions

As in the Sixth Power Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon regulations. In addition, the Council was asked to address what changes would be needed to the power system to reach a specific carbon reduction goal and what those changes would cost. This section summarizes how alternative resource strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency. In providing analysis of carbon emissions and the specific cost of attaining carbon emission limits, the Council is not taking a position on future climate-change policy. Nor is the Council taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emission regulations. The Council's analysis is intended to provide useful information to policy-makers.

Figure 15 - 9 shows the two U.S. Government Interagency Working Group's estimates used for the two **Social Cost of Carbon** scenarios and the range (shaded area) and average carbon prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Risk** scenario.

Figure 15 - 9: Carbon Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Carbon prices or estimated damage costs are not included in the **Existing Policy** scenario, nor are they included in the **Maximum Carbon Reduction** - **Existing Technology** or **Regional 35 Percent RPS** scenarios describe earlier in this chapter. Therefore, comparing the cost and emissions from these scenarios provides insights into the impact of alternative policy options for reducing carbon emissions.

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 a strategy’s 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 of any strategy 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%** scenarios. Therefore, only the direct costs of the least cost resource strategies for these scenarios are reported.

Figure 15 - 10 shows the direct resource strategy average system costs and carbon emissions from the ten scenarios and sensitivity studies conducted to specifically evaluate carbon emissions reduction policies (and risks) for the development of the Seventh Power Plan. This figure shows the average net present value system cost (bars) for the least cost resource strategy for each scenario, both with and without carbon tax revenues. It also shows the average carbon emissions projected for the generation that serves the region in 2035.

Figure 15 - 10: Average System Costs and PNW Power System Carbon Emissions by Scenario in 2035

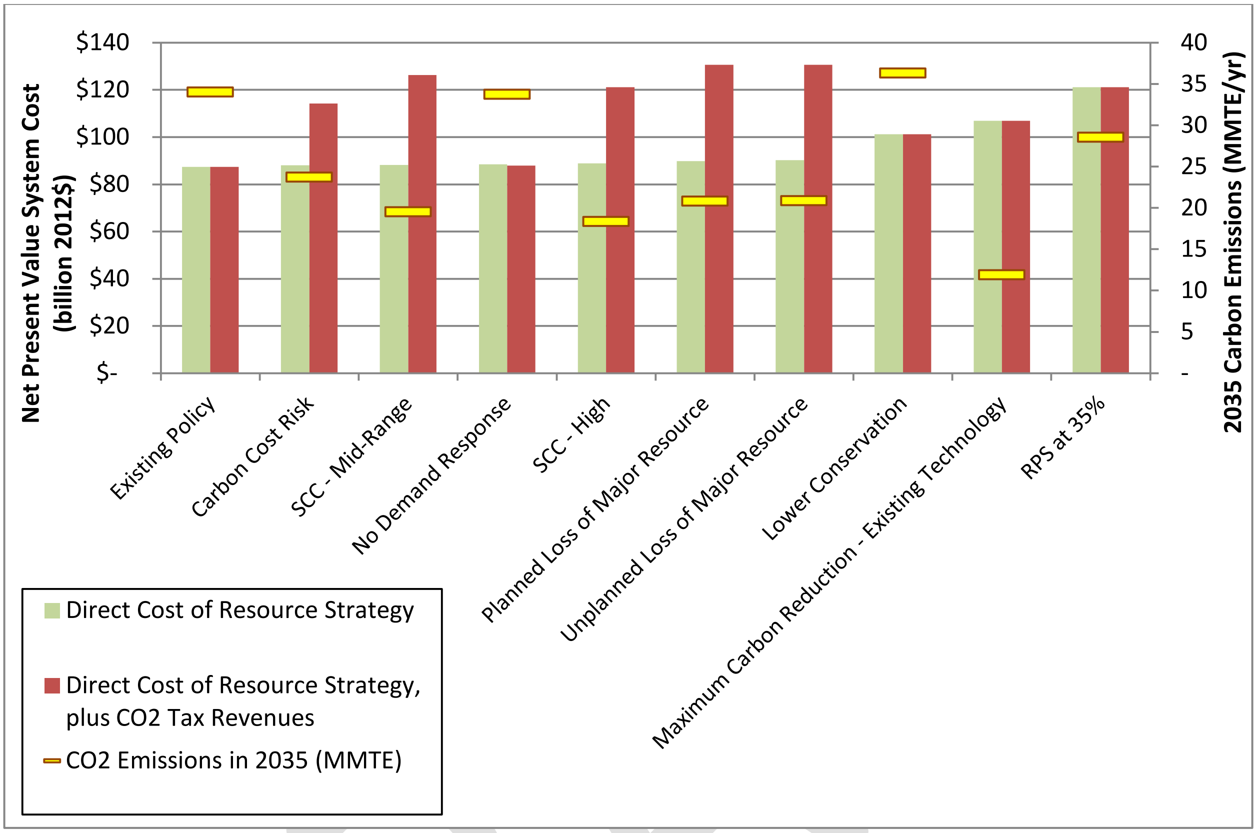


Figure 15 - 10 shows the **Existing Policy** scenario results in carbon emissions in 2035 of 34 million metric tons. This scenario assumed no additional policies to reduce carbon emissions beyond currently announced coal plant retirements are pursued. The average present value system cost of this resource strategy is $88 billion (2012$). The **Social Cost of Carbon – Mid-Range** (SCC-Mid-Range) and **Social Cost of Carbon – High-Range** (SCC-High**)** scenarios reduce carbon emissions to about between 18 to 20 million metric tons in 2035. The average system cost, excluding the carbon tax revenues for these scenarios is $0.8 billion for the **SCC – Mid-Range** and $1.6 billion for the **SCC – High** more than the average system cost of the **Existing Policy** scenario.

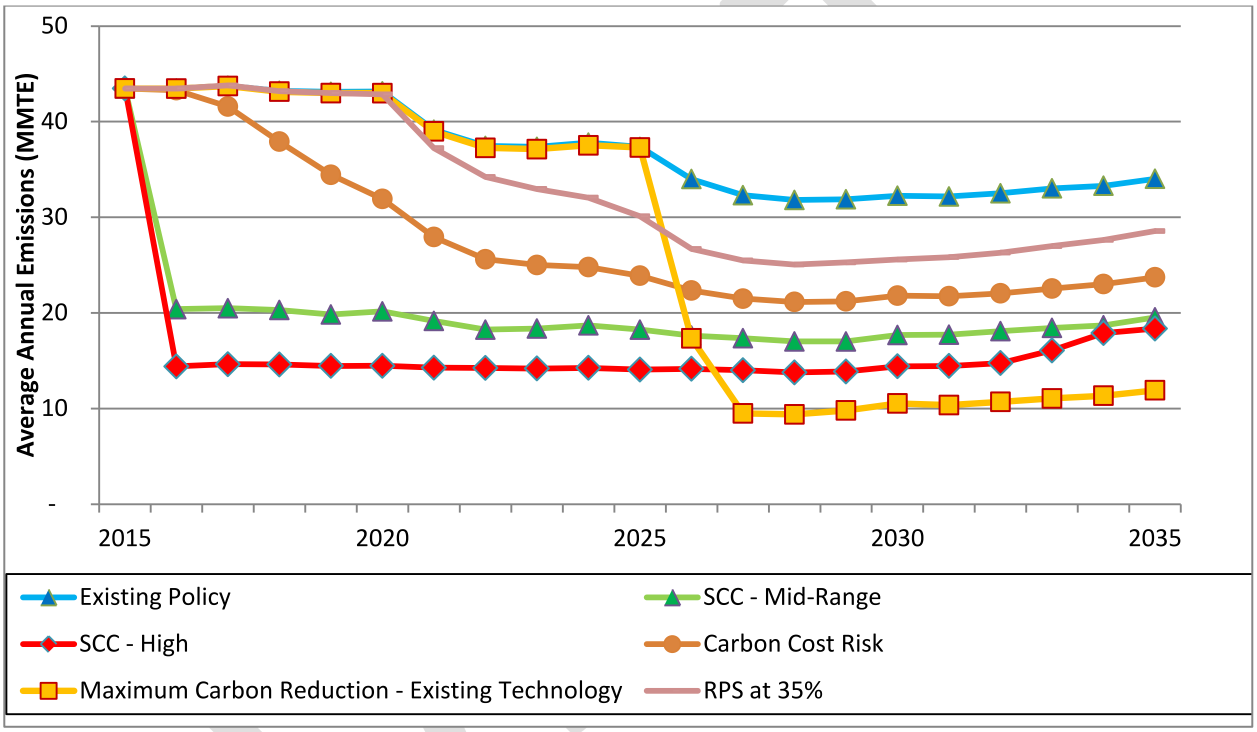
Under the **Carbon Cost Risk** scenario, 2035 carbon emissions were reduced to 24 million metric tons, or 10 million metric tons below the **Existing Policy** scenario. The average present value cost of this scenario, net of carbon tax revenues is $0.7 billion above the **Existing Policy** scenario. Under the **Maximum Carbon Reduction – Existing Technology** scenario, 2035 carbon emissions are reduced to 12 million metric tons and average system cost is are approximately $20 billion over the **Existing Policy** scenario. The large increase in average system cost for this scenario over the **Existing Policy** case results from the replacement of all of the region's existing coal and inefficient natural gas fleet with new, more efficient natural gas-fired combustion turbines.

