Appendix J: The Regional Portfolio Model

INTRODUCTION AND SUMMARY

This appendix describes assumptions and methods of the Regional Portfolio Model (RPM). For the most part, each section stands alone and can be read in any sequence. Where this is not the case, the section will point to supporting material.

The description here is limited to changes since the Fifth Power Plan. Chapters 6, **Risk Assessment and Uncertainty**[1], and 7, **Portfolio Analysis and Recommended Plan**[2], of the Fifth Power Plan explain broader concepts, like the selection of resource portfolios. Appendices L,

1 http://www.nwcouncil.org/energy/powerplan/5/%2806%29%20Risk%20Section.pdf
2 http://www.nwcouncil.org/energy/powerplan/5/%2807%29%20Portfolio%20Analysis.pdf

Description of the Portfolio Model[3], and P, **Treatment of Uncertainty and Risk**[4], of the Fifth Power Plan explain the model's features in detail. This appendix will not repeat that material.

Instead, the appendix begins with the more apparent changes to the model, like the shift in cost and risk since the Fifth Plan. It then outlines key changes to the logic. A study of uncertainty highlights the main sources of economic risk to the region. Some thoughts about the modeling of risk conclude the appendix.

CHANGES SINCE THE FIFTH PLAN

This section presents an overview of the model and data changes responsible for cost and risk shifts since the last Council power plan. The changes appear as a sequence of model revisions. This background helps explain differences appearing in later sections.

Overview of Data and Model Changes

Modeling for the Sixth Power Plan began in February 2008. Staff assembled data for power prices and loads, fuel prices, and existing power plants. The model had not been used since the Fifth Power Plan. This exercise was to shake out problems and provide an early look at where the preferred resource portfolio might be headed.

These results were presented at the April 16, 2008, Power Committee meeting in Whitefish, Montana[5]. They resemble the Council's final resource plan. The early estimate of conservation potential, however, was much less than that which appears in the final plan.

Between February 2008 and January 2010, Council staff created thirteen renditions of the model. Each rendition has fixed data assumptions and logic. With each model, staff performed as many as 27 distinct studies or "scenarios." These studies examined questions raised by Council Members or staff. The studies typically involved changing a single assumption and observing the effect on cost, risk, and carbon emissions. In all, there have been over 280 separate studies, all but 20 of those done since January 2009.

Staff also created reports for each study to examine changes and provide reasoning. Two of these reports became routine. One lists the thousands of plans that the model examined and identifies the efficient frontier. The other illustrates the response of the least-risk plan to changing futures. They often go by the names of the "feasibility space" report and the "spinner graph."[6] Additional studies and reports are occasionally required to troubleshoot odd results or answer new questions.

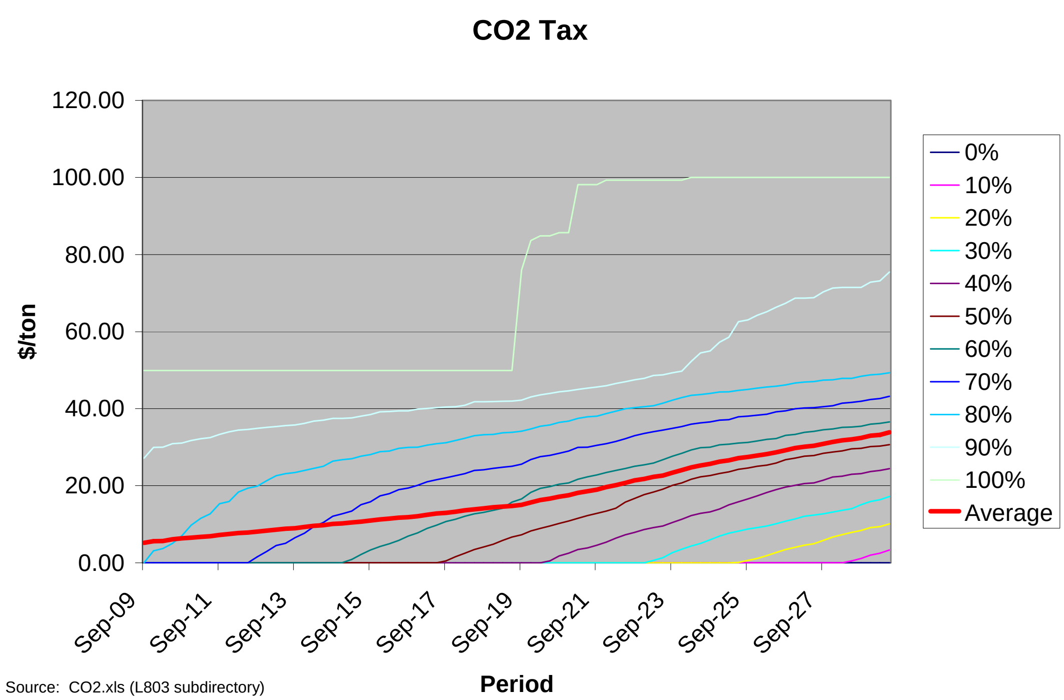
Model L801, run in late February 2008, reflects the data changes since the Fifth Power Plan. The model used for the final Fifth Power Plan is L28. The only difference in L801 logic from that of L28 is in the selection of the energy adequacy target level and in the test of economic value. The model uses the test of economic value to decide whether to proceed with building power plants.

3 http://www.nwcouncil.org/energy/powerplan/5/Appendix%20L%20%28Portfolio%20Model%29.pdf
4 http://www.nwcouncil.org/energy/powerplan/5/AppendixP.pdf
5 http://www.nwcouncil.org/news/2008/04/p3.pdf
6 The report for the final Carbon Risk scenario feasibility space is available at http://www.nwcouncil.org/dropbox/Analysis%20of%20Optimization%20Run_L813vL811.zip . References to web links for several spinner graphs appear in the section, Illustration with Selected Futures, below. Other reports are available upon request.

Most of the L801 input data changed, however. The CO_2 penalty uncertainty increased in magnitude and likelihood. Much like the fifth plan, the CO_2 penalty increases in steps, although the steps became $50 per ton and $100 per ton, instead of the $15 per ton and $30 per ton used in the Fifth Power Plan. The chance of seeing a penalty increased from 66 percent to over 90 percent.

Models L802 and L803 again changed the CO_2 penalty, as well as other assumptions. Staff review served as the basis for these changes. The distribution of carbon penalty appears in Figure J-1. The effects of changes in major assumptions appear in Table J-1. The actual total change differs from the sum of individual changes because the effects do not add directly. The results from model L803 are the basis of the April 16, 2008, Power Committee report.

Figure J-1: Carbon Penalty in L803 (April 2008)



The next big change to the cost and risk of the model came with an end-effect adjustment for carbon penalty. This is the “perpetuity adjustment.” The adjustment, introduced in July 2008 with L804, resulted in an increase of both cost and risk by a factor of three to four. (Figure J-3 in the next section shows the resulting shift in cost and risk.) The section **Perpetuity Factor and End Effects** in this appendix describes the adjustment in detail.

Table J-1: Sensitivity of L803 Average Cost to Various Factors

Fifth Power Plan without perpetuity	**24,059**
L803 plan NG price	**24,560**
L803 plan electricity price	**23,976**
L803 plan Loads	**39,715**
L803 CO2 penalty	**28,539**
All four L803 changes	**49,320**
Actual L803 Least-risk case	**41,364**

source: L811mini for illustrations L803.xls

Model L806 began service in early February 2009. It had what staff intended to be all the data and logic changes for the final portfolio recommendation. The original schedule called for adoption of the draft plan in April 2009. An intermediate version of the model, L805, was really a "restore point" for the model. Model L805 is a "known good" version of the model, before the addition of major changes to cost logic. The version L806 also has the first careful update to energy loads, resource descriptions, and fuel price data. It has the first model of RPS resources. Unfortunately, the schedule for the plan did not allow for a careful review of these extensive changes. Errors were introduced that were not discovered and corrected until version L810.

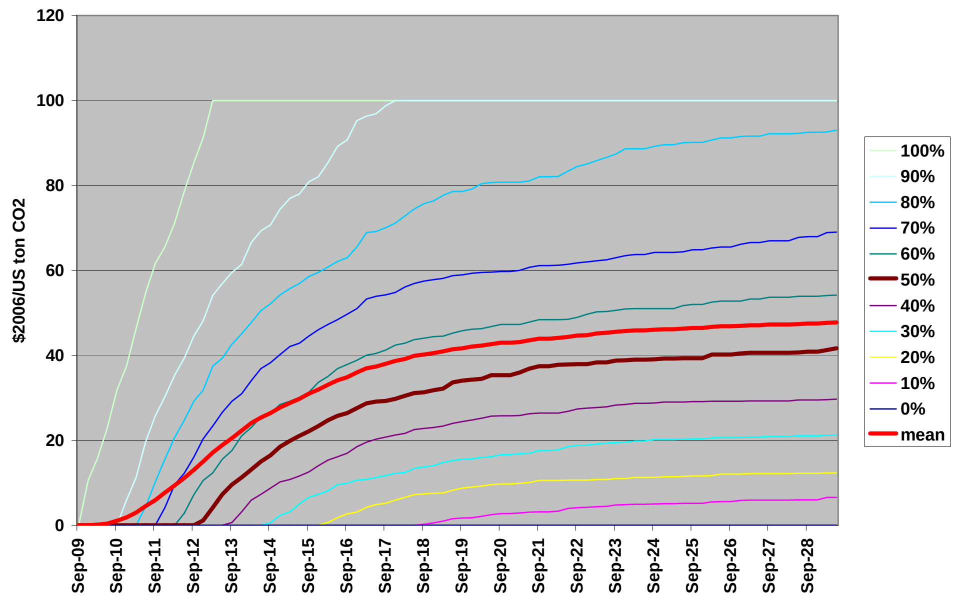
Models L807, L808, and L809 make small improvements to the code and data. The energy adequacy target moves about 2,500 average megawatts, but with little effect on cost and risk. L809 extends the hydrogeneration data to the 70-year record, but it is determined later that the energy for hydro independents is missing in about 20 percent of the hydro conditions.[7] This problem is corrected in L811.

L810 contains corrections to the problems mentioned above. A staff audit of logic and data revealed the problems, using new tools designed for that purpose. L810 also has new load data. The load forecast increased in the near term by almost 4,000 megawatts on peak in the winter. There was also a 3000 average megawatts energy decrease by the end of the study. These load forecast changes reduced the NPV cost of the system by $70 billion.

L811 is the basis for the draft plan. Besides correcting the hydrogeneration data, this version has a new CO2 penalty distribution. The expected arrival of some kind of carbon penalty is earlier in the study period. The distribution appears in Figure J-2.

7 Hydro independents are hydrogeneration units that are not coordinated as part of the Pacific Northwest Coordination Agreement (PNCA).

Figure J-2: Deciles for Carbon Penalty



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

Model L813 is the version used to analyze the scenarios in the final plan. Model L812 uses a new perpetuity adjustment that had some problems of its own. Fixing the perpetuity adjustment gave us L813. This appendix describes these issues and changes in the section, ***Perpetuity Factor and End Effects***.

Model L812, however, contains all of the other model and data changes for the final plan. The more prominent of the changes for the final plan were:

- ✓ new RPS logic,
- ✓ removal of forced-in buy-back demand response capacity,
- ✓ new performance uncertainty logic for conservation,
- ✓ revised discount rate,
- ✓ new load forecast,
- ✓ new fuel and electricity price forecasts, and
- ✓ revised existing resource data

This concludes the description of data and logic changes. The next section summaries the resulting changes in cost and risk.

Sources of Shifts in the Feasibility Space

Figure J-3 shows how cost and risk have moved since the Fifth Power Plan The Fifth Power Plan resource portfolio model is labeled L28. The points are the cost and risk of the *least-risk plan* from each model-version base case.

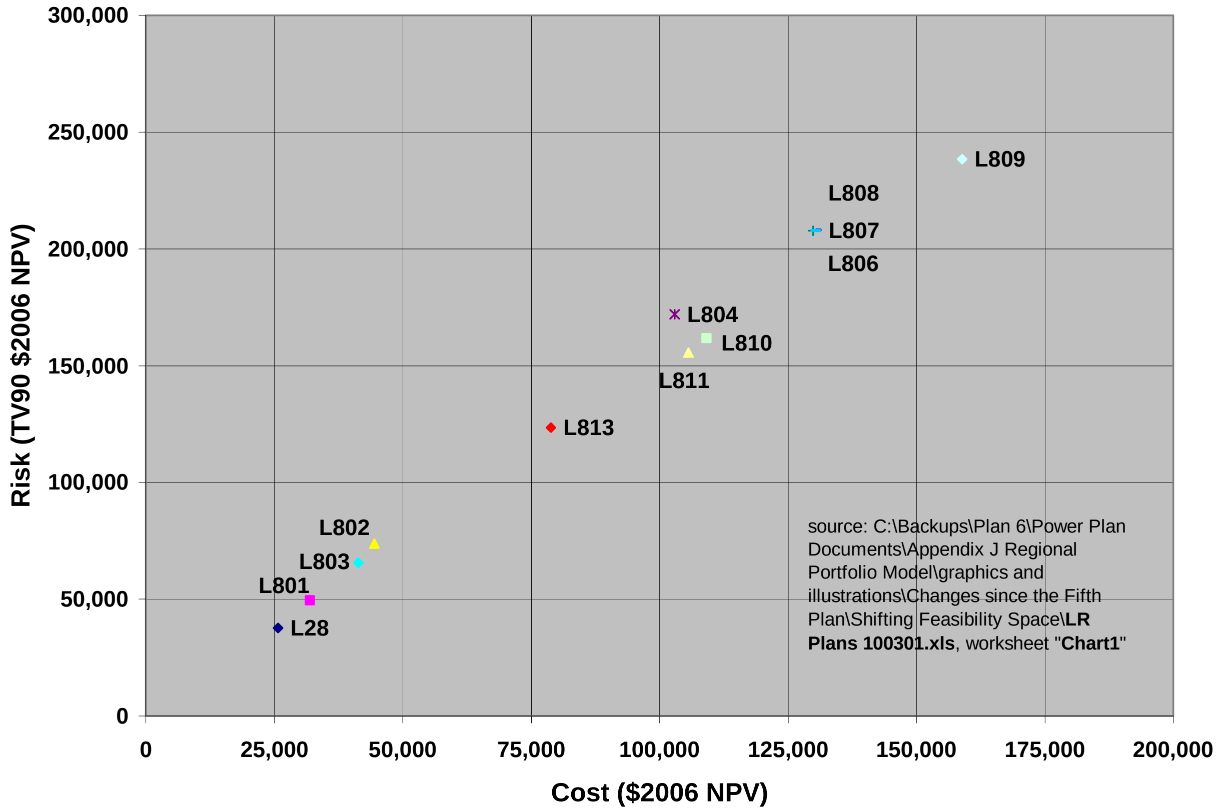
Costs and risk are subject to many factors. The choice of assumptions to be treated as uncertainties and the scale of uncertainty both have a bearing on overall cost and risk. The expected value of each assumption also affects cost and $TailVaR_{90}$ risk.

The first three versions of the model, L801 through L803, capture data changes since the Fifth Power Plan. As mentioned above, Fifth Power Plan uses $15 per ton and $30 per ton for the carbon penalty. Here, the cap is lifted to $100 per ton of CO_2. The distribution appears in Figure J-2. Costs and risks increase about 70 percent to 41.4 billion cost and 65.5 billion risk from the Fifth Plan levels of $24.5 billion expected cost and $35.9 billion risk. Without a more study, it is hard to say how much each change accounts for the cost and risk differences. The decrease from L802 to L803 seems to be due primarily to limiting the carbon penalty to $50 per ton of CO_2 until the second half of the study.

A simplified version of the model provides a way to perform sensitivity analysis. Instead of futures, the simplified version uses expected values for load growth, wholesale electricity and natural gas price, carbon penalty, and so forth. This model shows us the sensitivity of costs to changes in assumptions without the "noise" present in individual futures. Table J-1 indicates that the change in load forecast contributed the most to cost change between L28 and L803.

With the new perpetuity factor in L804, costs increased by 150 percent. At first glance, this increase seems too large. Consider an even stream of cash flows over 20 years contrasted with the same cash flows taken to perpetuity. At five percent, the former would have a net present value (NPV) that is 55 percent of the latter's. The L804 model's perpetuity adjustment is applied, however, only to costs subsequent to the arrival of carbon penalty. The sample of costs used by this adjustment will typically be much higher than those prior to the arrival of the carbon penalty. Consequently, the adjustment will typically be much larger than one based on average costs over the study.

Figure J-3: Evolution of the Feasibility Space



The model L806 reflects the first thorough data review since the Fifth plan. The cost data for models L806 through L809, however, is suspect for the reasons described in the previous section. The values for model L810 are reliable, however. The very large drop in costs between L809 and L810 is due primarily to a change in the load forecast.

Average cost and risk did not change much between L810 and L811. This is true despite many changes in data and code, including a new carbon penalty distribution illustrated in Figure J-2. The year in which there would be a 50:50 chance of a carbon dioxide penalty moved to 2012 from 2019.

In L813, cost and risk falls again. The model uses lower natural gas prices and the loads are lower in the middle-term of the study. The lower load forecast stems from recognition of the effects of the recent economic recession. By the end of the study, loads have recovered.

