Developing the Plan

Contents

Quantitative analysis and qualitative judgment both play a part in developing the resource plans presented in the IRP.

Risk analysis is at the core of the IRP planning process. We strive to develop an understanding of how different future conditions would affect and influence the lowest reasonable cost mix of resources. We develop forecasts, estimates, and assumptions about key factors that influence portfolio costs: customer demand, power and natural gas prices, and possible CO_2 costs. Then we combine these inputs into scenarios – different "pictures" of the future that reflect a set of integrated assumptions that could occur together. Finally, we use the scenarios to test how portfolio costs and risks respond to changes in economic conditions, environmental legislation, natural gas prices, and energy policy. In some cases, we then isolate a single variable for further study.

The main elements of the analysis are summarized below.[1]

2011 IRP SCENARIOS

The Base Case. All other scenarios are described by how they differ from it.

Low Growth models weaker long-term economic growth than the Base Case.

High Growth models more robust long-term economic growth.

Very Low Gas Price models the impact of very weak long-term gas prices.

Very High Gas Price models a future in which gas prices are extremely high.

Base + CO_2 tests portfolio decisions in a world with moderate CO_2 costs.

Green World tests portfolio decisions in a world with high CO_2 and high gas prices.

The analysis also studied different demand-side resource ramp rates, examined the implications of shuttering the region's coal plants and the impact of investment incentives on renewable resource additions, and compared peaking plant costs and risks with those of CCCT plants.

Qualitative judgments inform the quantitative analysis at every step. The range of estimates and forecasts for key inputs derives from our observations of the current planning environment. The scenarios we develop reflect judgment about the possible challenges PSE and its customers may face over the next 20 years. And our experience in the marketplace informs the evaluation of analysis results.

[1] *For a detailed discussion of how key inputs, scenarios, and sensitivities were developed for this IRP, see Chapter 4, Key Assumptions.*

1. Electric Resource Plan

The 2011 IRP electric resource plan is summarized below and in Figure 2-1.

- The plan is built around Base Case scenario assumptions.
- A 10-year ramp rate for acquiring demand-side resources (DSR) is reflected.
- Renewable resources are acquired just in time to meet RCW 19.285 requirements.
- Peaking plants and transmission plus market power purchases fill remaining need.

A description of the thinking that produced the plan follows.

Figure 2-1
2011 IRP Electric Resource Plan
Cumulative Nameplate Resource Additions to Existing Electric Resources (MW)

	2016	2020	2025	2031
Demand-side resources	423	815	1106	1319
Wind	0	300	300	400
Biomass	0	25	25	50
New transmission + market	0	500	500	500
Peakers	1065	1278	1704	2443