The **RPS at 35%** scenario reduces 2035 carbon emissions to just under 30 million metric tons. This is a reduction of around 5 million metric tons per year compared to the **Existing Policy** scenario.

The direct cost of this resource strategy is approximately $121 billion or $34 billion more than the **Existing Policy** scenario.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 15 - 11 shows the annual emissions level for each scenario. A review of Figure 15 - 11 reveals that the two social cost of carbon 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 Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

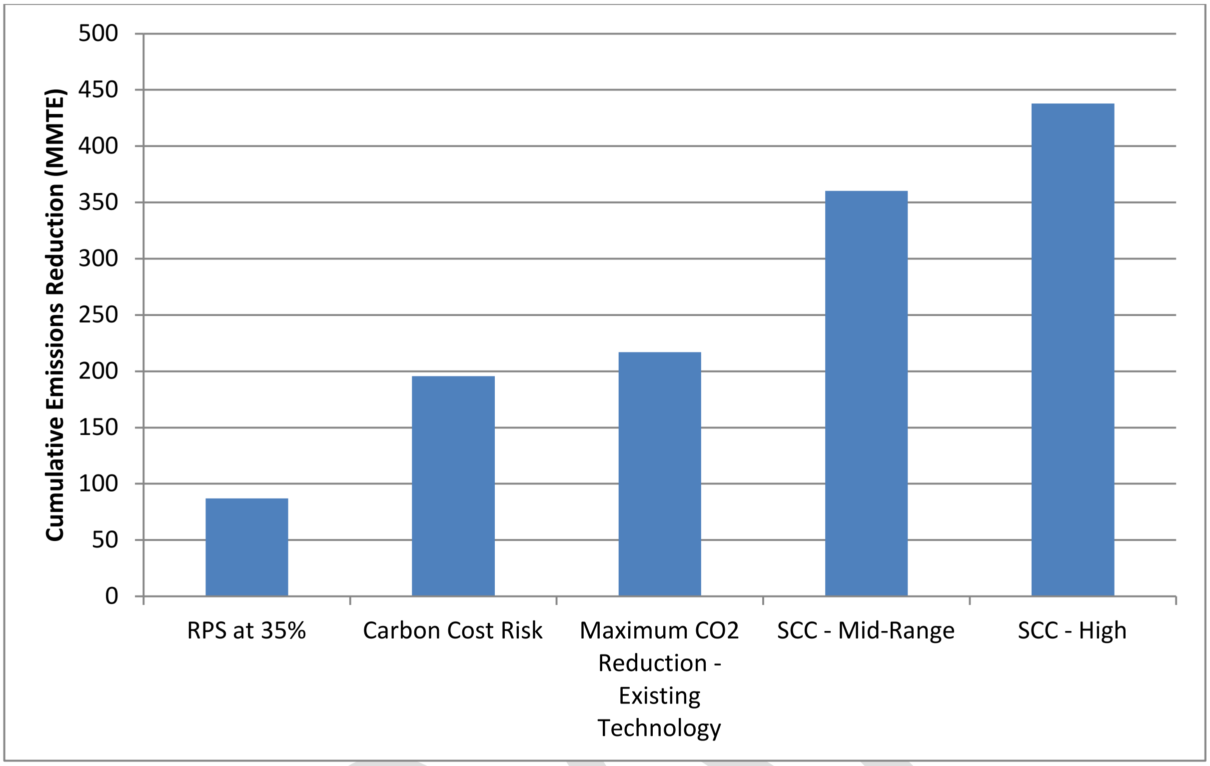
Figure 15 - 11: Average Annual Carbon Emissions by Carbon Reduction Policy Scenario



The **Carbon Cost Risk** and **RPS at 35%** scenarios gradually reduce emissions, while the Maximum Carbon Reduction scenario dramatically reduces emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of CO2 emitting generation.

Figure 15 - 12 shows the cumulative reduction in carbon emissions for the carbon reduction policy scenarios compared to the **Existing Policy** scenario.

Figure 15 - 12: Cumulative 2016 to 2035 Carbon Emissions Reductions for Carbon Policy Scenarios



A comparison of Figure 15 - 11 and Figure 15 - 12 shows that the largest cumulative emissions reductions do not necessarily result from policy options that produce the lowest emission rate in 2035. For example, both social cost of carbon scenarios result in higher emission levels *in* 2035 than the **Maximum Carbon Reduction – Existing Technology** scenario. However, both social cost of carbon scenarios also produce much larger cumulative reductions over the entire planning period.

It should be noted, that the differences in cumulative emissions across these policy options are largely an artifact of the scenario modeling assumptions, which assume immediate imposition of the social cost of carbon. It is unlikely that such large carbon damage cost would or could be imposed in a single step without serious economic disruption. Therefore, the cumulative carbon emission reductions from the implementation of a carbon pricing policy which phases in carbon cost over time, similar to the **Carbon Cost Risk** scenario, are likely more representative of the actual impacts of imposing a carbon price based on the social cost of carbon.

Table 15 - 7 shows cumulative emissions reduction in carbon from the **Existing Policy** for the five carbon reduction policy options and the incremental system cost net of carbon tax revenues. Table 15 - 7 reveals that three carbon pricing policies have roughly comparable cost per unit of carbon dioxide emission reduction, ranging from $2 to $4 per metric ton. The **Maximum Carbon Reduction – Existing Technology** scenario, as can be seen from Figure 15 - 11, results in the lowest average annual carbon emissions from the regional power system by 2035, but also has a significantly higher average system cost and cost per unit of carbon dioxide reduction ($90/metric ton).

It should be noted that the direct cost of the resource strategies shown for the three carbon-pricing policies are likely understated. This is because all of three scenarios, but especially the two social cost of carbon scenarios, result in immediate and significant reductions in the dispatch of the region's existing coal-fired generation in the model. In practice, at such reduced levels of dispatch, most or all of these plants would likely be retired as uneconomic. As a result, the actual direct cost of carbon reduction under these scenarios would probably be closer to the **Maximum Carbon Reduction – Existing Technology** scenario.

Table 15 – 7: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies Compared to Existing Policy Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMTE)	Cumulative Emission Reduction Over Existing Policy Scenario (MMTE)	Incremental Average System Cost Net of Carbon Tax Revenues Over Existing Policy Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction (2012$/Metric Ton)
SCC - Mid-Range	360	$ 0.8	$ 2
SCC - High	438	$ 1.5	$ 4
Carbon Cost Risk	196	$ 0.7	$ 3
Maximum Carbon Reduction - Existing Technology	217	$ 19.6	$ 90
RPS at 35%	87	$ 33.9	$ 389

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon emissions will continue beyond 2035, as will their carbon emissions impacts. These "end-effects" could alter the perceived relative cost-efficiency of carbon reduction policy options. 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 **Social Cost of Carbon – 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 emission 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. Considering these "end effects", care should be exercised inferring the most effective method for reducing carbon emissions. The cumulative emissions reductions shown in Table 15 - 7 can be misleading if not considered with the context of these effects.

Maximum Carbon Reduction – Emerging Technology

In the preceding discussion the lower bound on regional power system carbon dioxide emissions was limited by existing technology. Under that constraint, the annual carbon dioxide emissions from the regional power system could be reduced from an average of 55 million metric tons per year today to approximately 12 million metric tons in 2035.[4] While this represents nearly an 80 percent reduction in emissions, it does not eliminate power system carbon dioxide emissions entirely. In order to achieve that policy goal, new and emerging technology must be developed and deployed.

To assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035, the Council created a 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.

Tables 15 - 8 and 15 - 9 summarize the potential resource size and cost of energy efficiency and generating resource emerging technologies considered in this scenario that were modeled in the RPM. A review of Table 15 - 8 shows that an additional 650 average megawatts of emerging energy efficiency technology could be deployed by 2025. If this technology were cost-effective to acquire, it could reduce winter peak demands in that year by 1,350 megawatts. Five years later, by 2030, potential annual energy savings could reach 1,125 average megawatts and reduce winter peak demands by 2,350 megawatts. Only about one-third of these potential savings is currently forecast to cost less than $30 per megawatt-hour and the remaining two-thirds of the potential savings is anticipated to cost more than $80 per megawatt-hour. See Chapter 12 and Appendix G for a more detailed discussion of these emerging energy efficiency technologies.

The regional potential of both utility scale and especially distributed solar PV resources, as shown in Table 15 - 9, is quite large. Assuming significant cost reductions in utility scale solar PV system installations by 2030, the levelized cost of power produced from such systems could be around $50 per megawatt-hour. However, while both utility scale and distributed solar PV systems can significantly contribute to meeting summer peak requirements, they provide little or no winter peak savings. In the near term, this limits their applicability to the region's needs. However, since the region's summer peak demands are forecast to grow more rapidly than winter peak demands, the system peak benefits of these systems are expected to increase over time. See Chapter 11 and Appendix H for a more detailed discussion of these emerging technologies.