The Reasons for Increased Conservation

The model finds large amounts of conservation cost effective.   The cost of some of the conservation is above long-term wholesale power market price (“electricity price”, “power price” or “market price”). Many utilities use this price as a measure of cost effectiveness. They apply it not only of conservation but to all resources. They do so because it can be viewed as the utility’s avoided cost. This section explains why the cost effectiveness for conservation can be higher than the wholesale power market price.

First, it is helpful to review how the model decides to acquire conservation. The model uses a decision criterion ("criterion"), as this section explains. There are two parts to the criterion, and they work in different ways. The two parts are the "adjusted market price" and the market adder.

In each period of each future, the model buys conservation from a supply curve up to the criterion value. The supply curve is like a stack of conservation programs, sorted by price. Programs can have different sizes (reductions in electricity use) as well as different prices. There are separate supply curves for lost opportunity and discretionary conservation. The real levelized cost for each program acquired is added to the cost of conservation already acquired.

The adjusted market price reflects considerations unique to valuing conservation. The adjusted market price, for example, weights market prices according to the *distribution* of energy reductions. It also averages market prices over recent history. Averaged market prices stand in for forecasts of long-term market price. Views of the long-term market price tend to follow spot prices and other recent news. They change more slowly, however, just like an average. The decision point also lags the averaging period by a year. Utility budget cycles and decisions give rise to the lag effect. Another difference with market price is the ratchet mechanism used for lost opportunity conservation. The ratchet comes from the nature of codes, laws, and standards, which govern much lost opportunity conservation acquisition. That is, once adopted, laws and codes are rarely reversed.

The market adder is the second factor controlling how the model acquires conservation. As the name suggests, this value is added to the adjusted market price to determine how far up the conservation supply curve to go.

The market adder is one of the elements of a plan, and the model experiments with the value of the adder to reduce cost at each level of risk. The model tries a range of adders, from negative values to as high as $100 per megawatt-hour. Of course, the model is also trying different combinations of other generation resources as it does so. The market adder for plans on the efficient frontier is therefore the results of the model's search process.

One way to understand how factors affect conservation development is to begin with the simple model described in the preceding section. Adding factors one at a time gives us an idea of their relative importance. Because the order of the additions matters, however, some care is necessary in interpreting the results.

The starting point is replacing each uncertainty with a deterministic forecast. Using the Council's adopted electricity price forecast leads to about 4,088 average megawatts of conservation[8]. The electricity price forecast used for this initial estimate assumes no carbon penalty.

The effect of changes to the model depends on the order in which the changes are made. This description follows one path. Table J-2 contains the result of studies using the various models. It shows how applying the changes in a different order would change the effect.

Stochastic variation in electricity price, assuming no carbon penalty, adds 389 average megawatts, bringing the total to 4,477 average megawatts. This variation is the result of uncertainty and

8 …\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation\Copy of L813miniCnsv01 100301 step 00.xls

variation in natural gas price and the construction costs for power plants. It is also due to hydro generation variability, load growth excursions, and many other factors.

Stochastic variation increases acquisition for several reasons. Discretionary conservation has a single supply curve for the entire study. The supply, once accessed, is not restored. Variation in electricity price drives the decision criterion higher earlier than otherwise. The last high water mark, so to speak, is the level at the end of the study. Lost opportunity conservation has a similar ratchet mechanism in its criterion, as described earlier.

Carbon penalty uncertainty moves the wholesale market electricity price up and, consequently, moves up the cost effectiveness threshold for conservation. Introducing the carbon penalty uncertainty increases conservation energy by 470 average megawatts, to 4,947 average megawatts, by the end of the study. The model handles the representation carbon penalty directly. It is therefore possible to cull the contribution from this source of uncertainty from the others.

Finally, we have the effect of market price adders. The adders increase acquisition by 1,011 average megawatts, to 5,958 average megawatts. The adders in the least-risk resource portfolio from the Carbon Risk scenario are different for lost opportunity and discretionary conservation. The former gets a $50 per megawatt-hour adder; the latter garners an $80 per megawatt-hour adder.

The results are summarized in Table J-2. It may be useful to see the effect if discretionary conservation got the same $50 per megawatt-hour adder as lost opportunity conservation. This situation is included among the studies presented here.

Table J-2: Conservation Acquisition Factors

Conservation Acquisition by End of Study	**Carbon Penalty**	**LO market adder**	**NLO market adder**	**Lost Opportunity** MWa	**Lost Opportunity** average cost $/MWh	**Discretionary** MWa	**Discretionary** average cost $/MWh	**Total** MWa	**Total** average cost $/MWh	**Reference**
Deterministic models										
base case	N	0	0	**1,835**	**11.40**	**2,253**	**23.25**	**4,008**	**17.93**	**1**
average carbon penalty	Y	0	0	**2,180**	**16.65**	**2,479**	**26.01**	**4,660**	**21.63**	**2**
equal adders	N	50	50	**2,854**	**28.22**	**2,584**	**28.16**	**5,438**	**28.19**	**3**
final plan adders	N	50	80	**2,854**	**28.22**	**2,727**	**32.05**	**5,582**	**30.09**	**3**
average carbon penalty + equal adders	Y	50	50	**3,037**	**32.28**	**2,719**	**31.78**	**5,755**	**32.05**	**3**
average carbon penalty + final plan adders	Y	50	80	**3,037**	**32.28**	**2,812**	**35.08**	**5,849**	**33.63**	**3**
Stochastic models										
base case	N	0	0	**2,072**	**15.30**	**2,405**	**25.40**	**4,477**	**20.90**	**4**
carbon penalty	Y	0	0	**2,395**	**21.30**	**2,552**	**28.10**	**4,947**	**24.90**	**5**
equal adders	N	50	50	**2,963**	**30.60**	**2,672**	**30.70**	**5,635**	**30.60**	**4**
final plan adders	N	50	80	**2,963**	**30.60**	**2,787**	**34.30**	**5,750**	**32.40**	**4**
carbon penalty + equal adders	Y	50	50	**3,092**	**33.70**	**2,767**	**33.80**	**5,859**	**33.80**	**5**
carbon penalty + final plan adders	Y	50	80	**3,092**	**33.70**	**2,867**	**37.69**	**5,958**	**35.63**	**6**

The results of the stochastic models are averages over 750 futures.

1 C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**Copy of L813miniCnsv01 100301 step 00.xls**

2 loc. cit., **Copy of L813miniCnsv01 100301 step 01.xls**

3 loc. cit., **Copy of L813miniCnsv01 100301 step 02.xls**

4 source: … \Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**L813_Cnv1.xls**

5 source: … \Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**L813_Cnv0.xls**

6 source: ….\Plan 6\Studies\L813**Analysis of Optimization Run_L813vL811.xls**

Source: workbook "L813_conservation_sensitivity 100301.xls," worksheet "Table"

Some of the entries in Table J-2 require explanation. Each row describes the results of a particular study. The first column indicates whether there is a carbon penalty present. The model uses average carbon penalty across future in the deterministic models. If the model is stochastic, it uses the full 750 futures of carbon penalty. The second and third columns have the market adders for lost opportunity (LO) or discretionary (NLO) conservation. The values to the right of these columns identify the average megawatts (energy) developed and the cost of conservation. Both of these values are for conservation at the end of the study. The costs are averages across futures for all conservation acquired up to the end of the study.

At the far right is a column that contains numbers which refer to the references at the bottom of the table. These references indicate where to find the corresponding model results.

ENHANCEMENTS TO THE MODEL

The following are changes to the model logic since the Fifth Power Plan. The Fifth Power Plan, especially Appendices L and P, describes the model as it stood at that time. Many of the underlying concepts remain the same. The discussion here emphasizes the changes that could affect the results of the model.

Capacity and Costs Related to Capacity

In the early stages of developing the Sixth Power Plan, stakeholders and the Council identified construction cost uncertainty as a concern. Treating the uncertainty in construction costs, however, raises other questions. Should uncertainty in construction costs be tied to the seasonal or long-term capability of a unit or to the original nameplate capacity? How do other costs vary? Is fixed operation and maintenance cost similarly affected? Should capacity or capability be variable? Should the model give the user the ability to vary these factors deterministically, as well?

Ultimately, all of these features found their way into the revised model. Making the changes at the same time afforded economies of time and effort. Moreover, because of the nature of these changes, there is less chance of errors if other features are added at the same time. The basic changes are complicated enough that the overall architecture of the logic must be mastered again. Other modifications that could be made with little or no additional development effort therefore were completed. For example, a relatively simple enhancement was the addition of uncertainty in commercial availability of a new technology.

The following is a summary of and introduction to the sections that follow. These are changes only to capability and fixed cost features of the model:

- In the Fifth Power Plan, construction costs did not have the kind of detail that staff needed. Specifically, mothball and cancellation costs depend, in a sensitive fashion, on when the decision is made to defer or cancel construction. Enhancements for the Sixth Power Plan model now reflect those preferences.

- Internalized decision making, including decisions based on forward-going fixed costs, became not only preferable but in fact necessary.

- Provisions now exist for adjusting all fixed costs, including fixed operations and maintenance (FOM) and construction cost, both deterministically and stochastically.

- Enhancements also provided for adjustable capacity due to seasonal effects and adjustment over the study, both for cost and for energy calculation purposes.

- Finally, staff anticipated that retirement logic would be useful for evaluating the implications to coal-fired power plants of carbon penalties. It would also provide more realistic modeling of less efficient gas-fired units in the region.

In total, there about 16,388 combinations of new features and their interaction can be subtle. These are enumerated at the end of the section.

As a basis for describing the enhancements, understanding of some features as they existed in the Fifth Power Plan is helpful. The next section introduces that background.

Fixed Cost and Capability Treatment in the Fifth Power Plan

In the model, construction may begin in any period, subject to user choice. That is, the model permits additions to be made in every period, but the user must specify the maximum amount of each type of resource that can be added in that period.

When the model runs under the ***optimizer***, the optimizer tries different amounts of capacity within the permitted range for each type of resource. Whenever a study tries to identify the efficient frontier and the least-risk plan, it is an optimizer that is doing the work. It is the optimizer that creates and tests the plans under identical sets of futures.

Cohorts are identical units that may begin construction at the same time. Units are identical in the sense that they have the same technology and fuel, and they face exactly the same costs and market prices. They have the same unit size. Cohorts exist because the model adds new capacity in multiples of some fixed unit size.

In a given period, for example, a plan may specify that only one unit can begin construction, only two units may begin construction, or some other pre-specified number may begin construction. Of course, because all cohorts face the same circumstances, all cohorts see the same decision criterion value and will respond identically.

One feature that has not been used in either the Fifth Power Plan or the Sixth Power Plan is discretionary addition of resources by the model under favorable market conditions. The reason for excluding this option is probably obvious: the Council is tasked with producing a resource portfolio, including the timing and selection of resources. The subject feature leaves that decision to the market place. The selection of this feature, therefore, would be in a sense an abdication of the Council's role.

Nevertheless, if the user selects this feature, he or she must specify the maximum number of units that may be added in a particular period. Without that limitation, nothing would restrain the model from adding an arbitrary number of units whenever the market indicated that a single unit could make money.

The model partitions construction activities into three phases. There is an initial ***planning phase*** which is often quite long but typically costs only 1 or 2 percent of the overall project budget. In Council studies, the optimizer assumes that this phase has been completed. The model associates with a plan the cost of the planning for each resource in that portfolio. The decision criterion for construction is not used during this phase.

The second phase is an ***early construction phase***, during which the decision criterion determines whether to continue with construction or to defer or cancel the unit. The third phase is a ***late construction phase***, during which construction continues without regard to circumstances. The plant is completed and brought online. It is assumed that most of the money has been spent before this third phase begins. The best economic outcome at that point is to complete the plant and let it produce whatever value it can.

In the Fifth Power Plan, the rate of expenditures was the same for the early and the late phase of construction. Construction costs rates are more flexible in the new model, as this appendix will explain.

Another feature of the original construction logic was a provision to have all of the funds spent in the first period of each construction phase. It has been observed that very often, expenses are not even during a phase, but instead much of the expense is up front. These up-front expenses are for key components, often the initial or final payments on boilers or combustion turbines. These junctures also mark the beginning of a new phase of construction. By providing the capability to represent this in the model's logic, the relation of expense to decision making is more credible.

These existing capabilities must be integrated with the new features, however. We will return to this task in the context of each feature.

More Detailed Specification of Construction Costs

In the model, deferral (mothballing) and cancellation can occur only during the early construction phase. For the Fifth Power Plan, whether the decision was made early or later in this early phase had no impact on the cost. For the Sixth Power Plan, the logic allows that if the decision is made early, the cost is less.

There are at least two types of mothball costs – a fixed, one-time charge, and a charge for each period construction is deferred. In the Fifth Power Plan, the model used only the latter. This is one area where no significant improvement has been made. Unfortunately, recognition of the fixed component of mothball costs came only at the end of the development process. Also unfortunate is the fact that the fixed costs appear to dominate the variable costs. They can be as much as 32 times larger than the variable costs. Repairing this deficiency has therefore moved to the top of the task list for the next version of this logic.

Several unanswered questions about mothball fixed costs remain. For example, is it applied again if construction restarts and then stops again? Study of these costs is warranted before making any more advances in this area.

Mothball and cancellation costs are capitalized and amortized, rather than expensed. To expense them would introduce distortions in economic value calculations. The assumption holds that costs prior to the end of the study are representative of life-cycle costs. Mixing conventions would distort this representation.

Note that there is no treatment of deferral and cancellation during the planning and late construction phases. The planning and late construction activities are insensitive to decision criteria, by assumption.

Finally, deferral and cancellation costs can arise during retirement of power plants. Modeling these has its own set of issues. The section **Economic Retirement** below discusses the issues.

Any adjustments or escalation in the real cost of construction, deferral, or cancellation will be applied to construction and retirement costs in the same way. The Council’s Generation Resource Advisory Committee (GRAC) recommended this policy, and there is no compelling reason to do otherwise.

Uncertainty in Construction Costs and in Fixed and Variable O&M Cost

The Sixth Power Plan model implements uncertainty in construction costs and in fixed and variable operation and maintenance (O&M). The model uses multipliers that differ from period to period. Each future has a distinct sequence of multipliers with strong correlation from one period to the next. The Fifth Power Plan model had no such treatment.

The treatment of uncertainty for expenses differs fundamentally from that of capitalized cost. The construction cost incurred in a given period is affected by the multiplier in force only in that period. The levelized value of that period's cost then carries forward to each remaining period of the economic life of the unit. This is not true, however, for fixed and variable operations and maintenance (O&M). Fixed and variable O&M multipliers affect only their period costs. Levelized costs do not carry forward to subsequent periods.

Economic Retirement

The current model takes a more realistic approach to the treatment of economic retirement than did the Fifth Power Plan model. In the Fifth Power Plan, the model reflected a prescriptive loss of about 1,000 megawatts of inefficient gas-fired generation in the region. Understanding the effect of a carbon penalty to power plant economics is also a motivation to better modeling in this area.

Economic retirement is signaled by decision criteria based on forward-going fixed O&M cost. If the decision criterion is negative for a prescribed number of periods, the model effectively decommissions the unit.

In principle, this feature could be available for both existing, non-surrogate plants and for new candidates. ***Surrogate plants*** are as those that represent a class of similar dispatchable units. The units are similar in the sense that they have identical fuel type, heat rate, variable O&M costs, technology, and fuel cost. They dispatch, therefore, at the same electricity price and produce the same value per period.

A decision criterion for new candidates, however, requires separate tracking of fixed O&M for every cohort. Each cohort will have a distinct fixed cost requirement due to prior commitments. Each cohort will therefore have its own threshold for economic feasibility. This means new logic is necessary to track these elements. For example, when a new plant comes online, an offset of units and fixed O&M are added to a period at the end of the plant life. If the unit is retired early, however, these values need to be removed and replaced by the revised values.

These complications and the press of the Sixth Power Plan schedule forced the decision to pick up such improvements later. Power plant retirement is only available for simple existing units.

Other expectations, however, support this limited scope. Any specific existing resources that are candidates for retirement probably merit their own representation. Any new resource candidates should be more efficient than existing units. Their retirement, therefore, would be unlikely.

Uncertainty about Commercial Availability

New technologies usually have uncertainty about ***commercial*** availability. Even if a generation technology is feasible, there often is uncertainty about its eventual cost and ease of implementation. In discussions with various advisors, the following representation emerges.

At the beginning of each future, the value of a random variable is selected. This variable has as its value the year when commercial availability is achieved. It may be that this value is beyond the study horizon. In that case, the technology effectively is never commercially available.

As with other new candidates, cohorts can be constructed in any period the user specifies. The pre-study logic, however, assigns a special status code to all periods before the commercial availability variable's period. This status code indicates that the cohort is not commercially available. This has the effect of causing the schedule to simply slip until the technology becomes available and the first period of planning or construction phase can begin.

Note that all cohorts are treated equally in this case. All cohorts will become available in the same period.

One question associated with this representation is whether there are costs incurred during periods in which the technology is not commercially available. Another question is whether a technology should lose its siting and licensing if it doesn't become commercially available within specified amount of time. For this first version, the technology does automatically lose its license and terminates. The maximum delay is equivalent to the time limit for mothball status.