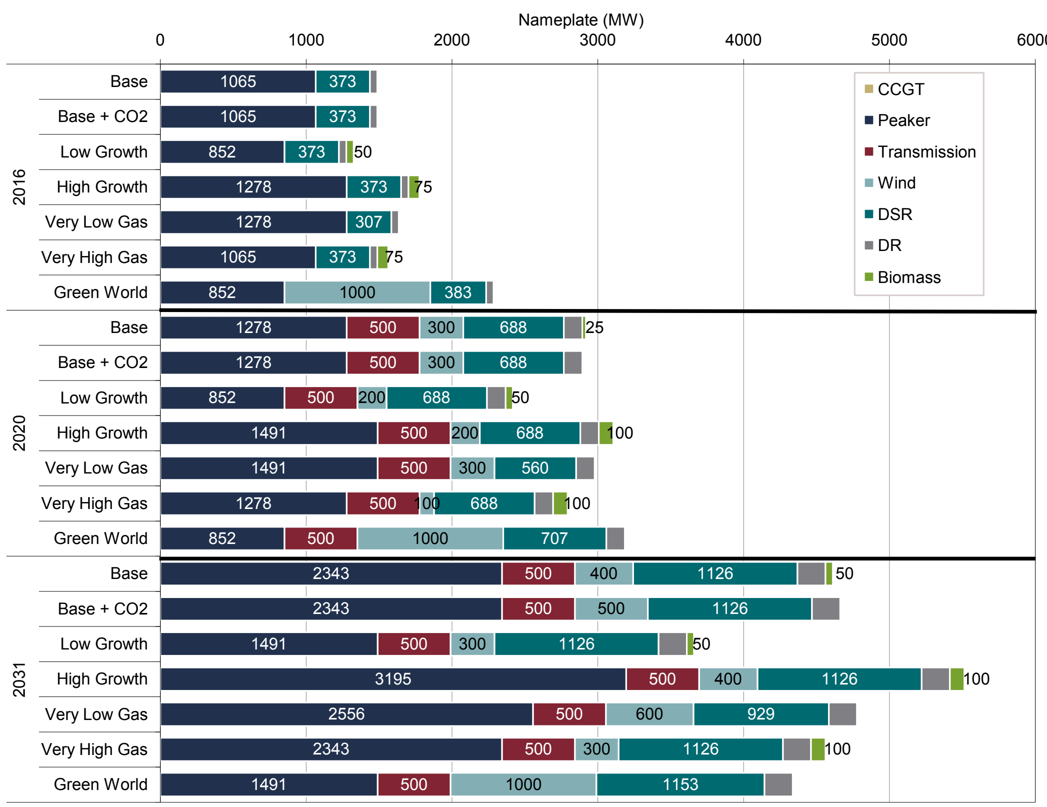
2. Electric Results across Scenarios

Figure 2-2 shows portfolios identified for the seven scenarios analyzed. All portfolios had to be integrated, meaning they had to consider supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (meet customer demands across all hours), and renewable need. Finally, all had to fulfill these requirements at the lowest reasonable cost given the specific scenario.

A high degree of consistency. Least-cost resource plans were very consistent across scenarios. The same amount of conservation is found to be cost effective across nearly all scenarios, renewable resources are added at very similar rates, and additional transmission plus market power purchases and gas-fired, single-cycle peaking generators with oil back-up (peakers) fill remaining resource need.

This is a powerful finding. It means that the wide variety of external market factors modeled in these scenarios will have little impact on the lowest reasonable cost mix of resources. If we find ourselves on the High or Low Growth paths, the number of peaking plants would need to be adjusted up or down; also, a slight rebalancing of wind versus biomass occurs across the different scenarios. But overall, there appears to be little risk in making a resource decision under one market scenario that we would regret if conditions changed. We chose to build the plan around the Base Case scenario.

Figure 2-2
Electric Portfolios by Scenario



Two exceptions appeared among these consistent results: These occurred in the Green World scenario and in the sensitivity that tested shuttering the region's coal plants. Should conditions in the future be as drastically different from the Base Case as those modeled in either of these situations, PSE will have to adjust its portfolio.

Green World

In Green World, CO_2 emission costs rise from $37 per ton in 2012 to $149 per ton in 2031. Gas prices move higher as developers of new generating resources switch from coal to gas to satisfy legal and environmental requirements, thereby increasing demand. And the region's use of gas-fired generation increases as more intermittent, renewable energy generation comes online (wind and solar). We felt it was important to explore the consequences of this scenario even though the high natural gas prices and government-imposed carbon costs modeled appear unrealistic in the current environment. Improving economic conditions and/or increasing pressure due to climate change could shift the picture over the 20-year planning horizon.

Green World has a different planning result than many of the other scenarios. There is a small increase in demand-side resources, but the big change is in wind resources. In Green World, wind energy is cheaper than market, so PSE would minimize costs by replacing market energy with wind to the extent possible to meet energy needs. The output of the analysis is clear: If wind becomes the lowest reasonable cost resource for meeting customers' energy needs, PSE should seek to increase the amount of wind in the portfolio.

Our experience in the marketplace suggests that higher demand for wind generators would probably push the cost up – as we saw between 2005 and 2009. If the region were flooded with utilities and independent power producers building wind farms because they were less expensive than market, development costs would probably exceed those modeled here. Higher wind penetration rates in the region would also probably push integration costs significantly higher than what is assumed in the analysis—including possibly adding resources dedicated to integrating the wind. While long-haul wind was considered in this IRP, it was not modeled as a resource alternative. Based on analysis of the 2009 IRP and 2010 RFP analysis, long-haul would clearly not be cost-competitive with Northwest wind. Perhaps that would be different in a Green World scenario as regional integration costs and supply curves changed. If wind was *still* cheaper than market, PSE would have to adopt an energy related planning standard as a cap, to ensure the company built only what was necessary to meet load. Energy standards for Green World were not investigated in this IRP because the likelihood that such markets will develop is small, and because PSE would have time to develop standards as these conditions developed.