Figure 15 - 13 shows the distribution of annual carbon dioxide emissions in 2035 for both the **Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction – Emerging Technology** scenarios. Inspection of Figure 15 - 13 reveals that with existing technology

[4] Average regional power system carbon dioxide emissions from 2000 – 2012 were approximately 55 million metric tons.

carbon dioxide emissions can be reduced to 12 million metric tons per year by 2035. If the emerging energy efficiency and renewable resource technologies shown in Tables 15 - 8 and 15-9 are available for deployment, carbon dioxide emissions in 2035 could be reduced to 6 million metric tons per year. The range in annual carbon dioxide emissions for both scenarios is largely driven by Northwest hydroelectric generation output and future load growth. However, under the scenario where emerging technology becomes available, the range of future emissions is narrower, largely due to less reliance on natural gas-fired generation under low water conditions.

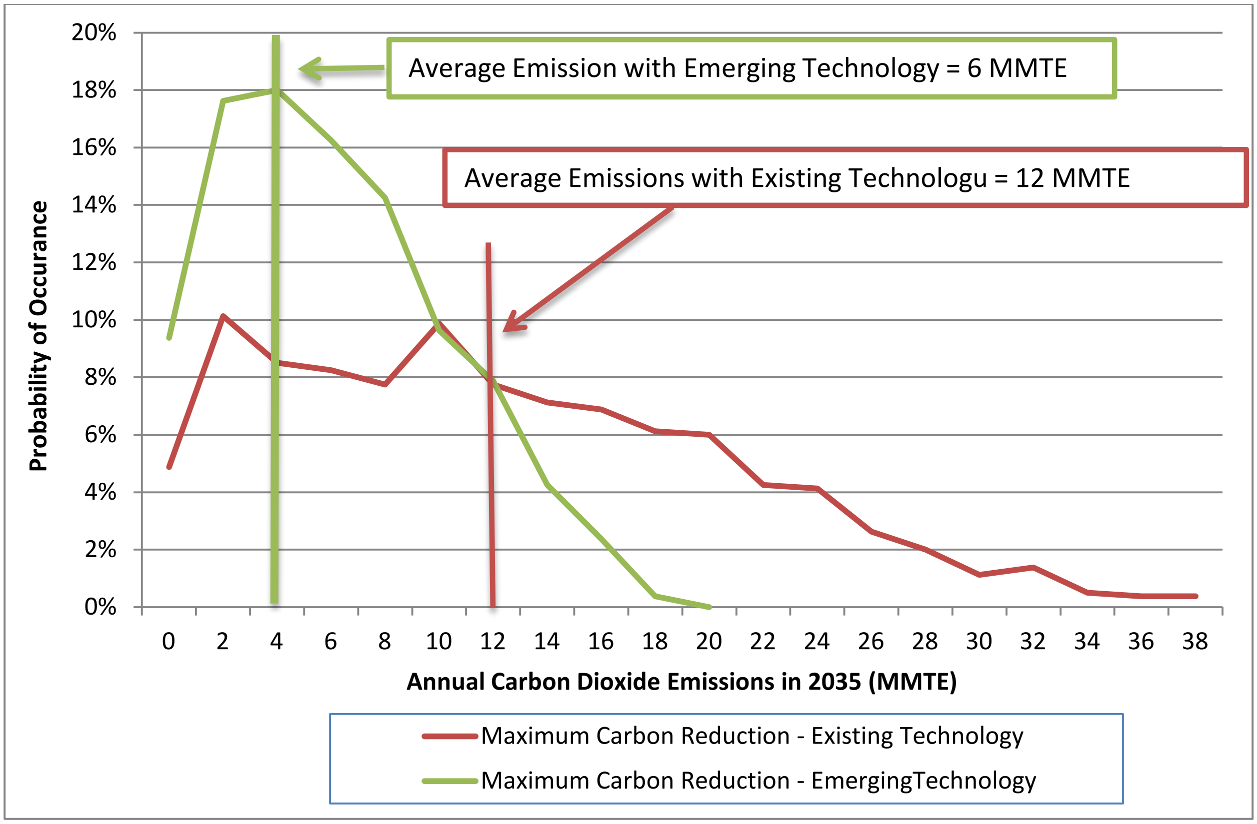
Table 15 - 8: Energy Efficiency Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

Emerging Technology	Regional Potential - 2025			Regional Potential - 2030		
	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)
Additional Advances in Solid-State Lighting	200	400	$0-$30	400	800	$0-$30
CO_2 Heat Pump Water Heater	110	200	$100-150	160	300	$90-140
CO_2 Heat Pump Space Heating	50	160	$130-170	130	350	$110-160
Highly Insulated Dynamic Windows - Commercial	20	130	$500+	35	200	300
Highly Insulated Dynamic Windows - Residential	80	230	$500+	120	350	400
HVAC Controls – Optimized Controls	140	230	$90-120	200	350	$80-110
Evaporative Cooling	50	0*	$100-130	80	0*	$90-120
Total	650	1,350	N/A	1,125	2,350	N/A

Table 15 - 9: Non-Carbon Dioxide Emitting Generating Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

	Utility Scale 48 MW Solar PV Plant – Southern Idaho				**Utility Scale 48 MW Solar PV Plant – Kelso WA**				**Distributed Solar (Residential and Commercial Sectors)**			
	Potential regional installed capacity = 528 MW				Potential regional installed capacity = 1,440 MW				Potential regional installed capacity = 28,100 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)*
2020	12	-	24	$66	9	-	24	$89	340	2	700	$180
2025	12	-	24	$58	9	-	24	$77	1350	6	2800	$170
2030	12	-	24	$51	9	-	24	$68	2880	13	6000	$150
2035	12	-	24	$51	9	-	24	$67	4000	18	8300	$150
*High penetration of distributed solar resources will likely require additional integration cost and distribution system upgrades												

Figure 15 - 13: Distribution of Annual Carbon Dioxide Emissions Under Maximum Carbon Reduction Scenarios With and Without Emerging Technology

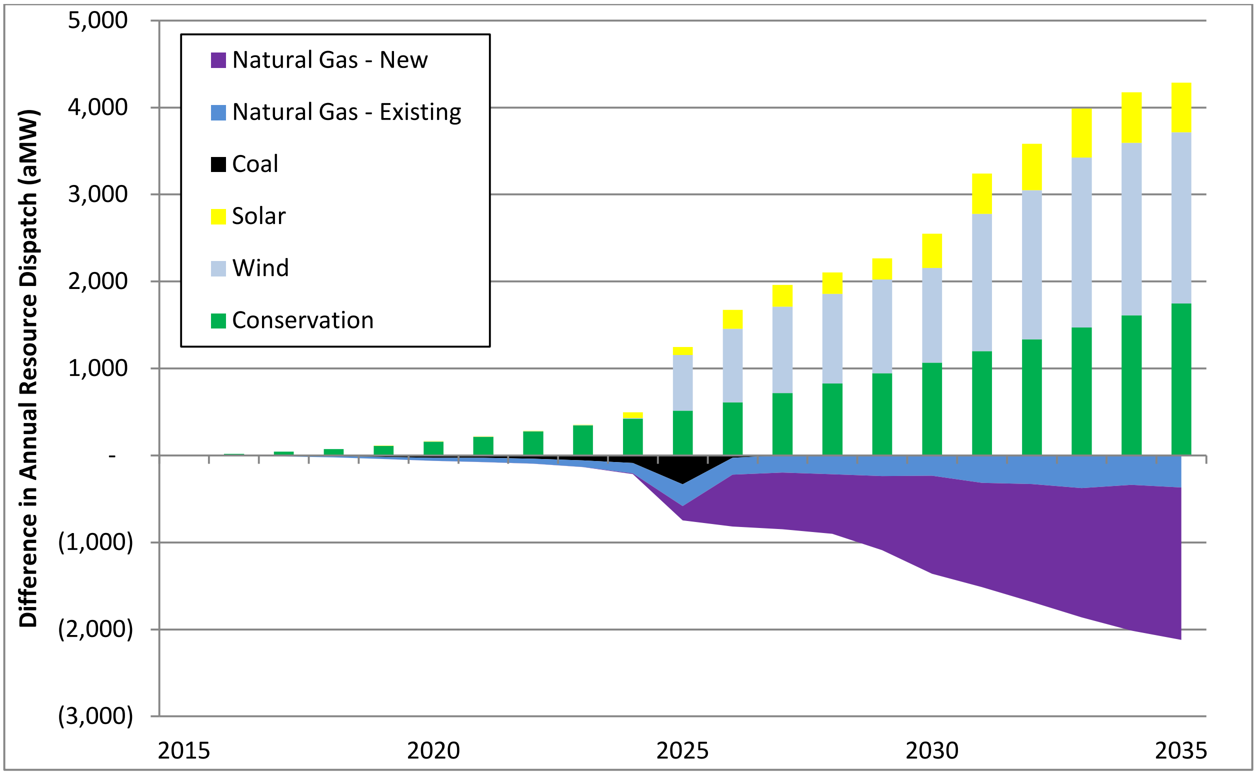


The difference in annual resource dispatch over time between the **Maximum Carbon Reduction – Emerging Technology** scenario and **the Maximum Carbon Reduction – Existing Technology** scenario is shown in Figure 15 -14. As can be observed from Figure 15 - 14 the primary differences is the increased amount of energy efficiency and renewable resources developed (shown by the bars above the origin on the vertical axis) under the emerging technology scenario and less reliance on both existing and new gas-fired generation (shown by the wedges below the origin on the vertical axis). It should be emphasized that under the emerging technology scenario this tradeoff between new natural gas generation and emerging conservation and renewable resource development *is not* based on economics. Rather, their development occurs because new natural gas-fired generation was specifically excluded from consideration under the emerging technology scenario.