Finally, how do the deferral and cancellation cost due to commercial infeasibility compare with those due to construction? In the current version of this feature, the deferral cost is the same as for the "first period" construction mothball decision. For further discussion, see the section, ***More Detailed Specification of Deferral and Cancellation Costs***.

Integrated Forced Outage Rate

One of the deficiencies in the Fifth Power Plan model was forced outage behavior for new resource candidates. In actuality, new units bring a diversification effect. We had not accounted for this in the Fifth Power Plan model. Only a block deration for forced outages of new candidates existed.

The objective of this new logic therefore is to provide cohort-specific forced outages. This produces the diversification effect and improved reliability of the ensemble. Of course, the deration option is still available.

One of the benefits of handling forced outage rates internally is reduced reliance on Crystal Ball® random variables. The Crystal Ball random variable calculation is slow. Most of the 1,100 random variables the Fifth Power Plan's model employs are for modeling forced outage rates associated with large, existing thermal units. The new planning flexibility function permits not only better treatment for forced outages of new and existing power plants, it reduces the number of Crystal Ball random variables to 384.

Consequences for the Algorithms

The Sixth Power Plan's model calculates outages for all cohorts of all plants at the beginning of each future. An alternative is to calculate and store forced outage events beforehand. The model then would use a Crystal Ball random variable to select the outage values for each future, plant, period, and cohort. This has the disadvantage, however, of requiring significant storage. If storage needs become large, that can increase execution time as well. Consequently, the model adopts the first approach that did the job.

Forced outages use the following model. Overall power systems fail when a series of components fail. Each component is assumed to have failure rate with an exponential distribution, a standard assumption. For multiple component failures, the system will have a gamma distribution, which is determined by the Mean Time to Failure (MTTF). Similarly, we assume that the simple systems must be repaired before the restoration of the overall system is complete. Restoration will similarly have a gamma distribution determined by a Mean Time Before Repair (MTBR). Again, the components have exponential distribution. We assume one-half dozen simpler systems fail and require repair.

The random variable for the forced outrage rate (FOR) is the ratio MTBR/(MTTF + MTBR), which will have a beta distribution. Knowing the FOR and MTBR is adequate to computing all the other information necessary to specify the distribution.

Variable Capacity

Variable capability of power plants over time is another new feature. Capability might vary by future as well as period, and it might change stochastically or deterministically. Important applications of this feature include representing maintenance and seasonal efficiency.

There is a problem, however, with doing this for surrogates and for new candidates. These are collections of plants. The model currently cannot tell which cohort or plant within a collection to modify.

Consequently, any kind of unit can have variable capacity, but with limitations. For surrogate units and new candidates, the same adjustment applies to all units or cohorts in each collection. That is, the adjustment is simply applied to all output of the collection.

One concern is how or whether this adjustment should affect decision criteria for new plants and for economic retirements. The economic feasibility of a plant is determined on a per-megawatt basis. If the variation is seasonal, however, the expected capability is affected. The adequacy calculation for the decision criterion is also affected. The annual average must be calculated for the decision criteria in these situations. Otherwise, variations in capability are unforeseeable and would therefore not affect the decision criteria.

Adjustments to capacity do not affect costs associated with construction. In principle, they could. A future version of the model will permit the user to specify whether or not this is the case.

For this adjustment, a new capability permits cyclical reading of input data. For example, assume a sequence of adjustments for the first four hydro quarters. The model will return to the first period’s adjustment for a value to use for the fifth period, and so forth. This happens automatically if the data are not provided for every period.

New Utilities

New utilities provide greater transparency of the model’s internal calculations. This improves understanding and the reliability of the model and data. For example, it is now easy to report:

- Forced outage rate, by cohort, plant, and period.
- Capability for adequacy estimation.
- Internal decision criteria estimation, by cohort, plant, and period. Supporting values are also available.

- Fixed O&M adjustment by cohort, plant, and period.
- Capital costs by cohort, plant, and period
- Information about the construction status of new units

Special auditing software now provides the ability to look not only at the value of ranges within the model's worksheet, but also the content of selected Microsoft® Visual Basic® arrays. These arrays are used to store detailed information about the state value of each existing and new resource. These can be extracted in a number of formats, including those suitable for spinner graphs, pivot tables, and database records.

Input Variables and Feature Selection

The user selects options from a compact matrix next to each resource. Below, in Figure J-4, the new capabilities are in the first row. The second row of variables is identical to those in the Fifth Plan model, with one exception. The exception is highlighted in yellow and uses red font. There is a slight change in the interpretation of that value, as explained by a comment in that cell.

Figure J-4: Fixed Cost and Capability Specification

															610 MW CC 030708			
Option Selection (integer)	FOM (R $M/ MW/ period)	Late Constr Costs (RL $M/ MW/ Period^2)	Earliest Availability (Period)	Regional Share	Retirement mothball life (periods)	Retirement evaluation cost (RL $M/MWPeriod)	Decommisioning cost (RL $M/MWPeriod)	First Period Mothball Costs(RL $M/ MW/ Period)	First Period Cancellation Costs (RL $M/ MW/ Period^2)	Generation technology	Status	LT Fuel Price (Range name)	MTBR (weeks)	FOR [0…1]	Nameplate (MW) - required for cost calcs of existing units only			
44144	0.013101	0.003000		100%				0.000029170	0	CCCT	New			0.05	378.3			
Criterion Set ID	Planning Periods	Early Construction Periods	Late Construction Periods	Development Costs (RL $M/ MW/ Period^2)	Mothball Costs (RL $M/ MW/ Period)	Cancellation Costs (RL $M/ MW/ Period^2)	Early Constr Costs(RL $M/ MW/ Period^2)	CancelThreshold (	Const Cost Escl (.01=1%/period)	ResourceLife (periods)	OptionLife (periods)	Market-driven ramp rate (MW)	Planned Development Costs (RL $M/ MW/ Period^2)	**Index**				
CCCT Criterion_004	0	4	6	0	0.00068613	0.0014288	0.003137106	-99999	0.000%	120	20	FALSE	0.00132581	0				
															Construction Cost Variation	1	1	1
															Manifest Capability (MWa)	0.0	0.0	0.0
															Cost ($M Real)	0.0	0.0	0.0
	Study ID	Availability	DHF(0=Dis	Fixed Ener	Fixed Cost ($/l	Fuel Set (ID	Heatrate (MMB	Planning Flexibility ID	Capacity ID (I	Cap_Decisior	Variable Cost	Hydro Structure ID		12	Energy(MWh)	0.0	0.0	0.0
	1	(none)	0	(none)	(none)	PNW East N	7.1	CCCT-01 Annual_004	CCCT Capaci	0,6000,1500,(	1.82	(none)			Cost ($M)	0.0	0.0	0.0

The user specifies which combination of features the model will use with an integer in the first column of the new row. In a separate location within the RPM, the user can specify with simple yes or no flags whether to use the particular option. The worksheet returns the integer corresponding to the choices. The coding logic appears in Figure J-5.[9] The user may also need to decode a particular option selection from the integer. Figure J-6 illustrates the formula in the workbook that performs that function.

9 At first glance, this figure suggests that a much larger number, 65536, are available. In fact, one option is not currently in use. Also, the selection of the 2004 logic excludes the use of other options, except for market additions and early use of all early construction funds in the first period of early construction.

Figure J-5: Encoding the Selection of Options

	Option selection		Plant status (for data validation)
1	no	Use 2004 logic	Existing
2	no	FOM Variable (& differs each gam	Existing Aggr
4	no	VOM Variable (& differs each gam	New
8	no	Capability Variable?	
16	yes	Construction Cost Variable (& differs each game)?	
32	yes	Use Distinct Cost for Committed Construction?	
64	yes	Use Internal Decision Criterion?	
128	no	Economic Retirement Logic?	
256	no	Stochastic FOR?	
512	no	Stochastic Availability?	
1024	yes	Use Distinct Cost for Mothballing in First Period?	
2048	yes	Use Distinct Cost for Cancelling in First Period?	
4096	no	Capability Differs Each Game?	<== not currently in use
8192	no	Spend early construction phase cash in first period	
16384	no	Permit Market Additions	
32768	yes	Read construction costs from the internal array	
	35952		

Figure J-7 has detail from the first row in Figure J-3. This particular example is for an existing surrogate natural-gas fired power plant. After the first column, most of the remaining input data values have ranges, units, and types that are apparent from the context. Some are not, however, and explanation is necessary.

Figure J-6: Decoding a Selection of Options

		44144	
		INVERSE	
0	1	FALSE	
1	2	FALSE	
2	4	FALSE	
3	8	FALSE	
4	16	TRUE	Construction Cost Variable (& differs each game)?
5	32	TRUE	Use Distinct Cost for Committed Construction?
6	64	TRUE	Use Internal Decision Criterion?
7	128	FALSE	
8	256	FALSE	
9	512	FALSE	
10	1024	TRUE	Use Distinct Cost for Mothballing in First Period?
11	2048	TRUE	Use Distinct Cost for Cancelling in First Period?
12	4096	FALSE	
13	8192	TRUE	Spend early construction phase cash in first period
14	16384	FALSE	
15	32768	TRUE	Read construction costs from the internal array

FOM (R $M/ MW/ period) – fixed operation and maintenance cost – This is fixed operation and maintenance expense expressed in millions of constant (or "real") dollars per megawatt per period. The final fixed O&M rate is subject to any escalation and variation multiplier.

Late Constr Costs (RL $M/ MW/ Period^2) – If the user specifies a distinct cost for construction during the late construction phase, the rate is specified here in real levelized millions of dollars per megawatt per period for each period. This is a rate of cost accumulation during construction. By the end of construction, the total accumulated real levelized cost is carried forward to subsequent periods.

Earliest Availability (Period) – This is a stochastic variable used by the model when the user specifies uncertain commercial availability. The value of the stochastic variable indicates the earliest of that construction can begin.

Regional Share – Some units have a portion of their output dedicated to independent power producers (IPPs). They are not owned by a regional utility. They are not under firm contracts for regional use. If this is the case, only part of the output accrues to the region. The remaining energy will be supply to the wholesale power markets. Otherwise, it does not benefit the region.

Retirement mothball life (periods) – This is the number of periods that a unit can be uneconomic before permanent decommissioning. During this time, retirement is continuously evaluated.

Retirement evaluation cost (RL $M/MWPeriod) – During retirement evaluation, costs may accumulate. The user specifies the cost here. Costs are in real levelized millions of dollars per megawatt per period. This cost appears in each period before decommissioning. This cost disappears after decommissioning.

Decommissioning cost (RL $M/MWPeriod) – After the decision to decommission a unit is final, there are additional costs. The user specifies that cost here. Costs are in real levelized millions of dollars per megawatt per period. This cost carries forward over the unit's remaining economic life.

First Period Mothball Costs (RL $M/ MW/ Period) – As described above, an early decision to mothball construction can save money. If the user chooses this treatment, he specifies so through the integer in the first column. He then enters in this column the cost, in real levelized millions of dollars per megawatt per period. This cost carries forward until construction resumes.

First Period Cancellation Costs (RL $M/ MW/ Period) – This feature, described earlier, works in the same manner as **First Period Mothball Costs**, with one exception. This cost carries forward for economic life of the unit.

Generation technology – If a resource is a candidate for capacity expansion or economic retirement, the type of technology (SCCT, CCCT, Wind, etc.) is required in this column. Microsoft® Excel® data validation restricts the choice to a prescribed list. The decision criterion needs this information to know which factors to consider.

Status – A unit's status can be "existing" or "new". If it is "existing", it is a "surrogate" unit or a "simple" unit. The construction and the decision criterion logic use this value to make appropriate choices.

LT Fuel Price (Range name) – This is the worksheet range name of the long-term fuel price forecast. The decision criterion uses the forecast to determine economic viability.

MTBR (weeks) – The user can choose stochastic forced outages as an alternative to capability deration through the integer in the first column. The model then needs both the forced outage rate (FOR) and the **Mean Time Before Repair** for this unit. This is expressed in weeks. See the discussion above for more information about modeling forced outages.

FOR [0…1] – The forced outage rate is required for all units. If the user does not specify that the unit uses stochastic forced outages, the model will derate a unit's capability deterministically by the forced outage rate. The value in this field should lie between zero and 1.0. For example, if the forced outage rate is 5 percent, the value in this field is 0.05.

Nameplate (MW) – Existing units use this nameplate capacity. It is subject to FOR and capacity adjustments. New generation does not require this information. New generation takes its capability directly from the decision cells at the top of the worksheet. Typically, an optimizer controls these.

The model also uses this value, before adjustments, to calculate fixed O&M costs before any fixed O&M adjustment. If there are no fixed O&M costs, it may be convenient to set this value to 1.0 and express capacity directly through capacity adjustments.

Figure J-7: Detail of options in previous figure

															West 1
Option Selection (integer)	FOM (R $M/ MW/ period)	Late Constr Costs (RL $M/ MW/ Period^2)	Earliest Availability (Period)	Regional Share	Retirement mothball life (periods)	Retirement evaluation cost (RL $M/MWPeriod)	Decommisioning cost (RL $M/MWPeriod)	First Period Mothball Costs(RL $M/ MW/ Period)	First Period Cancellation Costs (RL $M/ MW/ Period^2)	Generation technology	Status	LT Fuel Price (Range name)	MTBR (weeks)	FOR [0...1]	Nameplate (MW) - required for cost calcs of existing units only
264										CCCT	Existing Aggr		0.143	0.05	1.00

The following illustration (Figure J-8) shows how options interact.

The final Sixth Power Plan did not use some of the new features.   In particular, the GRAC suggested that a coal plant would never be retired for economic reasons. Consequently, staff decided to retain existing coal plants in the region's portfolio of resources unless a study explicitly called for their removal.

Studies relied primarily on the model's new features for representing variable costs and stochastic forced outages. Variable construction and FOM costs found extensive use. Most of the variable costs were stochastic, and they contributed to modeling future uncertainty.

Figure J-8: Impact of Modeling Choices on Various Costs

end of study dollars	FOM Adjustment on original capacity	FOM Adjustment on modified capacity	VOM Adjustment	Capacity Adjustment	Construction Cost Adjustment on original capacity	Construction Cost Adjustment on modified capacity	Commercial Availability	Stochastic FOR	Escalation rates		Use 2004 logic	FOM variable over study	FOM variable over study and over future	VOM variable over study	VOM variable over study and over futures	Capability variable over study	Capability variable over study and over futures	Construction Cost variable over study	Construction Cost variable over study and over fugure:	Use Distinct Cost for Committed Construction	Use Internal Decision Criterion?	Stochastic Availability?	Use Distinct Cost for Mothballing in First Period?	Use Distinct Cost for Cancelling in First Period?	Initial capability Differs Each Game?	Spend early construction phase cash in first period	Permit Market Additions	Read construction costs from the internal array	After on-line	Economic Retirement Logic?	Stochastic FOR?
sunken development cost ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X										X				
development cost ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X								X	X			
mothball cost, first period variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
cancellation cost, first period variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other mothball cost variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other cancellation cost variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
mothball cost, first period fiXed ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
cancellation cost, first period fiXed ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other mothball cost fiXed ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X		X				
other cancellation cost fiXed ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X		X				
early construction costs ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X	X	X	X			
late construction costs ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X	X	X							X			
FOM cost ($)	X	X		X												X	X						X	X	X	X		X		X	X
VOM cost ($)			X	X				3				X	X	X	X	X	X						X	X	X	X		X		X	X
fuel cost ($)				X				3								X	X						X	X	X	X		X		X	X

1 Because FOM only affects operations, and in particular, only affects costs after construction, this does not affect any construction costs.

2 Because these affect only operations, they do not affect any construction costs.

3 Stochast FOR affects variable cost, not fixed cost

Source: workbook "Relationship among variables.xls", worksheet "Sheet1"

RPS Modeling

Chapter 9 of the Sixth Power Plan summarizes the renewable portfolio standards (RPS) adopted by the Pacific Northwest states. The states of Washington, Oregon, and Montana have RPS requirements. Typically, an RPS specifies that obligated utilities will meet a certain portion of their future energy needs with renewables. The RPS gives a schedule that extends over several decades for meeting these targets.

There are several challenges in modeling RPS requirements. Each state has different requirements and policies. The obligation of utilities depends on their size, as measured by customers or load. Also, utilities typically may “opt out” of their targets. For example, some utilities can decline if meeting the standards would cause utility revenue requirements to exceed their requirements otherwise by 4 percent.

Representing RPS standards with the regional portfolio model (RPM) introduces several more problems. The RPM uses 750 distinct regional load forecasts. These regional load forecasts must somehow be allocated down to the utility level. Moreover, the RPM can option wind and geothermal resources to reduce cost and risk to the region. If these resources are present in a study, the model must coordinate the RPS acquisition of these resources. The model must have rules for allocating any such new wind or geothermal energy back to individual states, if not utilities. This energy presumably would apply toward their RPS targets.

There is a concern that the model might treat the RPS and non-RPS resources differently because of how construction risks are represented. Wind, geothermal, and other new technologies have detailed construction logic. This makes possible the accounting for the costs of delays, cancellation, and changing circumstances. The RPS resources, however, do not have this detail. A more aggregate approach is necessary. Also, because Council studies assume that states will always meet their RPS targets – or some fixed portion thereof – the question of construction uncertainty is moot. RPS resources therefore do not carry the cost associated with construction risks.