No Northwest Coal

The "No Northwest Coal" sensitivity analyzes how PSE would design a portfolio if policy decisions forced the shutdown of three regional coal plants, Centralia in Washington, Boardman in Oregon, and Colstrip in Montana. Washington State's commitment to reduce emissions to 1990 levels by 2020, and ongoing discussions about the future of Centralia and Boardman led us to judge it prudent to explore the possible consequences of eliminating not just coal resources in this state, but to include the potential for Colstrip to be shut down as well.

Should all three plants be shuttered, PSE would directly lose 677 MW (Megawatts) of base load generation from its share of Colstrip and the region would need to replace several thousands of MW now supplied by Boardman, Centralia, and the rest of Colstrip. In a No Northwest Coal future, it is likely PSE would build or acquire at least enough resources or purchased power agreements to cover the loss of Colstrip. The resources could be CCCTs (combined-cycle combustion turbines), purchased power agreements or some combination of resources that would reduce cost while still meeting customers' needs. All other resource alternatives, including demand-side resources and renewables, would remain unchanged. Should no other parties in the region react to the loss of base load generation, PSE may find it advantageous to develop its own base load resources to meet its needs and possibly even to sell into the market.

That said, a "No Northwest Coal" situation could create several challenges for the region that are not possible to model in the IRP. The location of the additional CCCT plants is difficult to predict for one thing, and location determines transmission impacts. Throughout the region, power flows would change, and transmission and generation operation across the system could turn out to be very different from the way the region operates today. Additionally, market heat rates[2] could be significantly different than what we have seen historically. This will require PSE to perform additional analysis to better

[2] *Market heat rate refers to the spread between the market price of natural gas and the market price of electricity. It is a key factor driving the relative value of peakers and CCCT plants.*

understand how shutting down regional coal plants could affect the behavior of market heat rates.

3. Other Considerations

In addition to scenarios, PSE used sensitivities and other means to isolate certain variables for further study. The following findings influenced thinking on the plan; they are described more fully below.

- Pursuing a more aggressive pace of DSR acquisition than reflected in the 6th Power Plan of the Northwest Power and Conservation Council (NPCC) was found to be cost-effective.
- Financial incentives were found to influence the timing of renewable resource acquisitions, but only as such incentives expired.
- Peakers were found to be more cost effective than CCCT plants given current market conditions.

DSR ramp rates. To investigate ramp rates, PSE had Cadmus develop two detailed alternatives. One was based on a detailed, measure-by-measure analysis of ramp rates used in the NPCC's 6th Power Plan, which generally tended to spread some discretionary measures over 12-16 years. The other was a more aggressive pace of acquisition, acquiring discretionary measures on a 10-year ramp rate. The 10-year ramp rate was found to be more cost effective, as shown in Figure 2-3 below, and therefore is included in the plan.

Figure 2-3
Comparison of PSE vs. NPCC DSR Ramp Rates

Base Scenario	20-yr Expected Incr Rev Req ($Billions)	Bundle	DR
Base (PSE Ramp)	$13.36	E	Yes
Base + 6th Power Plan Ramp	$13.53	E	Yes

Financial incentives for renewable resources. We examined how the extension of federal financial incentives might affect the timing and amount of renewable resource additions by testing several alternatives. In the past, we have observed that expiring deadlines made it cost effective for our customers to accelerate acquisition of these resources ahead of renewable portfolio standard (RPS) timelines. Overall, findings indicated that extension of financial incentives *could* influence timing of renewable resource additions, but it did not increase the amount of additions over RCW 19.285 requirements. Only expiration dates accelerated timing, otherwise additions were made just in time to meet obligations.

Peakers vs. CCCT generating plants. We looked closely at the analysis recommendation of peaking plants over CCCT plants because it differed from prior plans. “Peakers” are gas-fired, single-cycle generating units that operate for short periods of time when demand is greatest. They have low fixed costs and high variable operating costs, so they are not economically dispatched often (meaning it is usually cheaper to buy market power than run the peakers). “CCCTs” are gas-fired, combined-cycle combustion turbines. These cost more to build, but have lower variable costs; because they operate more efficiently, they would be economically dispatched for longer periods of time. Given marketplace conditions in the current planning environment, we found that peakers provided PSE with a way to manage high fixed-cost risks. In contrast, CCCT plants provided a hedge with respect to variable costs, but such a small one that it did not justify the higher cost of construction.