Figure 15 - 14 shows that under the **Maximum Carbon Reduction – Emerging Technology** scenario just over 2,000 average megawatts of gas-fired generation must be displaced by approximately 2,500 average megawatts of renewable resources and 1,750 average megawatts of additional energy efficiency. The large difference in the amount of natural gas resources displaced versus the amount of conservation and renewable resources added reflects the limited contribution to supplying winter peak demands provided by solar PV and wind resources.

In order to lower the cost of achieving the carbon emissions reductions in the **Maximum Carbon Reduction - Emerging Technology** scenario and/or to further reduce the power system's carbon emissions requires the development of non-greenhouse gas emitting technologies that can provide both annual energy and winter peak capacity.

Figure 15 - 14: Difference in Annual Resource Dispatch Between Maximum Carbon Reduction – Existing Technology Scenario and Maximum Carbon Reduction – Emerging Technology Scenario



The most promising of these technologies in the Northwest are enhanced geothermal, solar PV with battery storage and small modular nuclear reactors. The potential costs, annual energy, winter and summer peak contribution of these resources are shown in Tables 15 - 10 and 15 - 11.

Both enhanced geothermal and small modular reactors can provide year-round generation and can, within limits, be dispatched based on resource need. However, neither of these technologies, even if proven, is likely to contribute significantly to regional energy needs until post-2025. In contrast, solar PV with battery storage offers more near-term potential for meeting much of the region's summer energy needs as well as supplying more or all of the summer system peak demand. The current cost of such PV systems, however, is not economically competitive with gas-fired generation. See Chapter 11 for a more detailed discussion of these emerging technologies.

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 ton today to about 12 million metric tons, or by nearly 80 percent in 2035. The cost of this resource strategy is approximately $20 billion more than the Existing Policy's least cost resource strategy.

- With development and deployment of 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 by 2035.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.
- Deployment of variable output renewable resources at the scale considered in the **Maximum Carbon Reduction – Emerging Technology** scenario will presents significant power system operational challenges.

Table 15 - 10: Enhance Geothermal and Small Modular Reactor Emerging Technologies' Potential Availability and Cost

	Enhanced Geothermal Systems Potential Installed Capacity by 2035 = 5025 MW				**Small Module Reactors** Potential Installed Capacity by 2035 = 2580 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2025	310	345	345	$102	513	520	520	$95
2030	1,485	1,650	1,650	$73	1,026	1,140	1,140	$88
2035	4,522	5,025	5,025	$58	2,053	2,280	2,280	$81

Table 15 - 11: Utility Scale Solar PV with Battery Storage Emerging Technologies' Potential Availability and Cost

	48 MW Solar PV Plant with 10 MW Battery System – Roseburg OR Regional Potential – Nearly Infinite				**48 MW Solar PV Plant with 10 MW Battery System – Kelso WA** Regional Potential – Nearly Infinite			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2020	10	9	24	$123	9	9	24	$139
2025	10	9	24	$102	9	9	24	$115
2030	10	9	24	$86	9	9	24	$97
2035	10	9	24	$85	9	9	24	$96

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 the final Clean Power Plan (CPP) rules. The "111(d) rule," refers to the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants. The CPP's goal is to reduce national power plant CO2 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. Along with the 111(d) rule, the EPA also issued the final rule under the Clean Air Act section 111(b) for new, as opposed to existing, power plants and the EPA also proposed a federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the CPP requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in CO2 emissions. The eight year interim compliance period is further broken down into three periods, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim emission reduction goals.

Under the EPA's final rules, states may comply by reducing the average carbon emission rate (pounds of CO2 per kilowatt-hour) of all power generating facilities located within their state that are covered by the rule. In the alternative, states may comply by limiting the total emissions (tons of CO2 per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option, EPA has set forth two alternative limits on total CO2 emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach is a better representation of the total carbon footprint of the region's power system and is more fully able to capture the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 15 - 12 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 15 - 12: Pacific Northwest States' Clean Power Plan Final Rule CO2 Emissions Limits[5]

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

[5] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 15 - 8 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically located within regional boundaries defined under the Northwest Power Act[6]. In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's CO2 emissions limits to those specifically covered by the agency's regulations it was necessary to model a sub-set of plants in the region. Table 15 - 13 shows the fuel type, nameplate generating capacity for the total power system modeled by the Council and the nameplate capacity and fuel type of those covered by the EPA's Clean Power Plan regulations modeled for purposes of comparison to the 111(b) and 111(d) limits shown in Table 15 - 12.

Table 15 - 13: Nameplate Capacity of Thermal Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States

Fuel Type	Modeled for Total PNW Power System Emissions Nameplate Capacity (MW)	Modeled Generation Affected by EPA 111(b)/111(d) Emissions Limits (MW)
Total	16,787	12,044
Coal	7,349	4,827
Natural Gas	9,329	7,218
Oil/Other	109	0

Under the Clean Power Plan, 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 15 - 15 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 Clean Power Plan emission limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 15 - 15 shows that all of the scenarios evaluated result in average annual carbon emissions

[6] 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).)

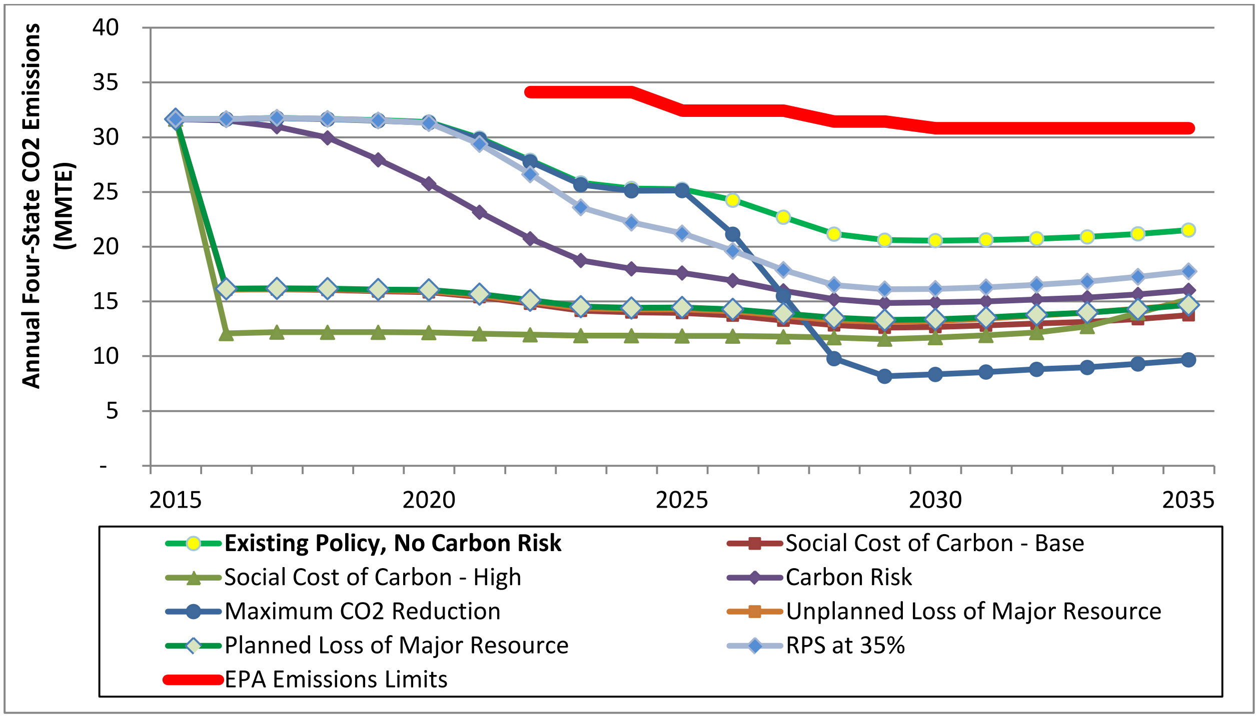
well below the EPA limits for the region. This includes two of the scenarios that were specifically designed to “stress test” whether the region would be able to comply with s the Clean Power Plan’s emission limits if one or more existing non-carbon emitting resources in the region were taken out of service.