Another challenge in modeling RPS standards with the RPM is dealing with limits on the potential development of renewables. The Council has estimated the amount of cost-effective renewable potential in the region. This estimate exists for each type of renewable. The RPM needs rules to decide when renewables are used to meet RPS requirements. It must know whether their renewable energy credits (RECs) can and should be sold. It needs to know whether the required RPS development would exceed the regional potential and what should be done in that situation. This means anticipating where the renewables would come from and what they would cost. Ideally, the cost of RPS renewables would match the cost of non-RPS renewables having identical technology, location, and circumstance. In particular, RPS renewable construction would have the same cost uncertainty treatment.

Representation

Early RPM studies allowed for RPS and non-RPS renewables serving energy needs simultaneously. That is, the model could option wind and geothermal resources and then meet any remaining RPS requirement with forced-in renewable energy. This made it possible to see whether renewables might be selected earlier or in greater quantity than the RPS targets.

It became evident, however, that the model never developed renewables more aggressively than the RPS rules required. In studies that assumed no RPS obligation, the renewables still enter the efficient frontier. Their schedules, however, do not keep up with their duty under an RPS.

Consequently, none of the final Plan scenarios have both RPS and non-RPS renewables in the same study. Either the RPS model is active and discretionary wind and geothermal are excluded, or the opposite is the case.

This policy has the benefit of solving some of the problems described above. Coordination is not necessary. There is no inconsistency due to construction risk – at least within a study – so one approach is not disadvantaged relative to the other. Allocation of non-RPS resources to individual states is not necessary. Not insignificant, the results of studies are easier to communicate.

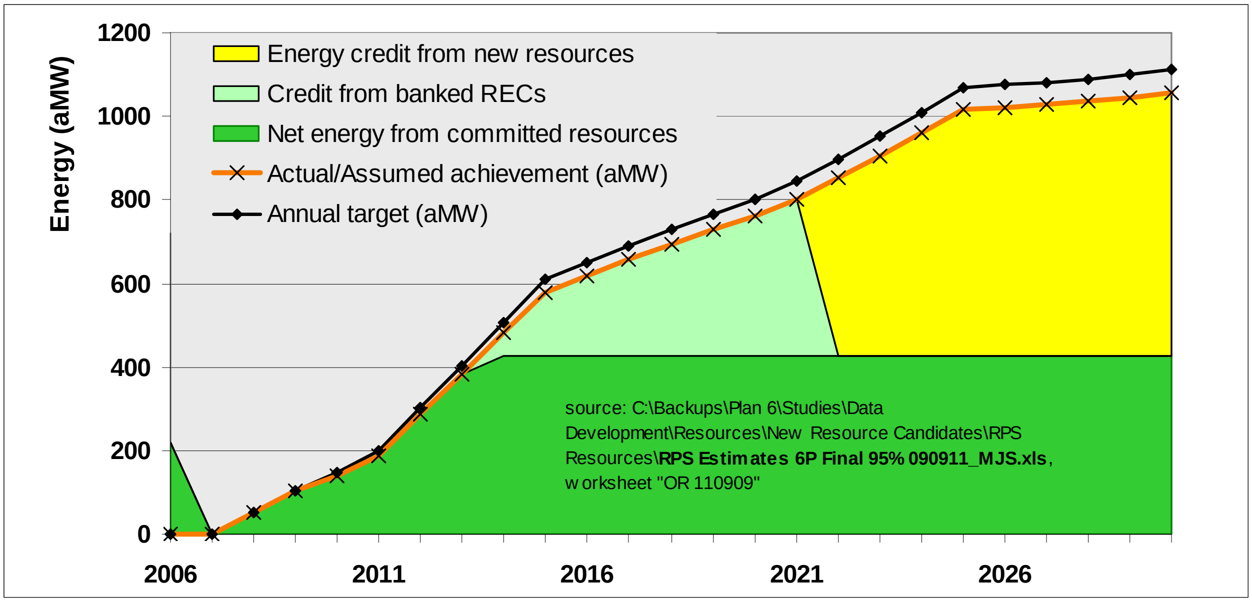
The logic in the RPM is based on an analysis that staff performed in the fall of 2008[10] and updated in fall of 2009[11]. The analysis estimates the amount of renewables already developed by each of the states. It identifies the obligated utilities and their respective RPS targets. The targets are reduced by 10 percent to reflect expectations that certain utilities will "opt out." The estimate of 10 percent is based on study of specific utility rates of load growth and their resource alternatives

10 See "RPS Estimates 100708.xls" and subsequently "RPS Estimates 021909.xls"

11 See "…\Plan 6\Studies\Data Development\Resources\New Resource Candidates\RPS Resources\Final Plan model\RPS Estimates 6P Final 95% 110909.xls"

for meeting demand. Finally, it estimates the number of REC credits that each state has acquired to date. The final forecast REC balance is shown in Figures J-9 through J-11, below.

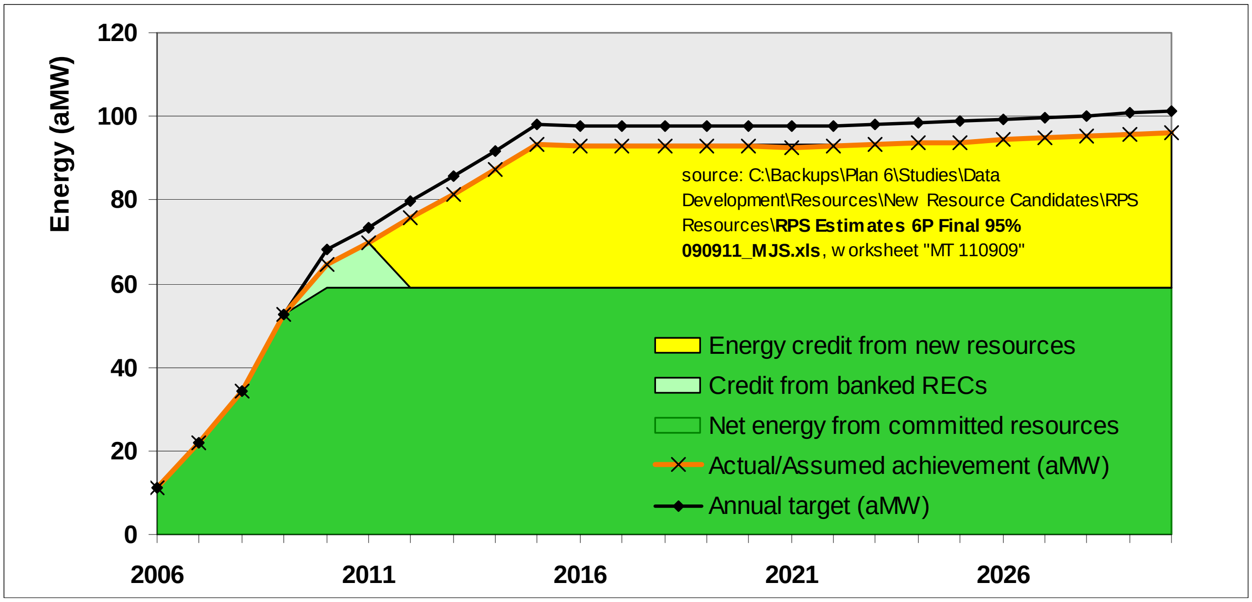
Figure J-9: Forecast REC Balance for the State of Oregon



Some utilities are able to bank the REC credits they acquire by building renewables in advance of need. The three states have different rules on how long a utility can bank its REC credits, however. In Oregon, REC credits never expire. In Washington, they expire after one year. Montana permits utilities to bank their credits for two years.

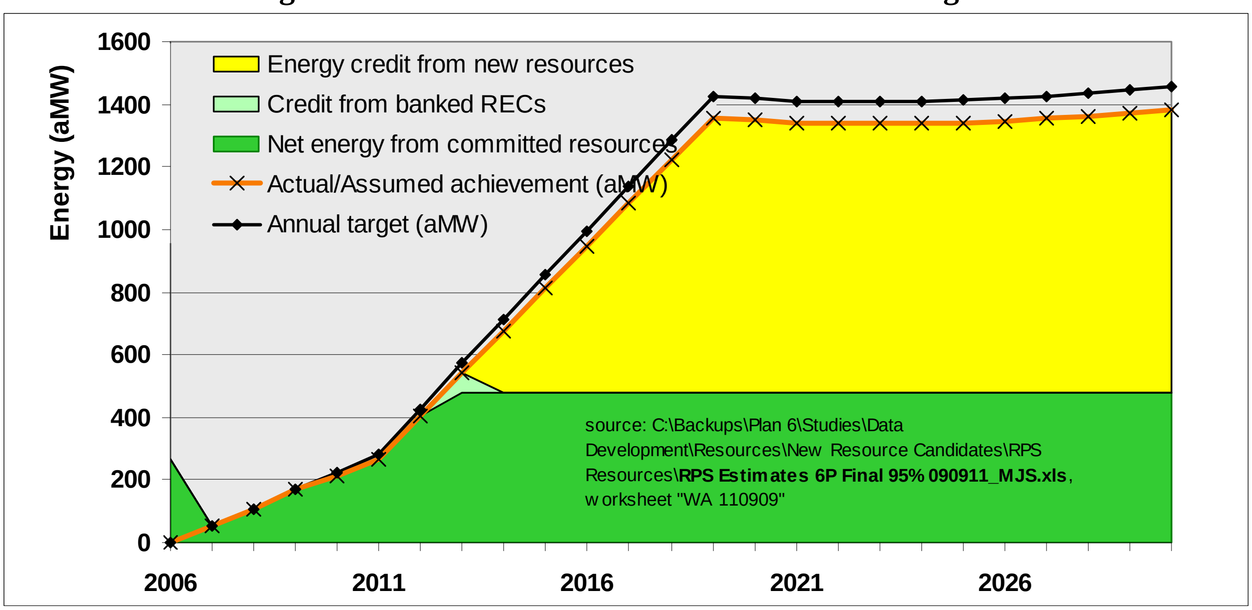
The RPM must track load, conservation, RPS requirement, and REC credit created, banked, expired, and used for each of the states. It must track the cost for any renewables acquired to meet state targets after credits are exhausted. The cost for new renewables sees the same adjustment for uncertainty, escalation, and so forth that costs of individual renewables in the model see. The levelized cost is carried forward the same way that it is for non-RPS resources. (The treatment for non-RPS resource costs is described in the section above, "More Detailed Specification of Construction Costs.")

Figure J-10: Forecast REC Balance for the State of Montana



To estimate the gross RPS requirement for each state, the model uses a fixed estimate of the percentage of the region's load that each state's obligated utility load represents. This is about 3.3 percent for Montana, 27.2 percent for Oregon and 39.7 percent for Washington. The fraction of each state's obligated utility load that renewables must meet increases over time. Rules typically state the fraction for only three or four years, for example, 2015, 2020, and 2025. Straight line interpolation provides the model with estimates for the intervening years. For the first year in the RPM, hydro year ending August 2010, this interpolation yields 10 percent for Montana's obligated to load, 3 percent for Oregon's, and 2 percent for Washington's.

Figure J-11: REC Balance for the State of Washington



Given a future and plan, the model performs calculations period by period. For each period, results depend on achievements in prior periods and circumstances in the current period.

The period estimate begins with the gross RPS target for each state. This depends primarily on the level of electricity needs over the prior year (four hydro quarters) and conservation acquired. This is apportioned to each state as described above. The gross value is constrained to be non-decreasing. It is unlikely that a utility would ask for a smaller target due to, for example, short-term load variation. See Figure J-12 for the example of Montana's calculation.

The model then nets each state's gross RPS target, energy from existing renewables, and balance of banked RECs. According to the most recent study, Montana has about a 65 average megawatts of existing renewables; Oregon has about 465 average megawatts; and Washington has 520 average megawatts. The estimate of credits for each state is based on the Council's inventory of existing renewable projects.[12] In early years, state RPS requirements are minimal. Utilities with renewables therefore accumulate RECs subject to their state's banking rules. Figure J-13 displays the formulas.

Figure J-12: Allocation of RPS Obligations

	O	P	Q	R	S	V	V
697							
698				Sep - Nov 2009		Sep - Nov 2010	
699			**RPS resources**				
700			Load, less conservation (MWa busbar)	21200		21138	m=-(V$331+V$333)
701		MT obl ut requirement sales (MWa)	3.1%				
702			MT obl ut target (%)	**0%**		**10%**	10%
703		OR obl ut requirement sales (MWa)	26.9%				
704			OR obl ut target (%)	**0%**		**3%**	3%
705		WA obl ut requirement sales (MWa)	40.3%				
706			WA obl ut target (%)	**0%**		**2%**	2%
707		Assumed Achievement	95.0%				
708							
709			MT obl ut target (MWa busbar)	57.4		61.4	m=MAX(V$700*$Q$707*$Q$701*V702,R709)
710			MT resources (MWa busbar)	65.0		65.0	m=R710
711			MT credits remaining (MWa equivalent busbar)	6.0		13.6	m=R710+R711-R709
712			MT net requirement (MWa)			-17.2	m=V709-V710-V711
713			Sell RECs*				
714			Carry forward credit*			17.2	m=MAX(0,-V712)
715			Buy Renewables			**0.0**	m=MAX(0,V712)
716							
717		source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations**Resources\L813 for illustrating RPS.xls**					

The net requirement may be either positive or negative. That is, the state may either need to acquire new RPS energy or not.

If the requirement is negative, the utilities could either sell the associated RECs or carry the credit forward. If the utility did not need the credits or the credits would expire before the utility could use the RECs, it would make more sense to sell the RECs. Oregon's credits never expire so there is little sense in Oregon utilities selling them. For Washington and Montana, the decision is not as clear.

Whether or not older RECs are sold or expire, however, has little significance for the question of acquiring new regional resources. First, any revenue from selling the RECs would only accrue before about 2011 for Washington and 2008 for Montana. RECs acquired after these date would have value meeting RPS requirements and presumably be retained. The amount of revenue from two years of REC sales in Washington would be relatively small. Second, the revenues are practically "sunk." The effect of expected conservation, a factor that can affect REC requirements, has already been included in the forecasts for RPS requirement in Figures J-9 through J-11. Variation in forecast conservation energy is insignificant over the first two years of the simulation. Consequently, the revenues would be the same for all plans in each future.

12 …\Plan 6\Studies\Data Development\Resources\Existing Non-Hydro\091018 Database system\091018 Original Sources\Existing Projects 101809.xls

For accessing the impact on the region's need for new resource, therefore, the model can retain all RECs for utilities, rather than selling them. Old RECs in Montana and Washington may have been sold instead. Recently acquired RECs have not expired and would defer RPS energy. If retained, these RECs would have significant value in those states. Therefore, they likely would be retained.

If the net requirement is positive, on the other hand, the model adds the energy and cost of new RPS resources. In the example of Montana, the need for new RPS resource appears in row 718 of Figure J-13.

Finally, the energy and cost of new RPS resources across all three states is summed up in rows 738 to 744 of Figure J-13. The estimate of regional gross cost for the RPS resources is produced using an Excel formula for that purpose, dfuncRPSCost(). The formula assures that costs match those for wind generation exactly. The cost includes uncertainty effects for construction and for production tax credits. It also levelizes and transfers forward of the levelized cost. The worksheet calculates the gross value of the energy in row 744 of Figure J-13.

Figure J-13: Detailed RPS Requirements Calculation

	N	O	P	Q	R	S	V	W	X
710					Sep - Nov 2009		Sep - Nov 2010		
711									
712				MT obl ut target (MWa busbar)	57.4		61.4	m=MAX(V$700*$Q$707*$Q$701*V702,R709)	
713				MT resources (MWa busbar)	65.0		65.0	m=R710	
714				MT credits remaining (MWa equivalent busbar)	6.0		13.6	m=R710+R711-R709	
715				MT net requirement (MWa)			-17.2	m=V709-V710-V711	
716				Sell RECs*					
717				Carry forward credit*			17.2	m=MAX(0,-V712)	
718				Buy Renewables			**0.0**	m=MAX(0,V712)	
719									
720				OR obl ut target (MWa busbar)	113.6		143.6	m=MAX(V$700*$Q$707*$Q$703*V704,R717)	
721				OR resources (MWa busbar)	465.4		465.4	m=R718	
722				OR credits remaining (MWa)	1053.4		1405.3	m=R718+R719-R717	
723				OR net requirement (MWa)			-1727.1	m=V717-V718-V719	
724				Sell RECs*					
725				Carry forward credit*			1727.1	m=MAX(0,-V720)	
726				Buy Renewables			**0.0**	m=MAX(0,V720)	
727									
728				WA obl ut target (MWa busbar)	186.0		194.2	m=MAX(V$700*$Q$707*$Q$705*V706,R725)	
729				WA resources (MWa busbar)	520.3		520.3	m=R726	
730				WA credits remaining (MWa)	607.3		941.5	m=R726+R727-R725	
731				WA net requirement (MWa)			-1267.6	m=V725-V726-V727	
732				Sell RECs*					
733				Carry forward credit*	941.5	m=R727+R726-R725	1267.6	m=MAX(0,-V728)	
734				Buy Renewables			**0.0**	m=MAX(0,V728)	
735									
736									
737									
738				**Regional net requirement (MWa busbar)**			**0.0**	**m=V715+V723+V731**	
739				**Gross Nominal Requirements (MWa** busbar after achievements)	357.0	**m=R725+R717+R709**	399.2	**m=V725+V717+V709**	
740				**Gross Nominal Requirements (MWh** busbar after achievements)	0	m=IF(ISBLANK(R$733),Q735,R734*2016)	804866.8	m=IF(ISBLANK(V733),U735,V734*2016)	
741				**Net regional energy on- and off-peak (MWh** busbar after achievements)	0.0	m=IF(ISBLANK(R$733),Q736,R733*2016)	0.0	m=IF(ISBLANK(V733),U736,V733*2016)	
742				**Net regional energy on-peak (MWh** busbar after achievements)	0.0	m=R736*1152/2016	0.0	m=V736*1152/2016	
743				Regional total gross cost ($M)	0.0	m=dfuncRPSCost(Q55,Q736,R736,R106)	0.0	m=dfuncRPSCost(U55,U736,V736,V106)	
744				Regional on- and off-peak gross value($M)	0.0	m=-R736*R$276/1000000	0.0	m=-V736*V$276/1000000	
745									
746			source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations**Resources\L813 for illustrating RPS.xls**						
747									

Perpetuity Factor and End Effects

This section describes an adjustment to costs to reflect the impact of irreversible circumstances, such as a carbon penalty, on the economic value of power plants. The model reports and uses NPV costs that have this "perpetuity" adjustment. The section describes the derivation and implementation of the adjustment.