Actual results may vary. Integrated resource plans are a means of examining the potential outcomes over time of different resource decisions within a matrix of varying assumptions and risk scenarios. Markets are dynamic and we use our RFP process and unanticipated market opportunities to create value propositions for our customers. Actual resource additions and portfolio costs will surely vary from those presented in the IRP. With the region surplus on capacity and energy, purchased power agreements backed by existing resources and delivered to PSE’s system may cost less than building additional transmission and/or new peakers. Acquiring distressed generating assets—thermal and/or renewable—for significantly lower cost than assumed in this IRP may be possible. Also, older peaking units may be refurbished rather than retired, reducing the amount of additional capacity needed to serve customers. The acquisition process will build on the lessons learned in the IRP, and utilize updated information on market conditions and new opportunities.

.

4. Gas Resource Plan

For reference, the 2011 IRP gas sales resource plan is summarized in Figure 2-4, below. Following is a description of the thinking that produced the plan.

Figure 2-4
Gas for Sales Resource Plan

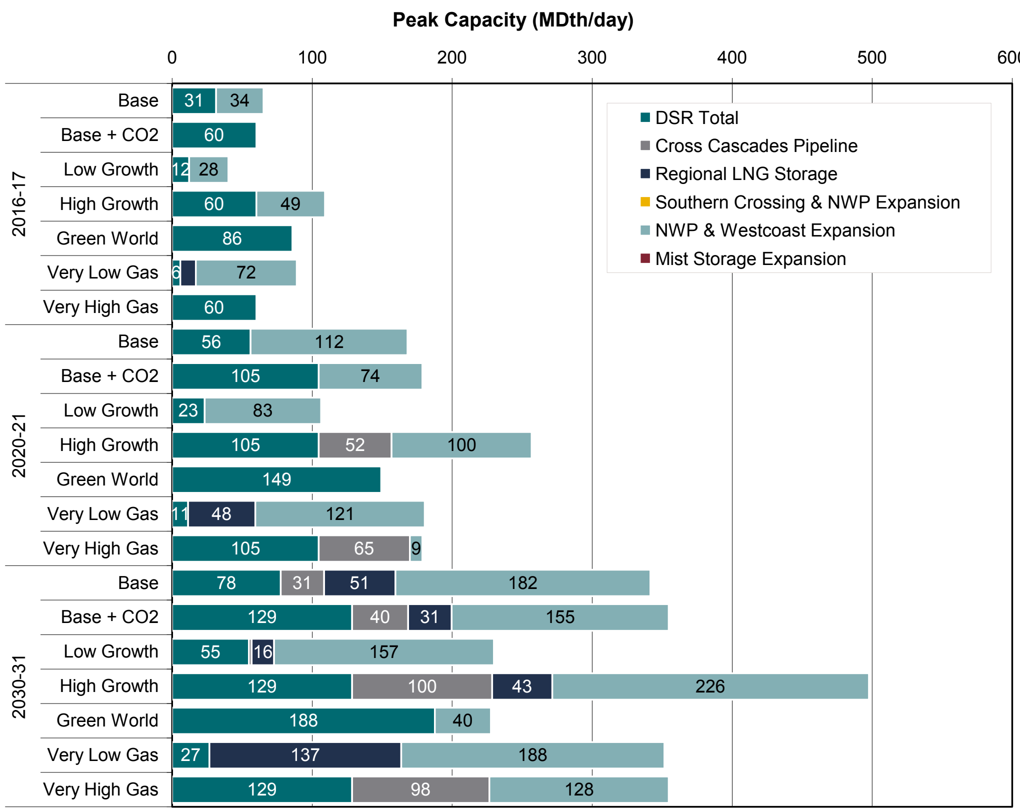
Peak Resource Additions in MDth/day				
	2016-17	2020-21	2024-25	2030-31
Demand-side resources	31	56	65	78
Cross-Cascades pipeline				31
Regional LNG storage			51	51
NWP/Westcoast expansion	34	112	145	182

Overview of Gas Sales Analysis

The gas sales resource plan integrates demand-side resources with supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting needs over the 20-year planning period. The plan identified above is the optimal portfolio produced by the SENDOUT analysis tool for the Base Case scenario. While SENDOUT results are theoretical portfolios based specified inputs and must be reviewed based on judgment and market conditions, in this case the SENDOUT results appear to be both reasonable and achievable. No changes were made to the model results.

As with the electric analysis, the gas sales analysis examined the lowest reasonable cost mix of resources across the range of eight scenarios described at the beginning of this chapter. Figure 2-5 illustrates the lowest reasonable cost mix of resources across those potential future conditions.