In the **Unplanned Loss of a Major Resource** scenario, it was assumed that a single large resource that does not emit carbon dioxide with 1,200 megawatts of nameplate capacity, producing 1,000 average megawatts of energy would randomly and permanently discontinue operation sometime over the next 20 years. Because this scenario was designed to test the vulnerability of the region’s ability to comply with the Clean Power Plan’s emission limits in 2030, it was assumed that there was a 75 percent probability that this resource would discontinue operation by 2030 and a 100 percent probability it would do so by 2035. In the second scenario, the **Planned Loss of a Major Resource**, it was assumed that a total of 1,000 megawatts nameplate capacity producing 855 average megawatts of energy resources that do not emit carbon dioxide were retired by 2030. A review of Figure 15 - 15 shows that under both scenarios the average regional carbon dioxide emissions are well below the EPA’s limits for 2030 and beyond.

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

All of the least cost resource strategies that have their emission levels depicted in Figure 15 - 15 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 are not modeled and would increase regional emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched to meet regional adequacy standards for energy and capacity rather than to serve external markets.

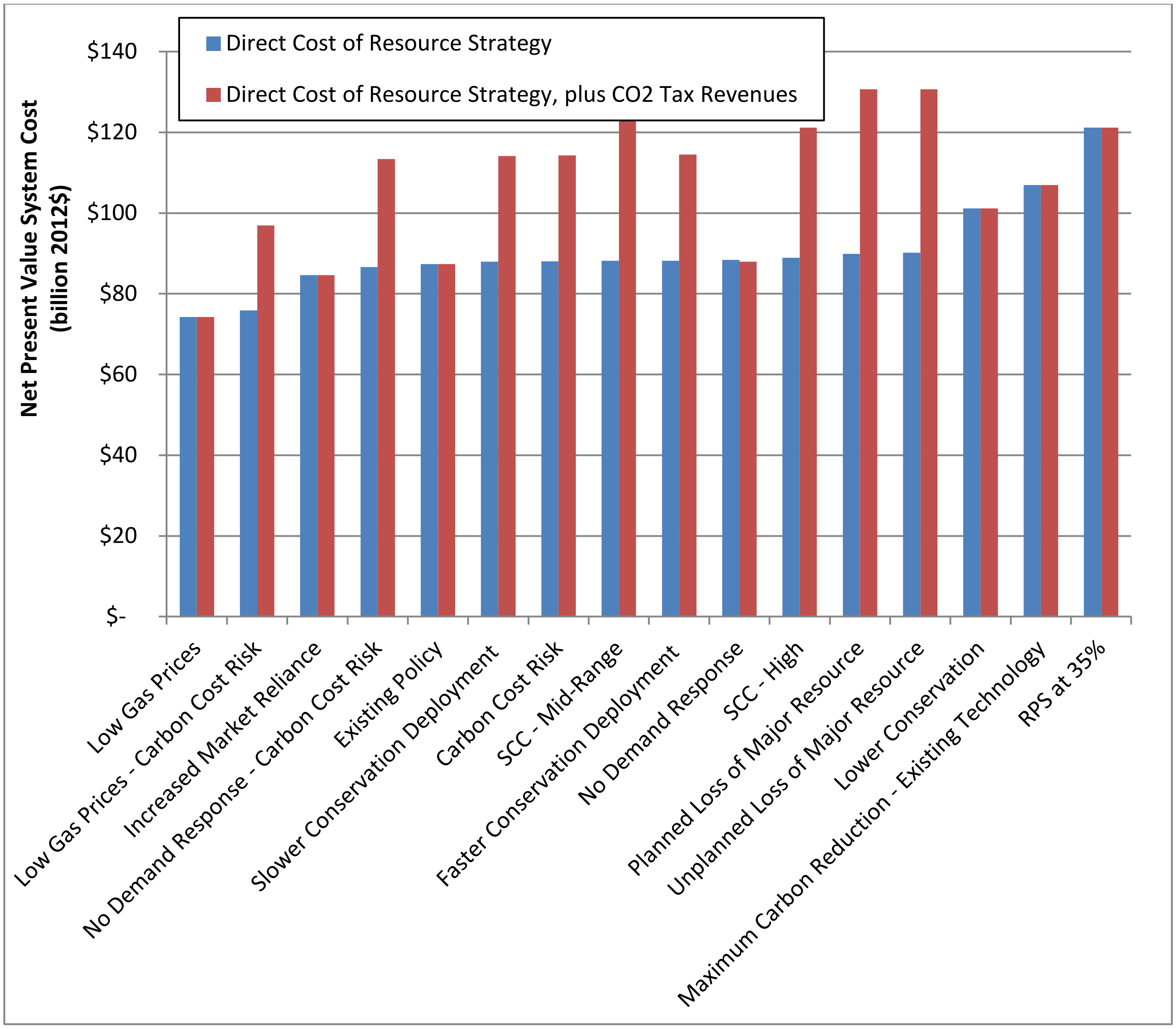
Figure 15 - 15: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by the Clean Power Plan and Located Within Northwest States



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 to identify the strategies that have both low cost and low risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 15 - 16 shows the present value system cost for the principal scenarios evaluated during the development of the Seventh Power Plan. Figure 15 - 16 also shows the present value of power system costs both with and without assumed carbon tax revenues. That is, the scenarios that assumed some form of carbon price include not only the direct cost of building and operating the resource strategy, but also the revenues from carbon dioxide taxes assumed in those scenarios. Of course those scenarios without a carbon price, the **Low Gas Price** and **Existing Policy** scenarios have the same average system cost in both cases.

Figure 15 - 16: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Tax Revenues



Inspection of Figure 15 - 16 shows that, exclusive of carbon costs, the average net present value system cost for the least cost resource strategies across several of the scenarios are quite similar.

Table 15 - 14 shows that only three scenarios (the **Maximum Carbon Reduction – Existing Technology**, **Lower Conservation and RPS at 35%)** have average system costs that differ significantly from the **Existing Policy** scenario. This is due largely to the fact that the components of the least cost resource strategies across the other scenarios are very similar. In the case of the **Maximum Carbon Reduction – Existing Technology** scenario, all of the coal plants that serve the region are assumed to be retired as are existing gas plants 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. Note that under both **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario, 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, the average present value system cost

of these scenarios would likely be much closer to the **Maximum Carbon Reduction – Existing Technology** scenario.

The least cost resource strategy under the **Lower Conservation** scenario develops about 1,200 average megawatts less energy savings and 2,900 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 **Regional 35 Percent RPS** 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.

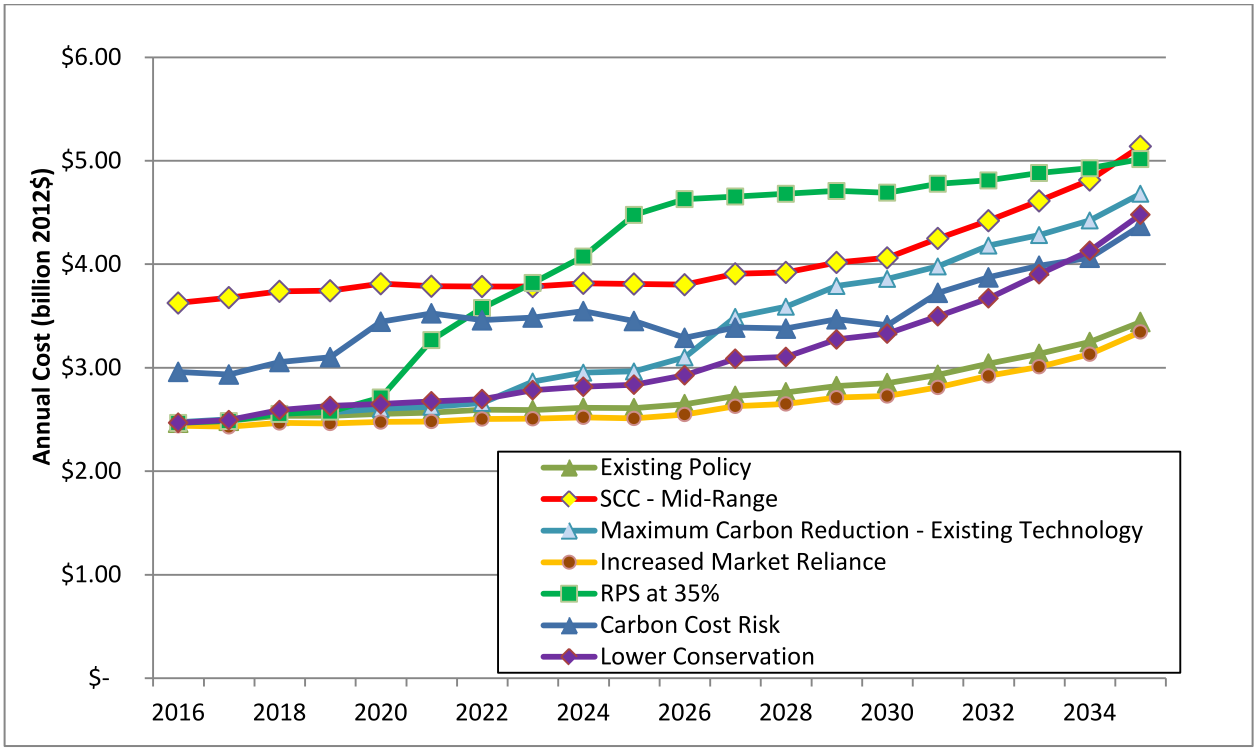
Table 15 - 14: Average Net Present Value System Cost with Carbon Cost and Incremental Cost Compared to Existing Policy, No Carbon Risk Scenario

Scenario	System Cost Without Carbon Tax Revenues (billion 2012$)	Incremental Cost Over Existing Policy Scenario (billion 2012$)
Existing Policy	$87	
Social Cost of Carbon – Mid-Range	$88	$0.8
Social Cost of Carbon – High-Range	$89	$1.5
Carbon Risk	$88	$0.7
Maximum CO2 Reduction – Existing Technology	$107	$19.6
Unplanned Loss of Major Resource	$90	$2.8
Planned Loss of Major Resource	$90	$2.5
Faster Conservation Deployment	$88	$0.8
Slower Conservation Deployment	$88	$0.6
Increased Reliance on External Markets	$85	($2.7)
Regional 35 Percent RPS	$121	$33.9
Lower Conservation – No Carbon Risk	$101	$13.8

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Figure 15 - 17 shows forward-going power system costs for selected scenarios on an annual basis.