The RPM uses real-levelized costs for power plant capital costs. Appendix L of the Fifth Power Plan explains the decision to use real-levelized costs. Briefly, levelizing spreads the construction cost of the plant evenly over its life. Spreading the cost matches the cost of construction with whatever value the plant produces.

It is typical to assume that plant cost and value within the time window of the study will represent those beyond the study horizon. For example, if a plant is profitable during the study, we have no basis for assuming it would not be after the study horizon. If a plant is more profitable than an alternative during the study period, we expect it would be after the horizon.

This approach saves the study from complicated and burdensome calculations. If costs were to resemble cash flow instead of being level, the timing of the cash flows becomes an issue. Cash spent for construction makes an investment look unattractive in early years. Studies would have to capture cost and value over the economic life of a plant to be representative. If a study had more than one resource, the study would have to capture these "life cycle" costs for resources with different economic lives. The lifetimes also are rarely matched, even if they are of equal length. Dealing with all these concerns requires a special "end effect" calculation. The end effect calculation, moreover, brings issues of its own. Levelizing eliminates all this.

If a carbon penalty appears during a study, however, the assumption underlying levelizing becomes questionable. Economics beyond the study horizon will more likely resemble that ***subsequent*** to the arrival of the penalty. Consider a carbon penalty imposed during the last two years of a study. A plant placed into service five years before the end of the study carries the penalty for 2/5 of its life ***in the study***. If the plant has a 20-year life, however, the penalty will in fact apply for the remaining 15 years of its life, or 18/20 of its lifetime.

As this section explains, the RPM model addresses this problem by extending all the costs in the study after the point in time when a carbon penalty appears. To allow for resources of unequal economic lifetimes, the model extends the costs in perpetuity. Portfolios can then be compared fairly on the basis of economic cost and risk. Users must take care, however, in the interpreting other measures, such as revenue requirements and rates, derived from NPV costs.

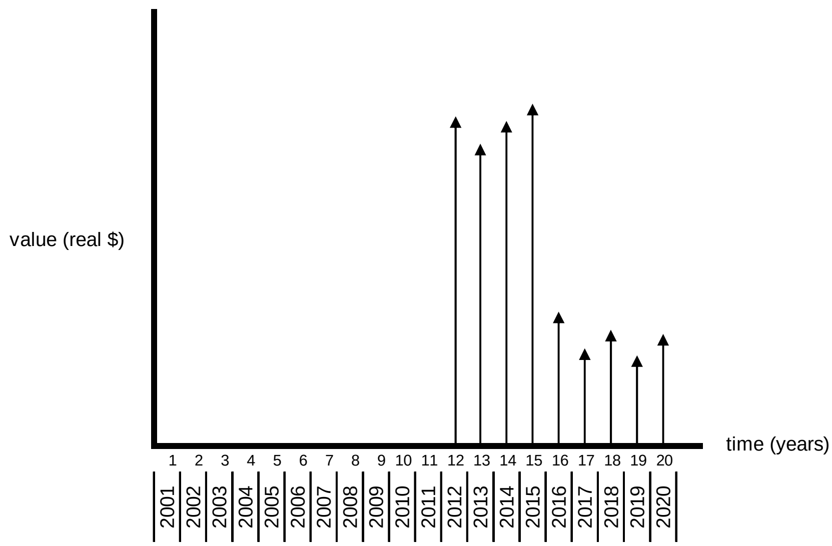
Example Problem

A coal plant goes into service in 2012. In 2016, a carbon penalty arrives. Figure J-14 illustrates the gross value of this power plant over time.

Figure J-14 is an illustration of a 20-year study that begins in 2001. The arrows correspond to dollar amounts of the annual value of energy in the market net of fuel and variable operating costs. (For the time being, ignore the fixed costs associated with this power plant.) After the carbon penalty appears, the gross value of this power plant goes down because the cost of fuel, including the carbon penalty, goes up.

The present value of these cash flows may overstate the value of the plant relative to alternatives with lower carbon emissions. The present value would not capture the cost of the carbon penalty over the remaining economic life of the plant. If the economics of the plant during the 20 year study, that is, between the years 2012 and 2020, are not representative of its lifecycle economics, a bad decision may result. There are alternatives to the coal plant for meeting regional energy requirements. Consequently, even a relatively small shift in the value may give rise to an improper ranking of alternatives.

Figure J-14: Study Gross Value for Coal Plant

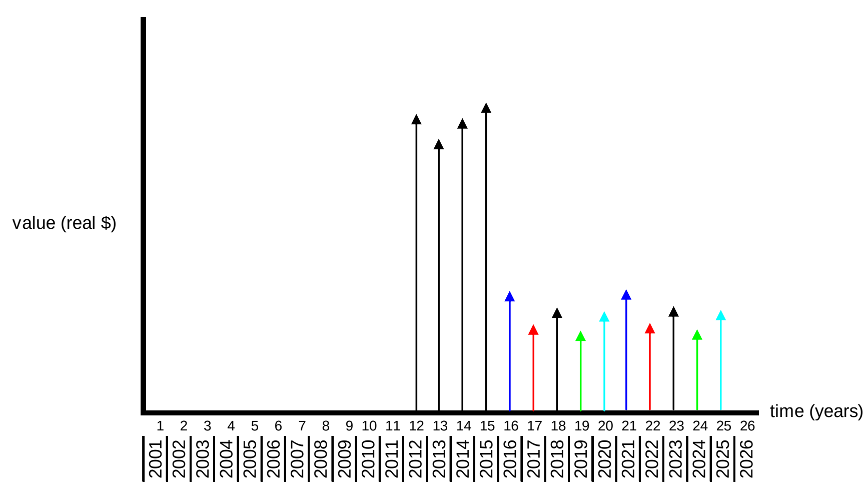


source: …\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

RPM Solution

One rather natural way to capture the economics of this resource beyond the study is to use the periods after the arrival of the carbon penalty. In Figure J-15, the pattern of values after the carbon penalty appears simply repeats. The values are colored in this illustration to emphasize their cyclical nature.

Figure J-15: Extension of Penalized Values



source: …\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

The present value relationship between the cash flow in 2022 and that in 2017 is given in Equation J-1. The fifth power of the discount factor in the second term arises from the period of the cycle of values. Because the event occurs in period E and the study has S periods, the cycle length is equal to S-E+1, as the last term states. The same relationship holds between the cash flow in 2023 and 2018, 2024 and 2019, and so forth.

Equation J-1

$$V_{2022} = \frac{1}{(1+d)^5} V_{2017} = \frac{1}{(1+d)^{(S-E+1)}} V_{2017}$$

where

V_{2017} is the present value of gross value in 2017

V_{2022} is the present value of gross value in 2022

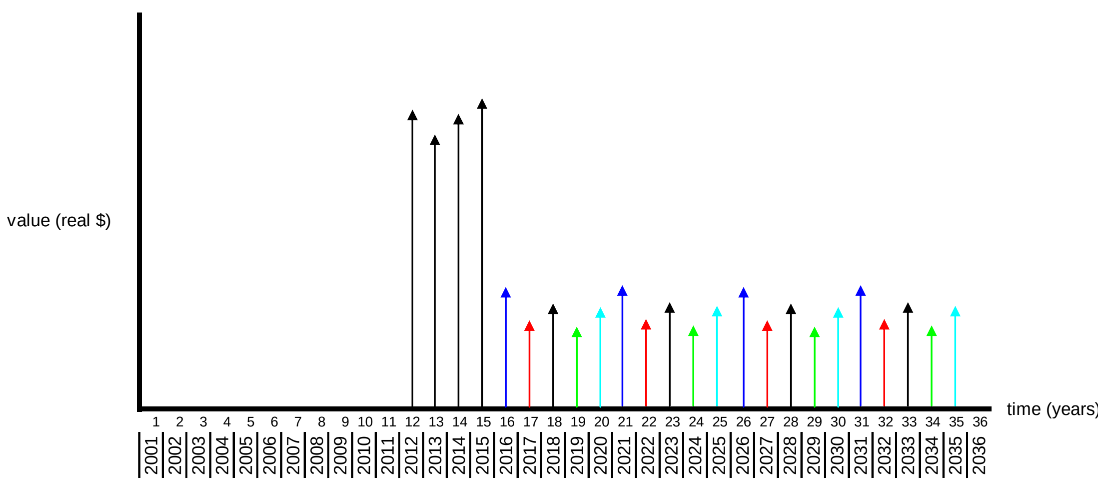
d is the discount rate

S is the last year of the study

E is the year in which the carbon penalty arrives

By repeating the cycle of values, the value over the plant's remaining life is obtained. Assume the plant' economic life ends after 2035. Figure J-16, therefore, shows the extension of the cycle of values through that year.

Figure J-16: Extension of Values over Lifetime



source: ...\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

Now the relationship of the present value of the cash flow in 2027 to that in 2022 is the same as that between the cash flow in 2022 and 2017, namely Equation J-1. Let the variable W denote the conversion factor in Equation J-1. The present value in 2017 of cash flows in 2017, 2022, 2027 and 2032 is then Equation J-2.

Equation J-2

$$V_{2017} + V_{2017} \times W + V_{2017} \times W^2 + V_{2017} \times W^3$$
$$= V_{2017} \times (1 + W + W^2 + W^3)$$

Again, the same relationship holds for corresponding subsequences beginning in 2016, 2018, 2019, and 2020.

Equation J-3 simply states the present value to 2001 of the terms from 2016 to 2020.

Equation J-3

$$
\begin{aligned}
&NPV_{2001}(V_{2016},\cdots V_{2020}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} + \frac{V_{2017}}{(1+d)^{(2017-2001)}} + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}}
\end{aligned}
$$

Denoting $(1+W+W^2+W^3)$ by G, the present value of cash flows in Figure J-16 from 2016 through 2035 back to the beginning of the study is Equation J-4

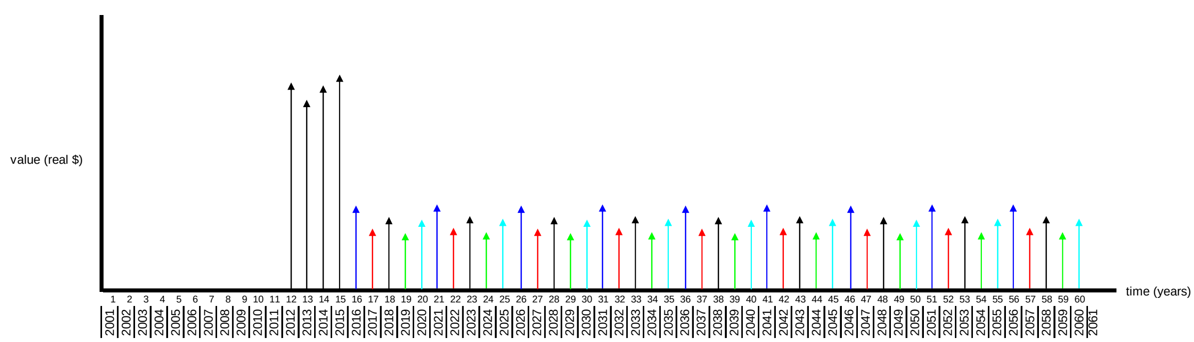
Equation J-4

$$
\begin{aligned}
&NPV_{2001}(V_{2016},\cdots V_{2035}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times G + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times G + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times G \\
&= NPV_{2001}(V_{2016},\cdots V_{2020}) \times G
\end{aligned}
$$

The effect associated with carbon penalty is now reduced to a single multiplier. The multiplier applies to the present value of cash flows in the study subsequent to the carbon penalty.

This solution, however, does not address the problem if a power plant does not have exactly this economic life time or if there are alternative resources with distinct economic lives. One solution to this is to extend the cycle and the evaluation horizon indefinitely. That is, mathematically it is meaningful to extend the cycle of values to infinity. (See Figure J-17.)

Figure J-17: Indefinite Extension



source: ...\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

How do we interpret the extension of cash flows associated with our coal plant beyond its economic life? It is customary to assume replacement in kind. From a present value standpoint, contributions beyond the economic life of a typical power plant from replacements are small.

The sum of an infinite series of powers of a variable is called the geometric series. (See Equation J-5):

Equation J-5

$$
\sum_{i=0}^{\infty} x^i = 1 + x + x^2 + x^3 + \cdots = \frac{1}{(1-x)}, \quad 0 \le x < 1
$$

The adjustment to the net present value of cash flows after the carbon penalty is therefore multiplication by a fixed constant (See Equation J-6).

Equation J-6

$$\begin{aligned}
&NPV_{2001}(V_{2016}, V_{2017}, \cdots, \infty) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times \Pi + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times \Pi + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times \Pi \\
&= NPV_{2001}(V_{2016}, \cdots V_{2020}) \times \Pi \\
&\text{where } \Pi \text{ is the "perpetuity factor," } \frac{1}{1\text{-}W} = \frac{1}{1\text{-}\left(1+d\right)^{(E-S-1)}}
\end{aligned}$$

It would be convenient to replace the net present value of cash flows over the 20-year study with a similar formula that includes the extension to perpetuity. To do so, start with the general statement in Equation J-7:

Equation J-7

$$NPV_{2001}(V_{2016}, \cdots V_{2020}) = NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})$$

Equation J-7 replaces the term $NPV_{2001}(V_{2016}, \ldots, V_{2020})$ in Equation J-6 with the difference between two present values that both begin with the first cash flow of the study. Then $NPV_{2001}(V_{2001}, \ldots, \infty)$ is the left-hand side of Equation J-6 plus another present term, $NPV_{2001}(V_{2001}, \ldots, V_{2015})$, that begins with the first cash flow of the study.

Equation J-8

$$\begin{aligned}
NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) &= NPV_{2001}(V_{2001}, \cdots V_{2015}) + \\
&\quad \left[NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})\right] \times \Pi \\
&= \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + (1-\Pi) \times NPV_{2001}(V_{2001}, \cdots V_{2015})
\end{aligned}$$

The Excel OFFSET() function can make this formula more flexible. It permits the user to begin the perpetuity sample period in any year (Equation J-9). If the period that the carbon penalty arrives changes, the model need only update the value of variable ***E*** in Equation J-9.

Equation J-9

$$\begin{aligned}
NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) &= \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + \\
&\quad (1-\Pi) \times NPV_{2001}\left(\text{Offset}\left(\left[V_{2001}, \cdots V_{2020}\right], 0, 0, 1, E-1\right)\right)
\end{aligned}$$

This modification of the standard NPV formula applies to every cash flow in the model. Because the model uses valuation costing, it must be applied therefore to the cost of load valued in the power market, as well as to all fixed costs.

To avoid burdening the reader with even more technical explanation, suffice it to say that there are problems with tying the perpetuity sample period to the arrival of the carbon penalty. The perpetuity sample period is the period ***E*** above through the end of the study. All of the modeling up to the final model tied the perpetuity sample period to the arrival of the carbon penalty.

The final version of the model uses a fixed sample period, the last two years of the study. With this approach, power plants are prohibited from completing construction in the last two years. The carbon penalty is likewise forced to occur before the perpetuity sample period or not at all. These constraints are largely unnecessary, however. In the unconstrained model, no plant completes construction in the last two years. Only 0.5 percent of the futures have a carbon penalty that arrives in the last two years.

It should be noted that the approach adopted for the final Plan may overstate the requirement for combustion turbine licensed and permitted in the out years. The least-risk resource portfolio from the Carbon Risk scenario calls for nine 415 MW units by the end of the study. In the draft plan, the portfolio from the same point on the efficient frontier of the Carbon Risk scenario called for two combined-cycle combustion turbines by the end of the plan. Studies without the perpetuity adjustment called for even fewer combined-cycle combustion turbines by the end of the plan. (In other respects, specifically the market adders for conservation and the value of renewables, the results are nearly identical.) There is reason to believe the perpetuity adjustment is responsible for these differences. If there are unsustainable excursions in electricity price or in other uncertainties in the perpetuity sample period, those excursions will have disproportionate effect on NPV total system cost.