Figure 2-5
Gas Sales Portfolios by Scenario



5. Gas Results across Scenarios

As shown in Figure 2-5 there is a relatively big difference in the amount of DSR among the various scenarios. For gas planning, we found that the amount of DSR is quite sensitive to underlying gas prices. The other primary addition selected in all scenarios is increased capacity on the Westcoast pipeline from northern British Columbia (B.C.) to the Sumas hub at the international border, and then on Northwest Pipeline (NWP) from Sumas to PSE's service territory. Limited amounts of regional liquefied natural gas (LNG) storage and cross- Cascades pipeline are selected in the later years. The combination of additional DSR and pipeline capacity on Westcoast and NWP meets all need thru 2020-21.

Demand-side resource additions.

The gas sales resource plan includes about 3,270 MDth of demand-side resource savings by 2017, which translates to peak capacity savings of approximately 31 MDth per day. The annual acquisition rate over the first two years (2012-13) is about 500 MDth per year. This represents a small increase over PSE's current acquisition rate of approximately 450 MDth per year.

Because of the variability in the amount of DSR across the various scenarios we reviewed our acquisition experience over the past few years as well as doing a number of sensitivity tests to confirm that the amounts included in the Base Case scenario are reasonable and lowest cost. Discussions with PSE's Energy Efficiency Services group confirmed that the increase of the acquisition rate from about 450 to 500 MDth per year is achievable. To assess the impact of over- or under-acquiring DSR, we tested the net present value (NPV) impact of acquiring the amount of DSR included the Green World and Very Low Gas Price scenarios in the Base Case. The results are shown in Figure 2-6 below.

Figure 2-6
Impact of DSR Acquisition Level on Base Scenario, NPV Portfolio Costs

DSR Amount	NPV ($ - Billions)
Very Low Gas Price Amount	10.25
Base Amount	10.16
Green World Amount	10.29

Accelerated DSR ramp rates. We also investigated accelerating discretionary DSR measures by ramping them in over the first 10 years rather than over the full 20-year study period. The NPV of portfolio cost was $10.16 billion using the 10-year ramping compared to $10.18 billion for the 20-year ramping. The resource plan reflects the 10-year ramping of the discretionary measures.

SENDOUT's Monte Carlo capability was used to check the robustness of the DSR levels in the Base Case under a wide range of gas prices and loads, and the same amount of DSR was selected in over 95% of the draws.

Based on these results we included the Base Case levels of DSR from the SENDOUT results in the final resource plan.

Westcoast and Northwest pipeline expansion: Northern B.C. gas supply. The gas sales plan calls for a 34 MDth per day expansion of Westcoast/Northwest pipeline capacity by the winter of 2016-17 and further expansions over the planning horizon. The Westcoast/Northwest pipeline expansion alternative was expected since it is the lowest-cost alternative, and provides access to an ample, relatively low cost gas supply in northern B.C. The combination of Westcoast/Northwest pipeline capacity expansion and cost-effective DSR is a robust decision among the various planning scenarios.

The Monte Carlo results indicate that the resource plan amount (112 MDth per day) of this alternative is selected in 77% of the draws.

Regional LNG storage and cross-Cascades capacity.

A relatively small amount of regional LNG storage (51 MDth per day) is included in the resource plan beginning in 2021, and 31 MDth per day of cross-Cascades pipeline capacity is included later in the planning horizon. To achieve "economies of scale," development of either of these projects will require substantial size to be cost effective. For example, a regional LNG storage facility would need deliverability of perhaps 150 MDth per day to be cost effective, and a cross-Cascades pipeline would need a capacity of perhaps 250-300 MDth per day, depending on the specific project. It is unlikely that PSE would proceed with either project without partners. This does not appear to be an immediate concern, since there are other alternatives, and since regional LNG storage and cross-Cascades capacity are not included in the plan for several years.

Alternatives not included. Neither acquisition of capacity at the Mist storage facility nor participation in an expansion of the Southern Crossing pipeline was selected in any of the scenarios. The cost of the Southern Crossing alternative is relatively high; the use of multiple of pipelines would result in high transportation costs that are not expected to be offset by lower gas prices at the AECO supply hub.

While not included in the resource plan, leasing capacity from an expansion at the Mist gas storage facility does have some attractive features. It is located in Northwestern Oregon relatively close to PSE's service territory and is an existing, proven alternative. If the operating characteristics prove to be a good match for PSE's needs and if a cost-effective redelivery service can be developed it may be an attractive alternative in the future. PSE will continue to investigate this alternative.