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 15 - 17 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the two Social Cost of Carbon scenarios and the Carbon Cost Risk scenario include carbon tax revenues.

Figure 15 - 17: Annual Forward-Going Power System Costs, Including Carbon Costs



A review of Figure 15 - 17 shows that power system costs increase over the forecast period even in the **Existing Policy** scenario due to investments in energy efficiency, demand response, resources needed to comply with existing renewable portfolio standards, and gas-fired generation to meet both load growth and replace capacity lost through announced coal plant retirements. The resource strategies with the highest cost are those that include either carbon cost (the **Social Cost of Carbon** scenarios and **Carbon Cost Risk**) or those that were specifically designed to reduce future carbon emissions (**Maximum CO2 Reduction** – **Existing Technology**, **RPS at 35%**). The **Carbon Risk and Lower Conservation** least cost resource strategies have comparable annual costs towards the end of the planning period. The rapid increase in the annual cost for the least cost resource strategy in the **RPS at 35%** scenario occurring post-2020 results from increased investments in renewable resources beyond current state standards in order to satisfy the higher standard by 2030.

Four of the scenarios assume no carbon regulatory compliance cost or damage costs**: Existing Policy**, **Maximum Carbon Reduction – Existing Technology**, **Lower Conservation** and **RPS at 35%**). Their forward going costs are identical with and without carbon cost. In order to compare the direct cost of the actual resource strategies resulting from carbon pricing policies with these four scenarios, it is necessary to remove the carbon cost from those other scenarios. Figure 15 - 18 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon tax revenues.

Figure 15 - 18: Annual Forward-Going Power System Costs, Excluding Carbon Tax Revenues

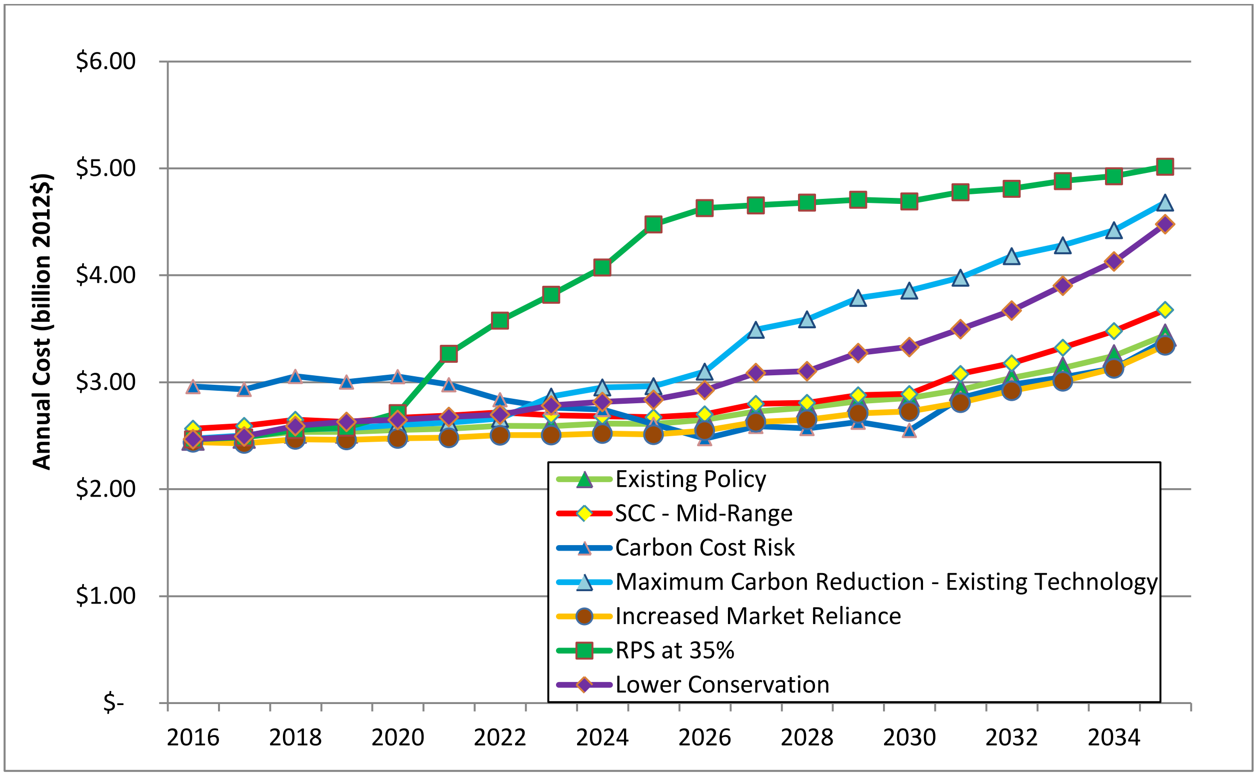


Figure 15 - 18 shows that the **Carbon Cost Risk** and **Increased Market Reliance** scenarios have lower costs post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35%**) and **Maximum Carbon Reduction – Existing Technology** least cost resource strategies. The highest forward going revenue requirement, well above even the **Maximum Carbon Reduction – Existing Technology** scenario's least cost resource strategy is the **RPS at 35%** scenario. 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.

To translate these planning costs to the changes that would likely be experienced by consumers in their rates and bills (or ratepayer costs), existing power system costs need to be included and some costs that are not recovered through utility electric revenues need to be excluded. Figure 15 - 19 shows an index of forecast total utility revenue requirements for the **Existing Policy** and the **Carbon Cost Risk** scenarios in the context of historical levels. For the **Carbon Cost Risk** scenario the higher line of forecasts includes average carbon costs as if they were entirely recovered through electricity revenues. The lower line assumes that revenues from carbon costs are "returned" to consumers by reductions in other taxes or credited directly back on their bills. A review of Figure 15 - 19 reveals that without carbon costs, the **Carbon Cost Risk** scenario results in slightly lower utility revenue requirements than the **Existing Policy** case. This result is due to its slightly higher development of energy efficiency, lower renewable resource development and greater reliance on gas compared to coal generation.

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 15 - 19: Index of Historical and Forecast Utility Revenue Requirements