Given these observations, prudence favors the lower estimate of permits for the combustion turbines. The perpetuity adjustment arose from a specific perceived problem. The problem was the treatment of economics for coal plants, and other fossil fuel plants, where carbon penalties arise after the coal plant is in service. This situation, however, is virtually absent in the final plan. The Council's carbon penalty probability distribution makes it unlikely for new fossil-fired plants to come into service before the carbon penalty. Across the 750 futures in the least-risk Carbon Risk resource portfolio, it never happens to a combined-cycle combustion turbine. It happens in only 3.1 percent of the futures to simple-cycle combustion turbines[13]. The Council excludes conventional coal plants as new resource candidates. Under these circumstances, modeling ***without*** the perpetuity factor adjustment probably gives us the fairest assessment of risk and of the need for new resources. These considerations, however, have little immediate significance. The earliest regional construction that the model calls for begins in December 2015, with ground breaking for two 85 megawatt simple-cycle combustion turbines.

Modeling Energy-Limited Resources

Chapter 5, ***Demand Response***, describes resources that run only a brief number of hours each year. The number ranges from 40 to 100 hours per year. These resources were not in the Fifth Power Plan. To model this kind of resource, new algorithms were necessary. This section summarizes the new technique.

Appendix L of the Fifth Power Plan describes how the model uses statistical distributions of hourly fuel and electricity market prices to estimate dispatchable power plant energy production and value. The section entitled, ***Thermal Generation***, beginning on page L-26 of Appendix L, is prerequisite to understanding this discussion.

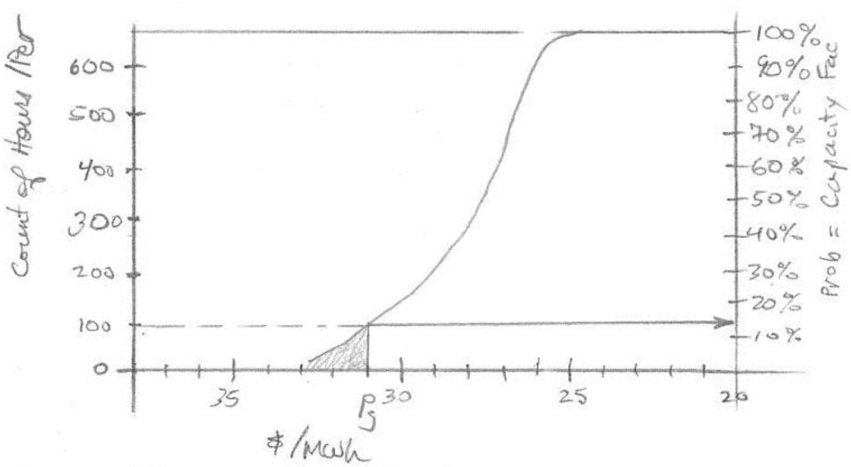
13 Source: "…\Plan 6\Studies\L813\Event statistics 091223.xls". See also "…\Plan 6\Studies\Model Development\CO2 tax end effect\Frequency of carbon penalty and unit completion.xls" for analogous draft Plan resource portfolio information.

Figure J-18 presents an example that will illustrate the algorithm. The curve in this figure is a price duration curve for wholesale power prices over some period. For this example, the period will be one month. Assume a particular generating unit exists that dispatches at electricity prices above $31 per megawatt hour. That is, it has fuel price and heat rate that makes dispatch profitable at that price. The capacity factor of the unit corresponds to the number of hours of operation out of the number of hours in the month. According to the figure, this would be about 15 percent of the hours. Whenever it is cost effective to generate, the economic choice is to generate at full capacity. Thus the capacity factor and the unit capacity yield amount of energy produced. The value of this generation is the shaded area to the left of the dispatch price.

Consider now a different electricity price duration curve, illustrated in Figure J-19, resulting from higher power prices. Given the same dispatch price, the figure suggests the unit would now dispatch in 60 percent of the hours or about 400 hours. In Figure J-19, the dotted line passing though the point on the price duration curve directly above the dispatch price now hits 60% on the right.

With the higher electricity prices, what would happen if the unit could run no more than 200 hours in a month? This constraint corresponds to a 27 percent capacity factor. It is represented by the solid horizontal line in Figure J-19. In this case, the economic choice for this unit is to run over that 200 highest-value hours. This creates the value corresponding to the shaded area in Figure J-20 beneath the horizontal line and to the left of the dispatch price, just as before.

Figure J-18: Price of Fuel Determines Energy Production



To calculate the value of the generation is to estimate area to the left of the dispatch price in the model. Start by finding the price $\boldsymbol{p_g}$***** that would give the same energy-limited capacity factor if the hours of operation were not constrained. This price appears in Figure J-21.

Figure J-19: Constraint on Energy

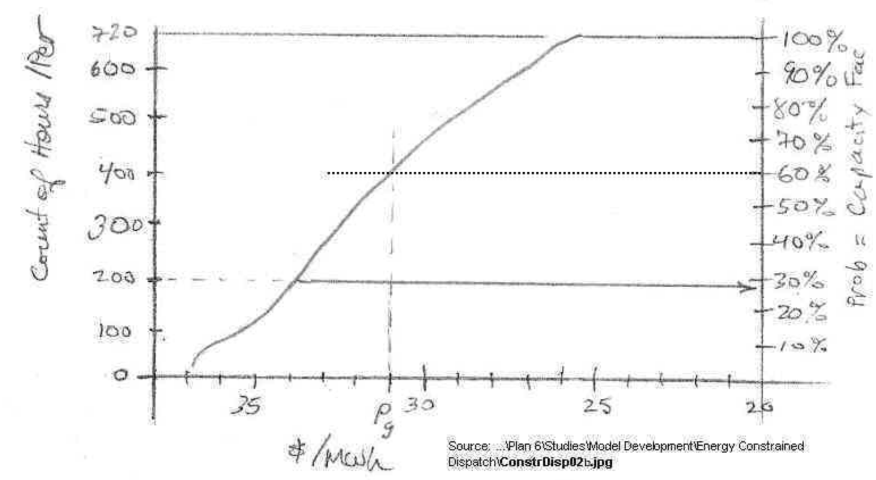


Figure J-20: Value Produced

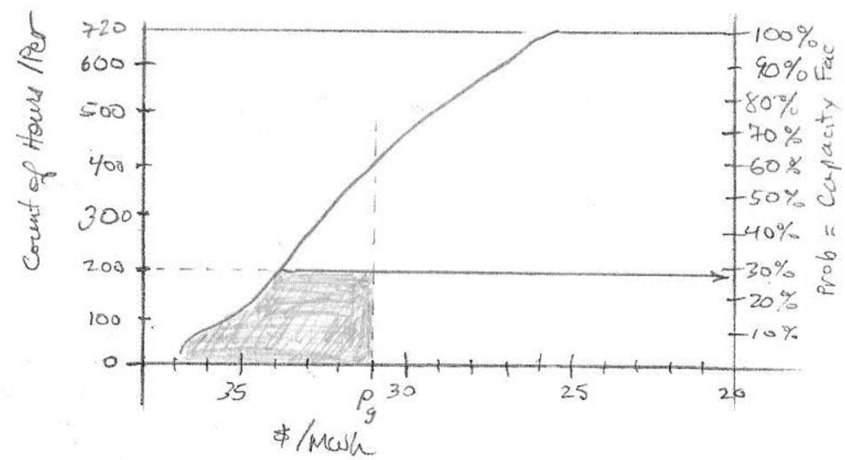
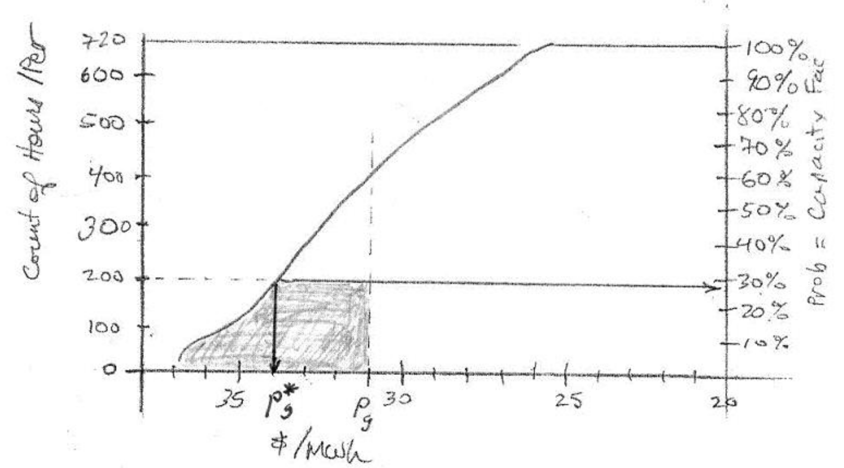


Figure J-21: Fuel Price Corresponding to Energy Constraint



It turns out that if the energy-limited capacity factor is fixed, finding $\boldsymbol{p_s}^*$ is straightforward. It is also robust. The model can estimate the relationship once, at the beginning of the simulation, and quickly update the value of $\boldsymbol{p_s}^*$ for each calculation.

In application, the model simply compares $\boldsymbol{p_s}^*$ against the price of fuel $\boldsymbol{p_g}$ in that period. If $\boldsymbol{p_s}^*$ is **greater than** the price of fuel, the hours and energy are constrained and the model uses $\boldsymbol{p_s}^*$ to determine the generation and value of the energy. If $\boldsymbol{p_s}^*$ is **less than** the price of fuel, the hours and energy are unconstrained. The model then uses the price of fuel $\boldsymbol{p_g}$ to determine energy generation and value as it normally would in the unconstrained case.

Estimating the area to the left of the dispatch price $\boldsymbol{p_g}$ in the constrained case is also simple. The model routinely calculates the area to the left of dispatch prices in the unconstrained case. It has efficient ways to do that. If can therefore quickly calculate the area to the left of $\boldsymbol{p_s}^*$. The area corresponding to value in the constrained case then is the area to the left of $\boldsymbol{p_s}^*$, augmented by a rectangle of value between $\boldsymbol{p_s}^*$ and $\boldsymbol{p_g}$. The height of the rectangle is the number of hours constrained. The area of the rectangle is therefore also known.

Quantitative Risk Analysis

Studies of the RPM results provide insights into the economic risk for the region. The following summarizes findings about the correlation of and sensitivity of system cost to sources of uncertainty.

The term "correlation" may require explanation. It refers to the strength of the relationship between the uncertainty and cost. For example, a plot of the time that students spent studying a topic and their scores on their test would not show a straight-line relationship. Instead, there would be a cloud of points. The correlation is a measure of how tightly the cloud clusters around the trend line. It tells us how much the variable "study" explains the result ("test score"). The sensitivity, on the other hand, is the slope of the line. Correlation is an aspect of the data that is largely independent of sensitivity. In this study, the t-statistic is the primary measure of correlation.

The following describes the explanatory variables in this study. The selection of these variables is the result of examining many models. The value of R^2 measures of much variation the model explains. The strategy for selecting variables is to increase R^2 until other statistical tests indicate the model has too many variables.

Cost – The dependent variable ($M) representing all variable costs of the existing and new system. The dependent variable does not show up explicitly in the results. It is the variable against which the other variables are regressed. The analysis uses quarterly cost from the RPM. Separate studies are performed for on- and off-peak costs.

CO2_Penalty – The carbon penalty ($2006per ton **e**$CO_2$) discussed throughout the Plan.

NGP_East ($2006/MMBTU) – The cost of natural gas delivered to power plants east of the Cascades, where most of recent capacity additions have been made and future additions are likely.

ELP – Electricity price ($2006 per megawatt-hour), east of the Cascades, where much of the generation resides. Electricity price on peak is denoted **ELP_NP**; electricity price off peak is denoted **ELP_FP**

Position – System energy load requirements in terawatt hours (TWh = MWh x 10^6). These particular elements of load requirements, however, are insensitive to power market prices. Position on peak is denoted **Position_NP**; position off peak is denoted **Position _FP**

Position is

- ✓ Non-DSI power load
- ✓ DSI power load

less

- ✓ conservation
- ✓ RPS resources (wind and geothermal generation)
- ✓ must run resources
- ✓ contracts
- ✓ hydrogeneration

Position is a measure of the system to which the remaining system (generation and imports/exports) must respond through power market price signals.

Position is a useful variable because loads, hydrogeneration, and the other variable are reduced to this value. To understand how cost responds to any of these, look to the role of this single variable.

Market – The product ($M) of market power price **ELP** and of **Position**. This variable tells us how much combinations of high prices and deficits add to cost. If low prices and surpluses contribute to cost, this variable is also significant. This is called an interaction term. The value of the Market variable on peak is denoted Market_NP; the value of the Market variable off peak is denoted Market_FP;

Adding the interaction term to the model permits the model to reflect the movement of these variables in the same direction. Consider, for a moment, the following product:

$$\left(Q-\overline{Q}\right)\left(p_e-\overline{p_e}\right)$$

where

Q is the position (MWa)

$\overline{Q}$ is the average position

p_e is the price of electricity

$\overline{p_e}$ is the average price of electricity

If Q and p_e ***both move below*** their average, each term is negative and the product is positive. Similarly, if Q and p_e ***both move above*** their average, the product is again positive. The product is negative only when the two variables move in opposite directions. If we included this product in the regression, therefore, its significance would indicate that the ***coordinated movement*** of the variables explains higher cost.

Table J-3 is the result of the regression analysis. There are separate analyses for on- and off-peak costs. The multiple R^2 for the on-peak model is over 95 percent; it is about 89.4 percent for the off-peak model. There is no indication of surplus variables[14]. All of the variables are highly significant, with that for CO_2 penalty standing out.

Table J-3: Regression Model Coefficients

on-peak model

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	62.63	1.49	42.15	0.00	59.71	65.54	59.71	65.54
Position_NP	22.02	0.17	126.49	0.00	21.67	22.36	21.67	22.36
ELP_NP	(8.23)	0.03	(314.43)	0.00	(8.28)	(8.18)	(8.28)	(8.18)
Market_NP	0.80	0.00	309.99	0.00	0.80	0.81	0.80	0.81
CO2_Penalty	7.59	0.02	465.22	0.00	7.56	7.62	7.56	7.62
NGP_East	31.93	0.16	203.77	0.00	31.63	32.24	31.63	32.24

source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Regression Analysis of L813 Costs**Regression_on_cost_L813LC_100228_00.xls, wksht "NP_Variables"**

off-peak model

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	7.64	0.81	9.48	0.00	6.06	9.22	6.06	9.22
Position_FP	17.40	0.15	115.52	0.00	17.10	17.69	17.10	17.69
ELP_FP	(1.62)	0.02	(89.23)	0.00	(1.66)	(1.59)	(1.66)	(1.59)
Market_FP	0.59	0.00	189.85	0.00	0.59	0.60	0.59	0.60
CO2_Penalty	3.18	0.01	237.33	0.00	3.16	3.21	3.16	3.21
NGP_East	10.40	0.11	94.40	0.00	10.18	10.61	10.18	10.61

source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Regression Analysis of L813 Costs**Regression_on_cost_L813LC_100228_00.xls, wksht "FP_Variables"**

Some care is necessary in interpreting the coefficients. Their size depends on the chosen units. That is, if a variable for price is in cents rather dollars, the coefficient will be 100 times larger.

This table reveals the following. Every dollar increase in natural gas prices causes regional costs to go up \$39.42 million (22.02+17.40) per standard quarter[15]. For every dollar per ton CO_2 carbon penalty the region faces, cost increases \$10.77 million (7.59+3.18) per standard quarter. Every dollar per megawatt-hour that wholesale electricity prices go up, regional cost declines by \$9.85 million (8.23+1.62) per standard quarter. This is consistent with the observation that the region is modestly surplus over the study period. It does not take into account, however, the interaction term, Position, and therefore represents change only if Position were 0.0.

Position is the product of net requirement (loads – resources) and power price. The net requirement, however, does not include dispatchable resources. For each 1000 MW that a system deficit increases relative to this measure, cost rises \$1.43 million ((1000*1152*0.80+1000*864*0.59)/1,000,000) per standard quarter for each dollar per megawatt-hour that power market prices increase. They would *also* rise by this amount if market prices fell when the region was surplus an equivalent amount.

14 For the on-peak model, R Squared = Adjusted R Squared = 90.9%; for the off-peak model, R Squared = Adjusted R Squared = 79.9%

15 The standard quarters that the model uses has 12 weeks or roughly 92 percent of the hours in a calendar quarter. A standard quarter has 1152 hours on peak and 864 off peak. Upward adjustment is necessary for comparison with actual costs.

This brief analysis underscores the potential for market exposure and other uncertainties to affect cost and cost volatility. For even a modest firm deficit, the contribution from the interaction term Position dominates the wholesale electricity price effect. The next section illustrates these finding with specific examples.