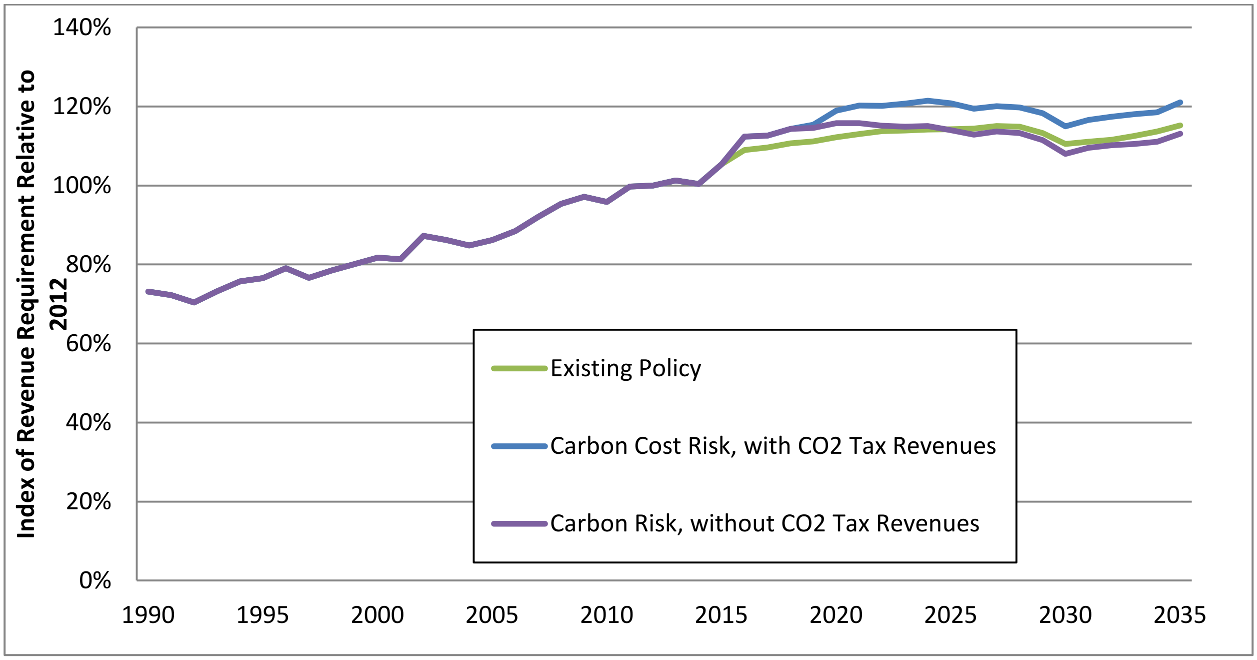
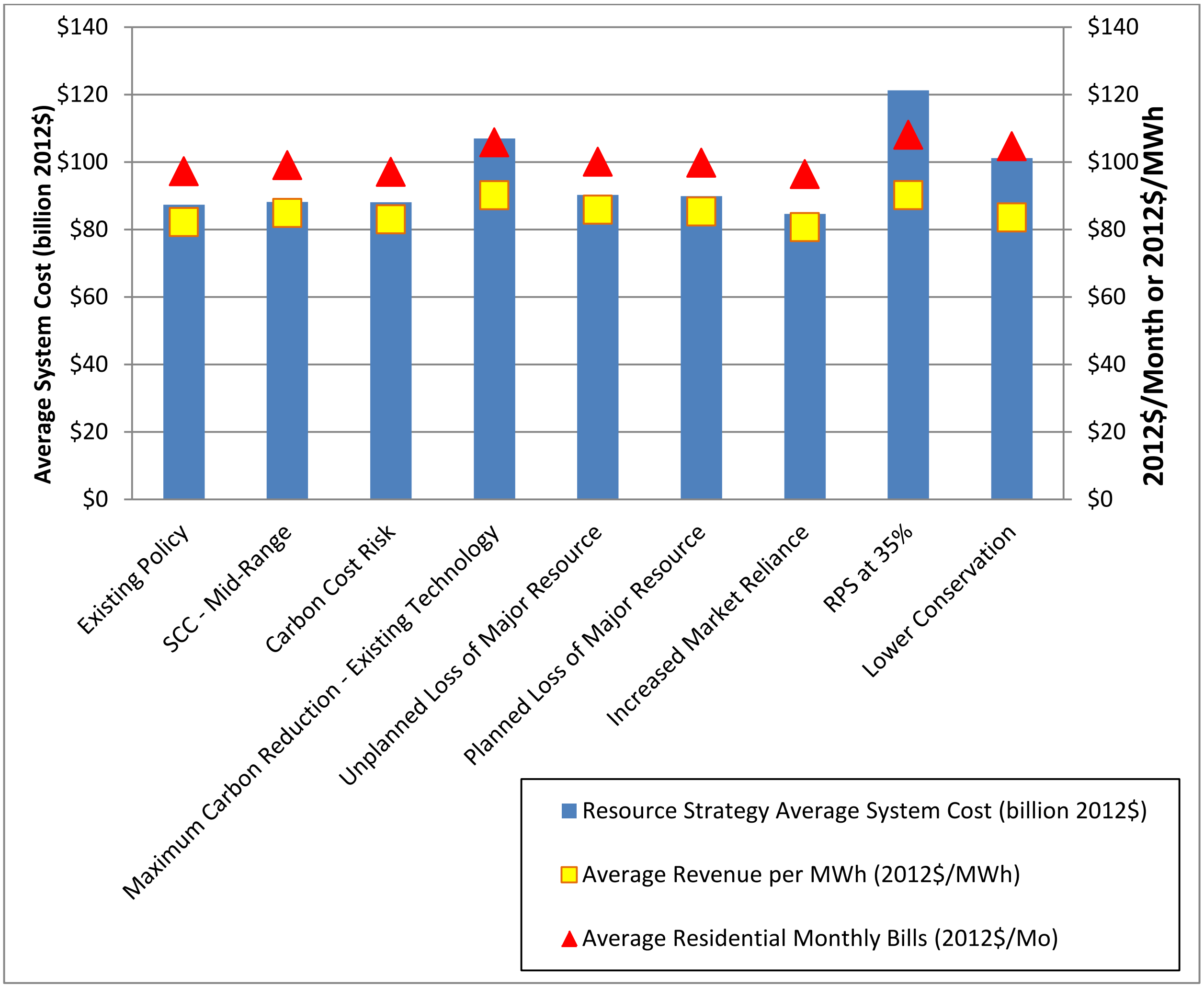


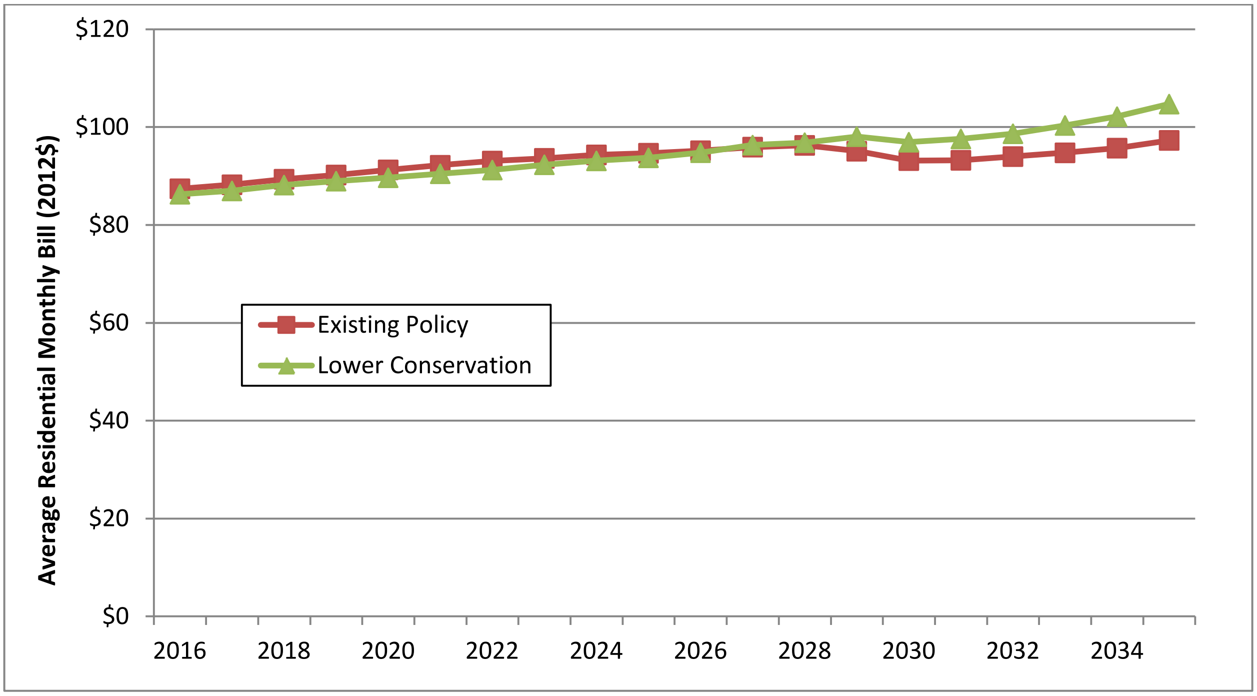
Figure 15 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 15 - 20 by yellow squares are average revenue requirements per megawatt-hour 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 20-year planning period. Both are expressed in real 2012 dollars.

Figure 15 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Tax Revenues



As can be seen in Figure 15 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the **Lower Conservation** scenario. The **Lower Conservation** scenario has an average system cost of $101 billion, compared to the **Existing Policy** resource strategy's $87 billion. Even with nearly a $14 billion higher average system cost the **Lower** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirements 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 $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 15 - 21 illustrates how efficiency improvements lower electricity bills.