Illustration with Selected Futures

This section presents two futures that have the potential for large risk under the Council recommended resource portfolio. The first is the most expensive future. It shows the risk of not anticipating large power requirements. The second future is one selected to show risk for the centerpiece of the Sixth Power Plan, conservation. It features low electricity prices and low requirements, and it results in a large surplus. Finally, an example features the same future as the last one, but where there is no conservation. Instead, the risk of inadequate resources has been met with combustion turbines.

The plan chosen for the first two illustrations is the least-risk plan from the Carbon Risk scenario. Chapter 9 introduces the ideas of a feasibility space and its efficient frontier. The efficient frontier for in the Carbon Risk scenario appears in Figure J-22. The schedule for the earliest construction of each resource in this plan appears in Figure J-23.

Figure J-22: The Efficient Frontier

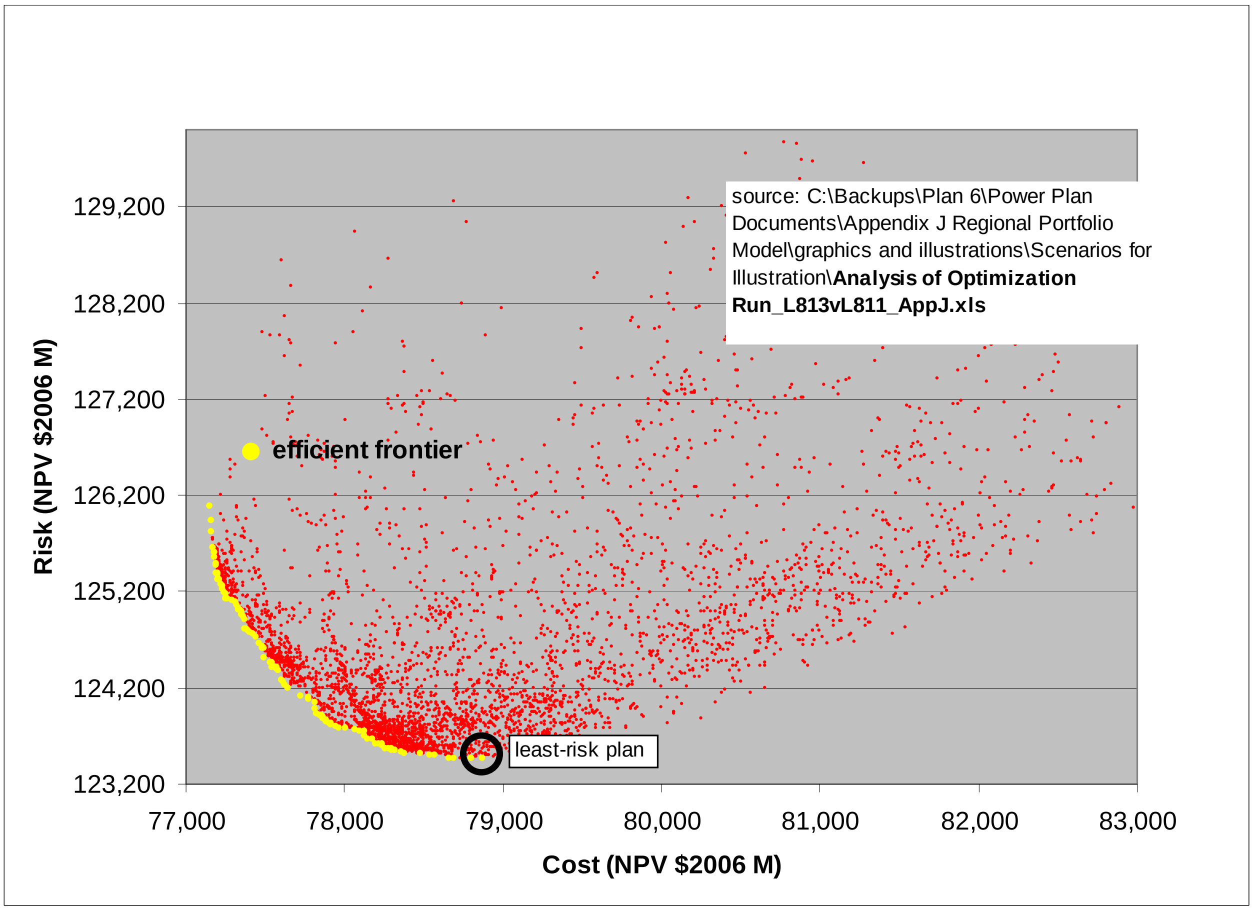


Figure J-23: Carbon Risk Least-Risk Resource Portfolio

50	**Lost opportunity** conservation cost-effectiveness threshold over market ($2006/MWh)
3092	**Lost opportunity** conservation by end of study (MWa)
80	**Discretionary** conservation cost-effectiveness threshold over market ($2006/MWh)
2867	**Discretionary** conservation by end of study (MWa) assuming 160MWa/year limit
5958	**Total conservation (MWa)**

Cumulative MW, by earliest date to begin construction

	Dec-15	Dec-17	Dec-19	Dec-21	Dec-23
CCCT	0	0	**3735**	**3735**	**3735**
SCCT	**170**	**170**	**680**	**680**	**680**
RPS Resources	**123**	**381**	**637**	**763**	**817**

Source: "Schedules for plan resources 100302.xls", worksheet "Schedules (3)"

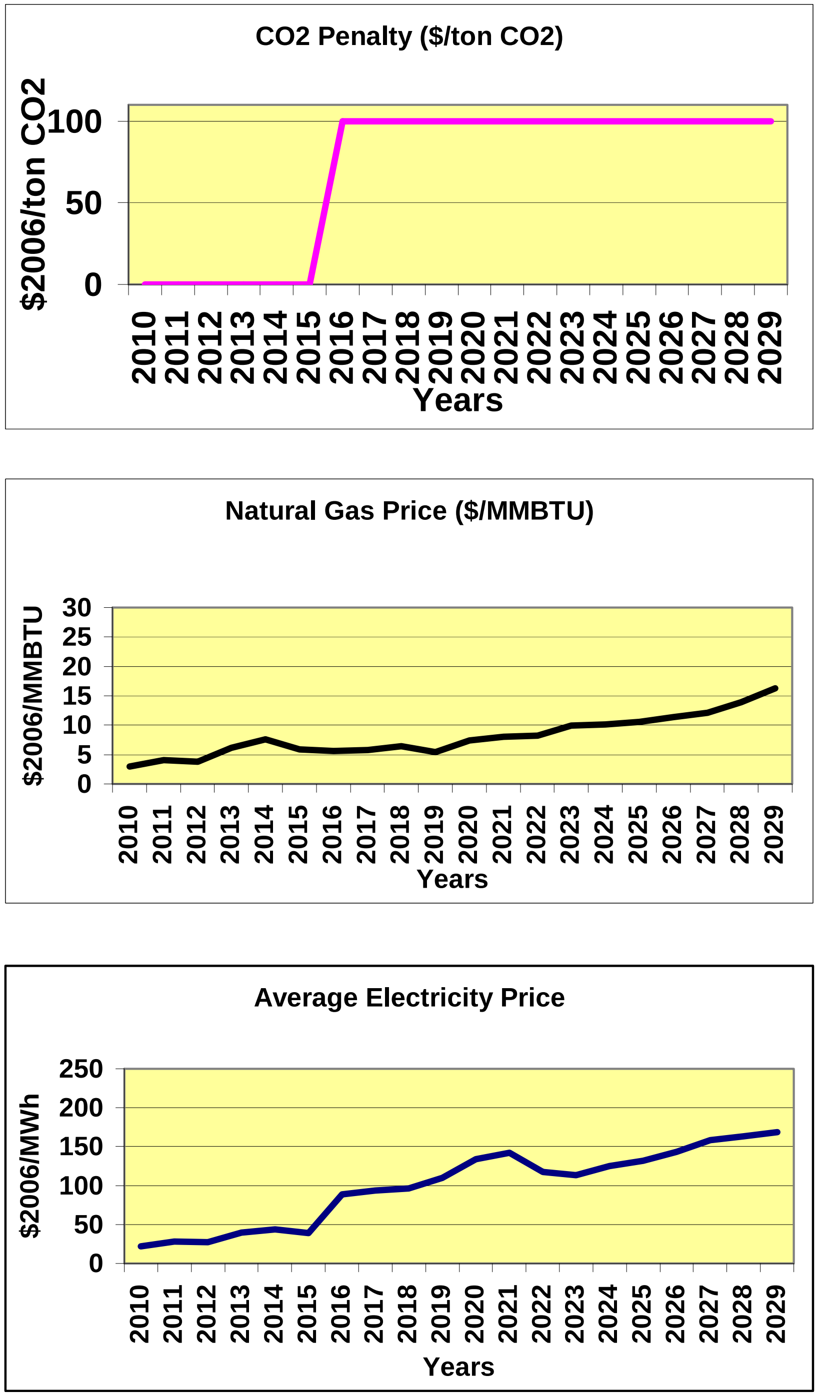
Exposure to Wholesale Power Markets

To see how market reliance affects costs, consider the future illustrated in Figure J-24[16]. High gas price and electricity prices, combined with high carbon penalty, create a treacherous outcome for the least-risk portfolio. While the average cost for this plan across futures, including carbon penalty, is $78.9 billion NPV, this future costs $ 222.4 billion.

Because of the high load growth and hydrogeneration shortages in several years, the region is forced to purchase power under unfavorable circumstances. (See Figure J-25) This occurs despite the construction and operation of the additional resources in the model's least-risk portfolio. While the region's energy adequacy metric shows a surplus from today's perspective, this future highlights the possibility that the region can nevertheless become exposed. The cost and rate excursions in Figure J-26 correspond directly to periods of low hydrogeneration and to high energy import levels.

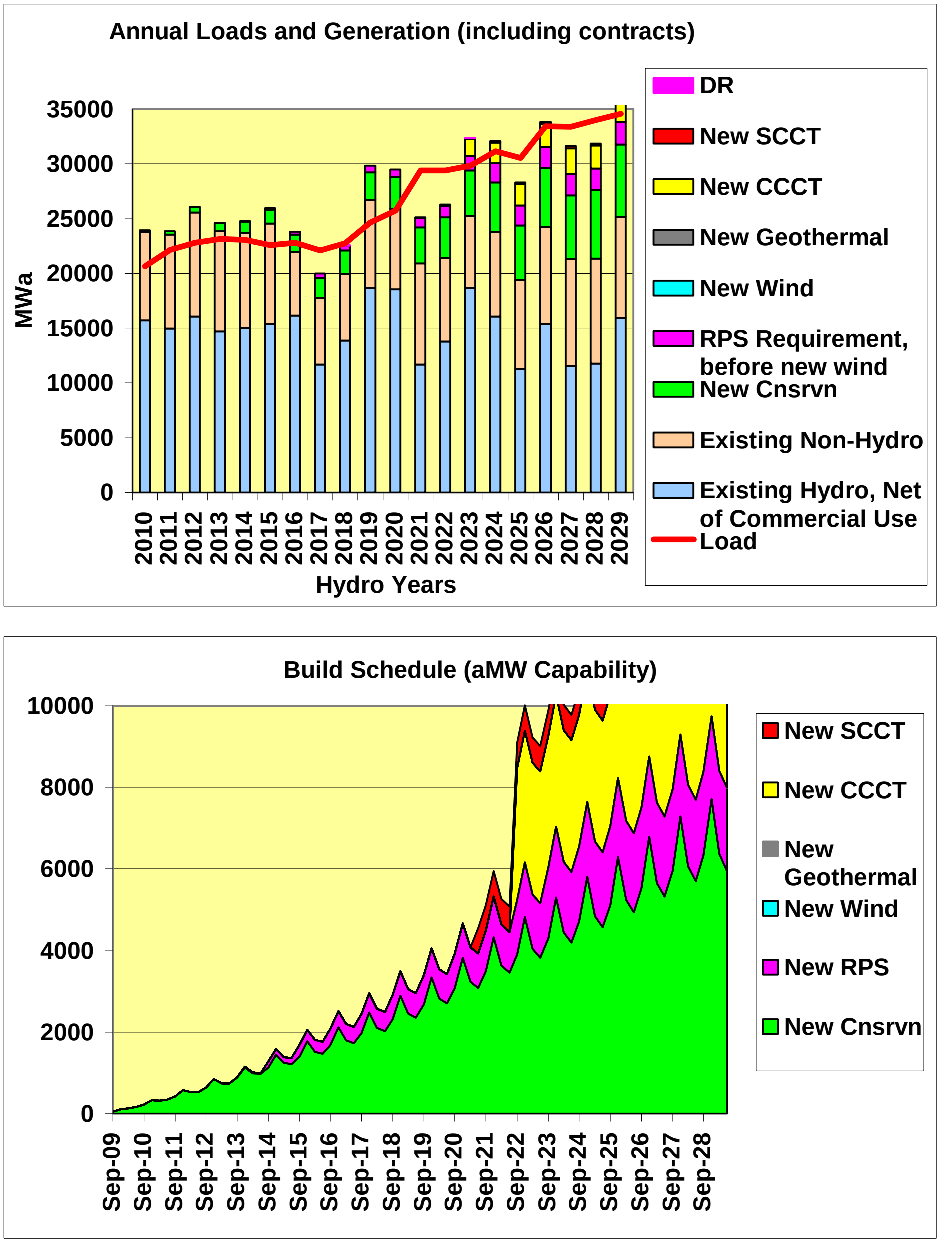
16 This future, number 150, and all of the other 749 futures – and their impacts on resource portfolios – may be viewed by down-loading "spinner graphs" from the Council's website. This example is from the Carbon Risk least-risk portfolio spinner graph, http://www.nwcouncil.org/dropbox/Spinner_091220_2157_L813_2990_LR.zip

Figure J-24: Elements of Future 150



source:...\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Scenarios for Illustration**Spinner_091220_2157_L813_2990_LR_for_AppJ.xls**

Figure J-25: Loads, Operation, and Build Out



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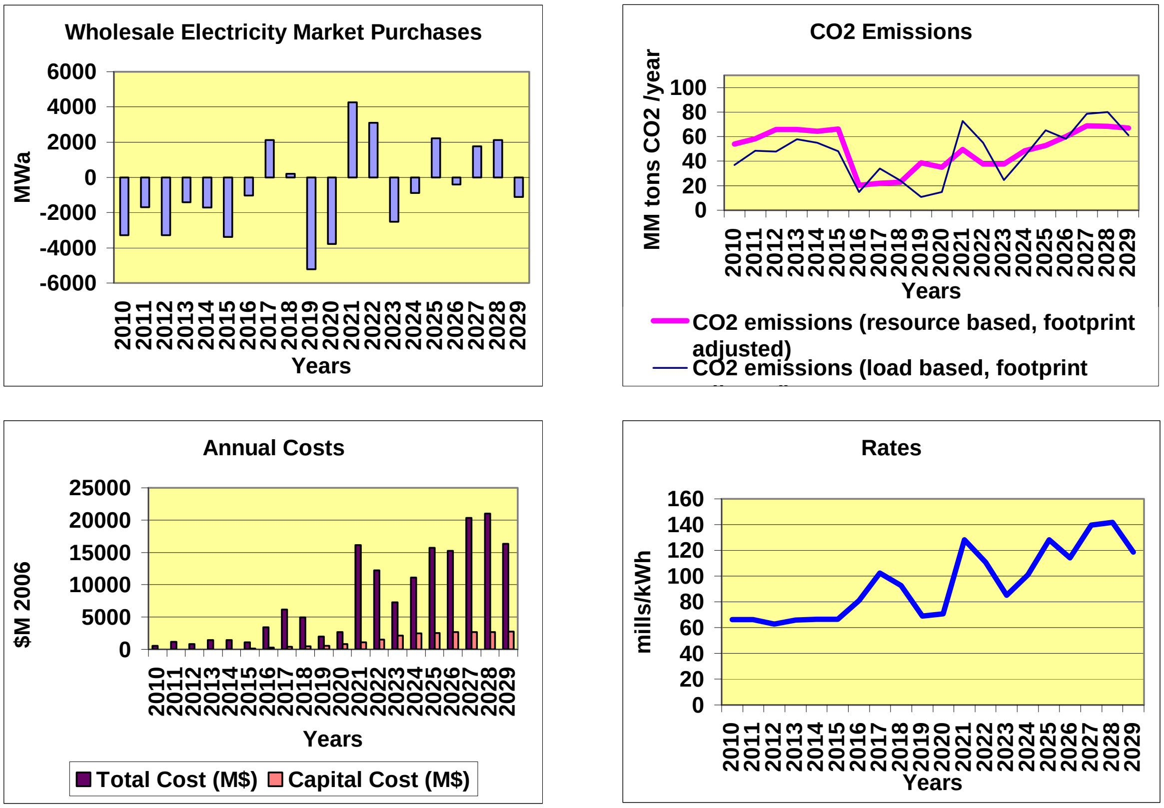
Finally, Figure J-26 shows that when electricity prices remain high and the region needs power, the coal plants in the region will run and emissions will remain high. Without the regional coal plants, the maximum regional CO_2 emission levels would never exceed 35 million tons per year. Even with a $100per ton carbon penalty, the CO_2 emission levels in the latter years of this scenario consistently run above today's levels.

Figure J-26: Other Consequences



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An obvious response to this risk might be to acquire enough resources to minimize the likelihood of exposure to the market. Depending on the selection of resources, however, this can present its own risks. Some resources will create greater cost, for example, if wholesale electricity prices crash.