Figure 15 - 21: Residential Electricity Bills With and Without Lower Conservation



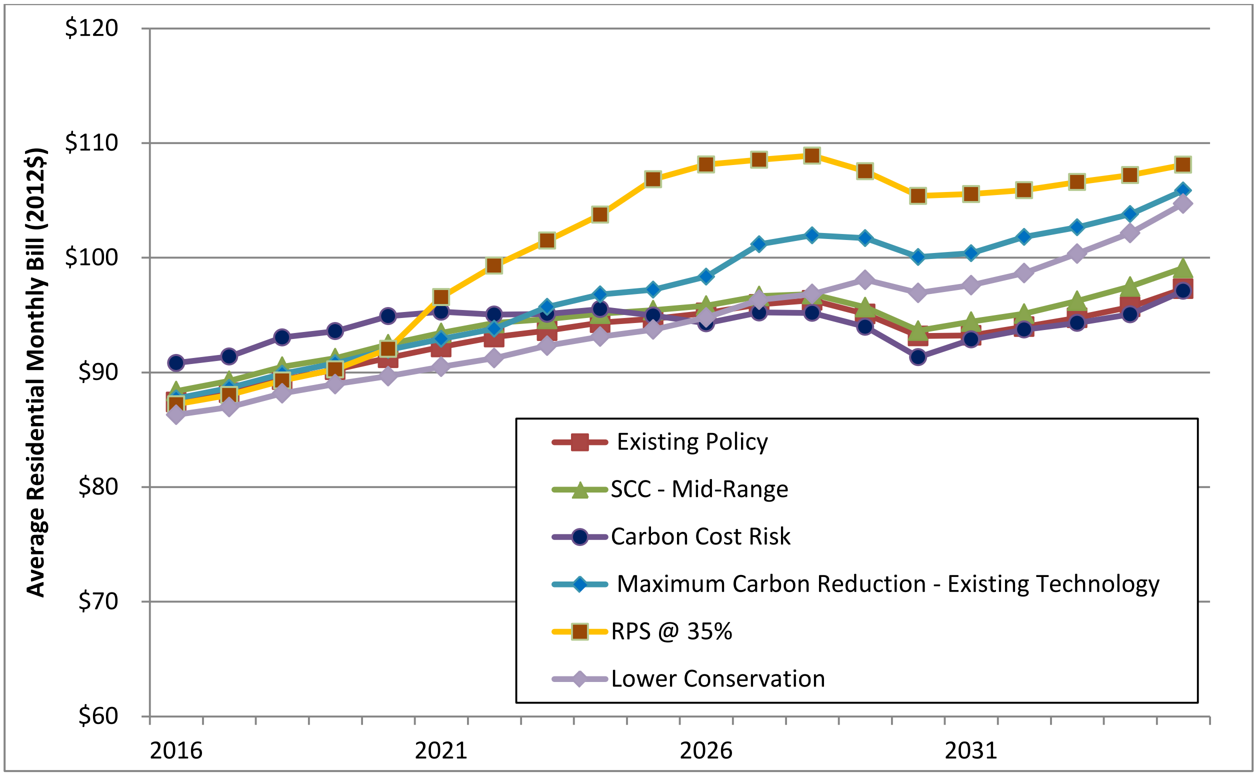
As can be seen from Figure 15 - 21 the **Lower Conservation** least cost resource strategy results in very similar monthly bills compared to the **Existing Policy** least cost resource strategy until about 2028, then monthly bills increase through the remainder of the planning period. The least cost resource strategy under the **Lower Conservation** scenario, develops an average of 1,200 average megawatts fewer energy savings and 2,900 megawatts fewer capacity savings than are developed in the **Existing Policy** scenario. While this reduces the investment in energy efficiency, it increases the investment in new gas and renewable resource generation as well as increases the use of existing coal resources. In aggregate the average system cost of the **Lower Conservation** scenario is nearly $14 billion more than the average system cost of the **Existing Policy** scenario. This additional cost results in roughly equivalent rates, but higher total bills over the 20-year planning period.

The changes in rates and bills are small relative to system-cost changes. The primary reason is that revenue requirements contain a substantial amount of existing costs that do not change among the scenarios. The system costs used in planning exclude existing, or sunk costs and instead include only forward-going costs that could be affected by resource decisions. The effects of carbon reduction on rates and bills are smaller than some participants in the Council's planning process expected. However, this may vary from one utility to the next. One reason is that conservation addresses much of the problem and it is low cost. A second reason is that the region is fortunate to have a low-carbon power system. Most of the carbon emissions come from a relatively small share of the generation that is fired by coal. Since three of the coal plants currently serving the region will be retired by 2026, a substantial amount of the cost of reducing carbon emissions is already internalized into the modeling of the existing system.

Figure 15 - 22 shows monthly residential bills in the **Existing Policy**, **SCC – Mid-Range**, **Carbon Cost Risk**, **Maximum Carbon Reduction – Existing Technology**, **RPS at 35%** and **Lower**

Conservation scenarios. Figure 15 - 23 shows average revenue requirement per megawatt-hour of electricity for these same scenarios. Neither figure includes tax revenues in average revenue requirement or bills.

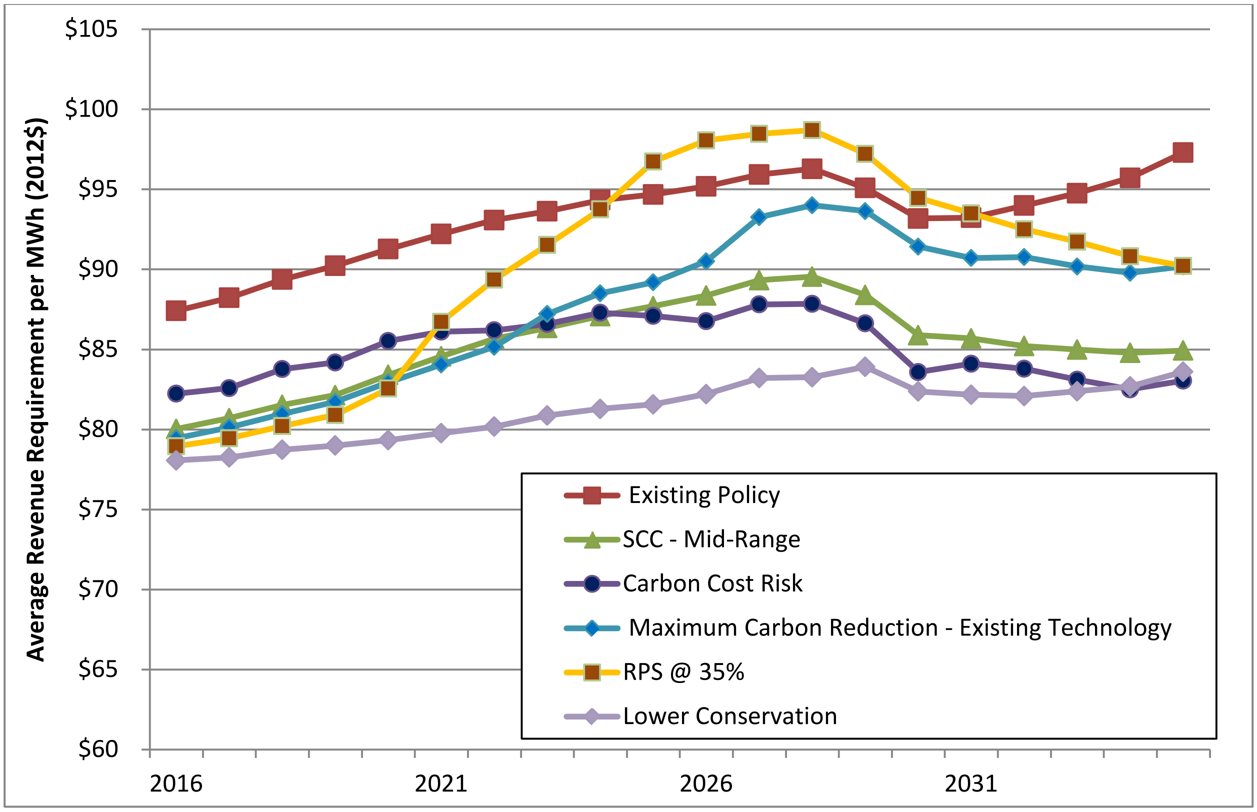
Figure 15 - 22: Monthly Residential Bills Excluding the Cost of Carbon Tax Revenues



A review of Figure 15 - 22 reveals that the highest monthly bills occur under three scenarios; the **RPS @ 35%**, **Maximum Carbon Reduction – Existing Technology** and **Lower Conservation** scenarios. The two carbon reduction policy resource strategies increase average bills due to investments made in new renewable or gas-fired generation to lower regional carbon emissions. In the **Lower Conservation** scenario, average monthly bills are higher than the **Existing Policy** scenario because less conservation is developed; therefore average electricity consumption per household is higher and larger investments in new gas-fired generation are needed to meet demand. The lowest monthly bills occur in the **Carbon Cost Risk**, **SCC – Mid-Range** and **Existing Policy** scenarios.

Figure 15 - 23 shows that the lowest average revenue requirement per megawatt-hour are in the **Lower Conservation**, **Social Cost of Carbon – Mid-Range** and **Carbon Cost Risk** scenarios. In the **Lower Conservation** scenario, the lower average revenue requirement is the result of spreading higher average total power system costs over larger number of megawatt-hours. In the **Social Cost of Carbon – Mid-Range** and **Carbon Cost Risk** scenarios, the lower average revenue requirements per megawatt-hour are the result of lowering average total power system cost even while reducing the number of megawatt-hours sold. Both the **Maximum Carbon Reduction – Existing Technology** and **RPS at 35%** resource strategies have higher average revenue requirements per megawatt-hour, since these two strategies call for the most significant changes in regional resource mix.

Figure 15 - 23: Electricity Average Revenue Requirement per MWh Excluding Carbon Tax Revenues



Scenario Results Summary

Table 15 - 14, on page 15-40 above, presents the principal results of the 20 scenarios and sensitivity studies conducted to support the development of the Seventh Power Plan. Results are presented for the "average" case across all 800 futures tested in the Regional Portfolio Model (RPM). While these averages are useful, readers should keep in mind that the distribution of results across futures can be equally, if not more instructive. A more detailed summary of the RPM's output by scenario is available here:
http://www.nwcouncil.org/energy/powerplan/7/technical