In the second future, loads fall or remain flat, new resources are surplus to the region’s needs, and low market prices occur. The performance of two plans under this future reveals the difference that resource choice can make. The first plan under the new future is the same plan as before, the least risk plan from the Carbon Risk scenario

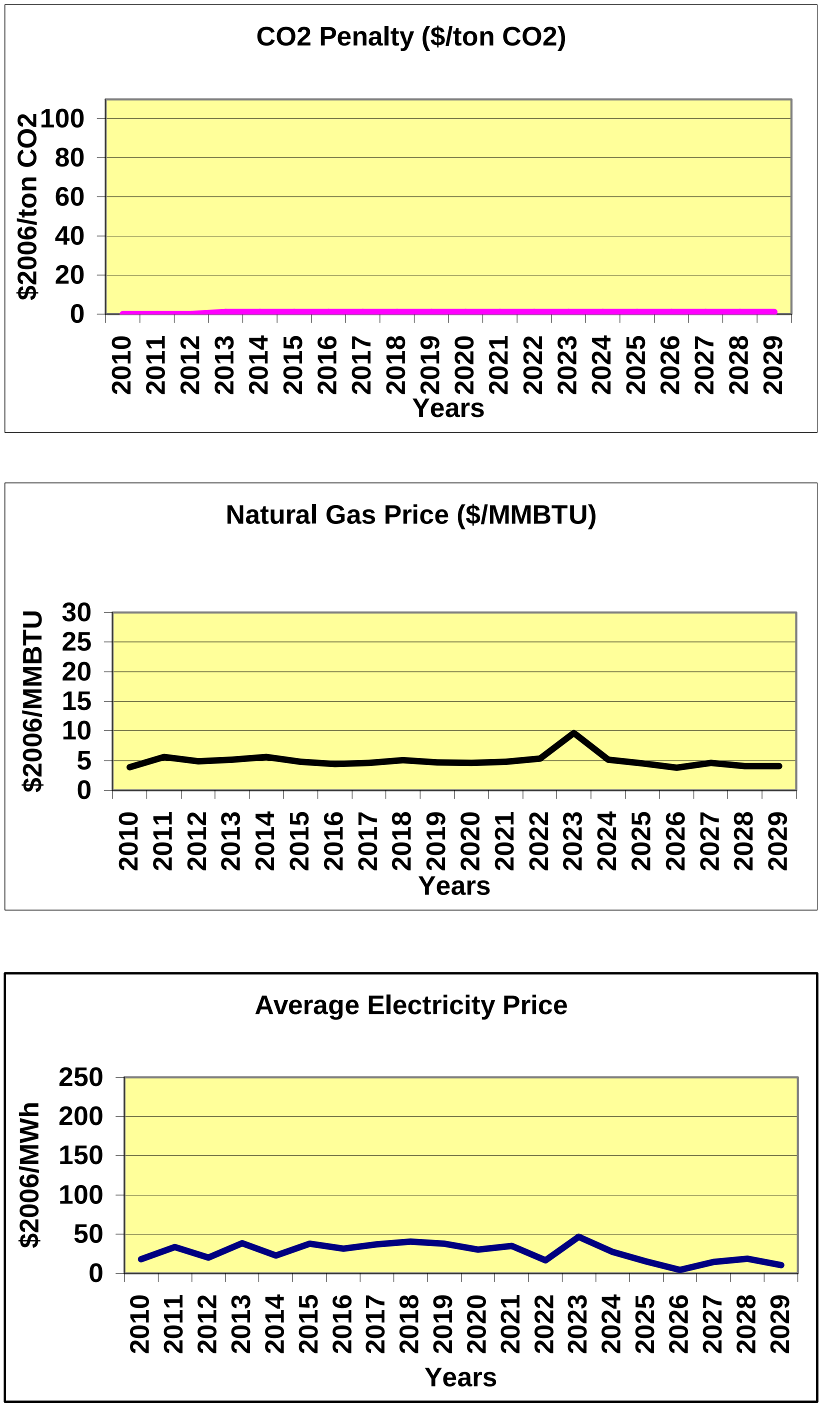
Conservation Value in Surplus Power Markets

The least-risk plan supports higher levels of conservation and conventional resource development. The risk associated with high levels of capital investment in conservation and generation resources is that the region turns surplus and electricity prices fall.

Selecting from among the lower load-growth futures, there are many in which load remains flat and electricity prices either hold or fall. The most extreme by these appears to be future 185. The following scenario is from the same spinner workbook as before.

Figure J-27 presents a future where natural gas and electricity prices remain about where they are today until the last five years of the study, when they soften. More significantly, load growth, illustrated in Figure J-28, is relatively flat. This results in significant surplus of resources in the out years, largely due to better-than-normal hydrogeneration conditions.

Figure J-27: Elements of Future 185



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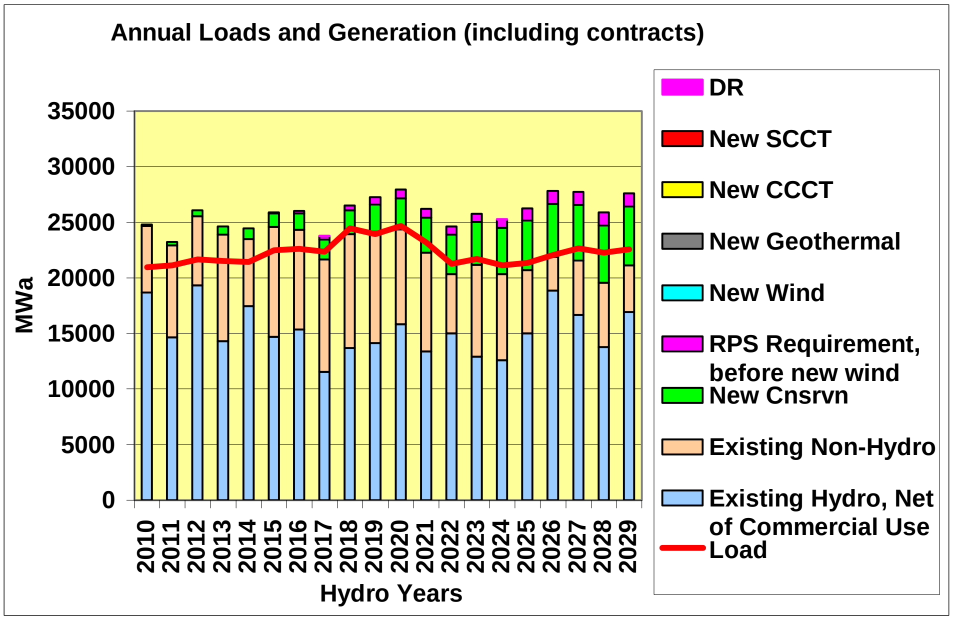
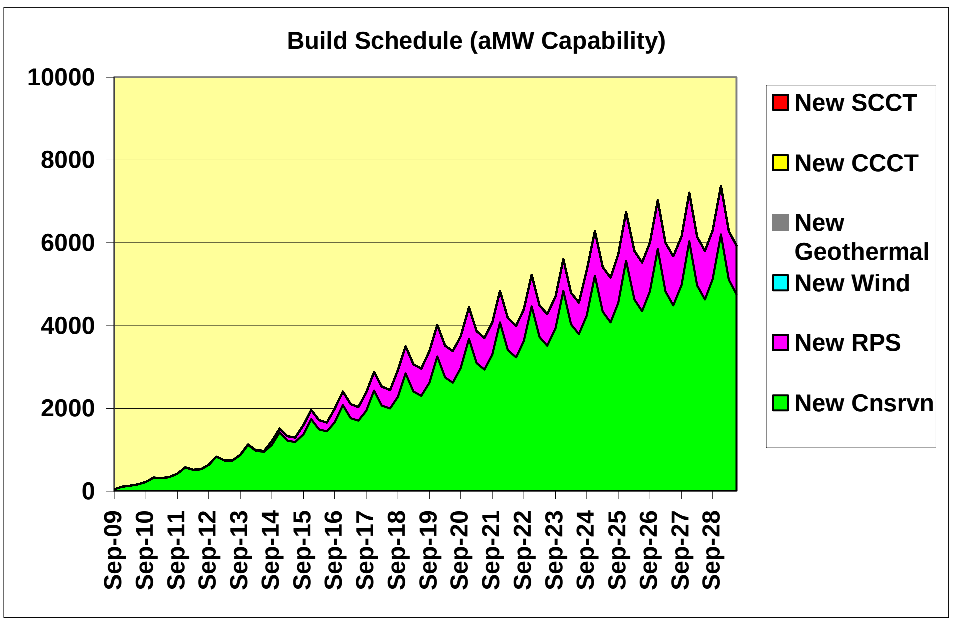
In response to generally lower electricity prices, the region does not construct the combustion turbines that have been sited and licensed in the portfolio. Lower electricity prices result in little generation beyond the must-run units. Must-run gas-fired generation is mostly customer cogeneration installations and units necessary to provide for system stability. On an energy basis, the RPS and conservation that the region has built is surplus to its requirements.

Figure J-28: Loads, Operation, and Build Out of Future 185





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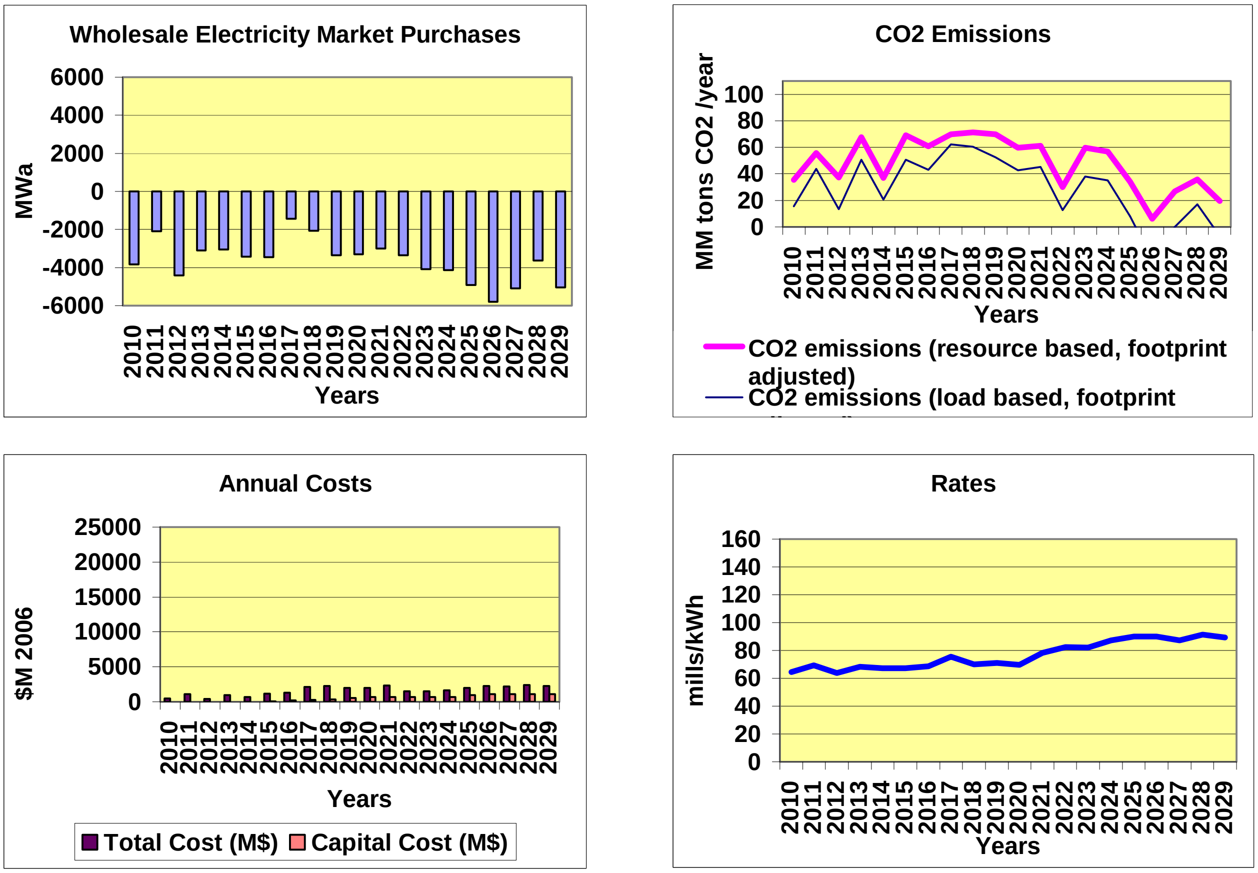
Despite this extreme set of circumstances, the total cost of the system is $40.3 billion. This figure is less than the expected cost for this plan across futures. Evident in Figure J-29 is reduced cost and rate variation and CO_2 emissions.

The advantage of conservation and, to a lesser extent renewables, is a low or zero operating cost. At any electricity price, these resources contribute some level of value. Figure J-29 shows that, while thermal generation is shut down, the region is still exporting surplus energy and reducing annual costs. Revenue requirements are only about 2 mills per kWh higher than average.

Lower costs are to be expected, however, in a future with low loads and low market prices. The question is, could the region have done better by building conventional thermal resources? The third example sheds light on the answer.

Figure J-29: Consequences of Future 185



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A Plan without Conservation

The Council performed a study with the same assumptions as the first plan presented above, except that no conservation was available to the model. As before, the study included RPS resources and the $0-100 per ton stochastic carbon penalty. The schedule for the earliest construction of each resource in this plan appears in Figure J-30. Without conservation, RPS requirements are slightly higher.

As mentioned above, this is the same future as the one in the preceding example, number 185. Figure J-27 summarized several of the key aspects of this future.[17]

17 The spinner graph that this scenario is from can also be downloaded: http://www.nwcouncil.org/dropbox/Spinner_091223_1348_L813a.zip

Figure J-30: No-Conservation Least-Risk Resource Portfolio

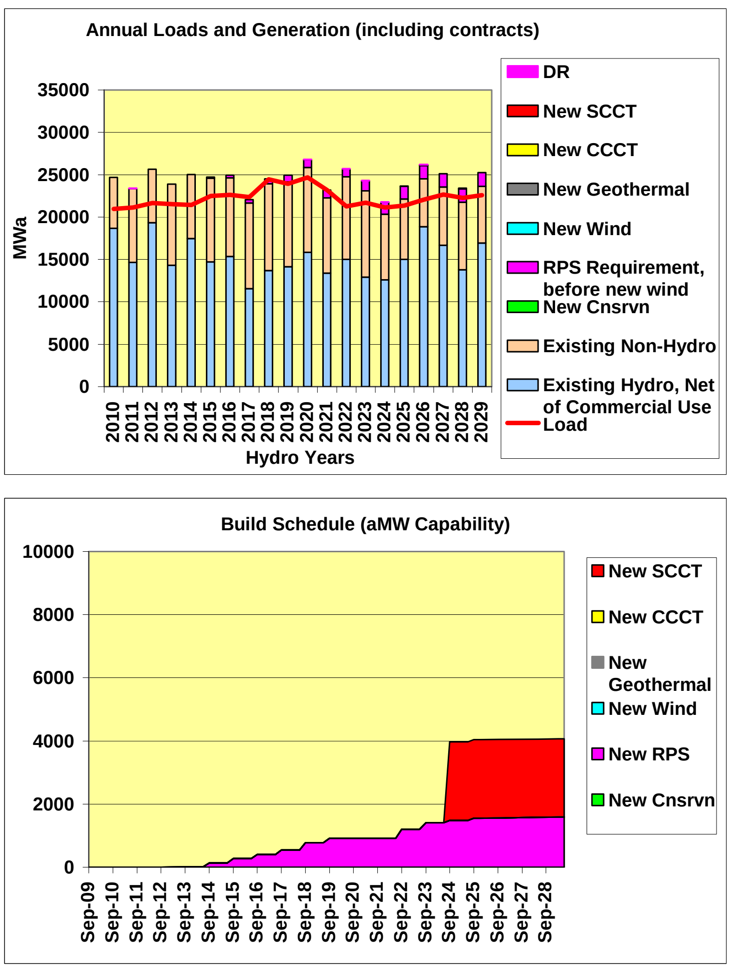
Cumulative MW, by earliest date to begin construction

	Dec-09	Dec-13	Dec-15	Dec-17	Dec-19	Dec-21	Dec-23
CCCT	0	**4150**	**4565**	**4565**	**12035**	**12035**	**12035**
SCCT	**170**	**170**	**170**	**340**	**340**	**3060**	**3060**
RPS Resources	0	**1**	**156**	**450**	**758**	**927**	**1502**

Source: "Schedules for plan resources 100302.xls", worksheet "Schedules (4)"

The model's plan has responded to circumstances about as well as could be desired. Loads and electricity prices have signaled utilities not to build the combined-cycle combustion turbines. (By design, the decisions in the model are not always so fortunate. The decisions imitate forecasts without perfect foresight.) This leaves only the single-cycle units for reliability and unforeseen events.   These single-cycle units run very few hours. The capacity factors never reach five percent, averaging closer to two percent. Figure J-31 presents salient features of system operation.

Figure J-31: Loads, Operation, and Build Out of Future 185 for the No Conservation Plan



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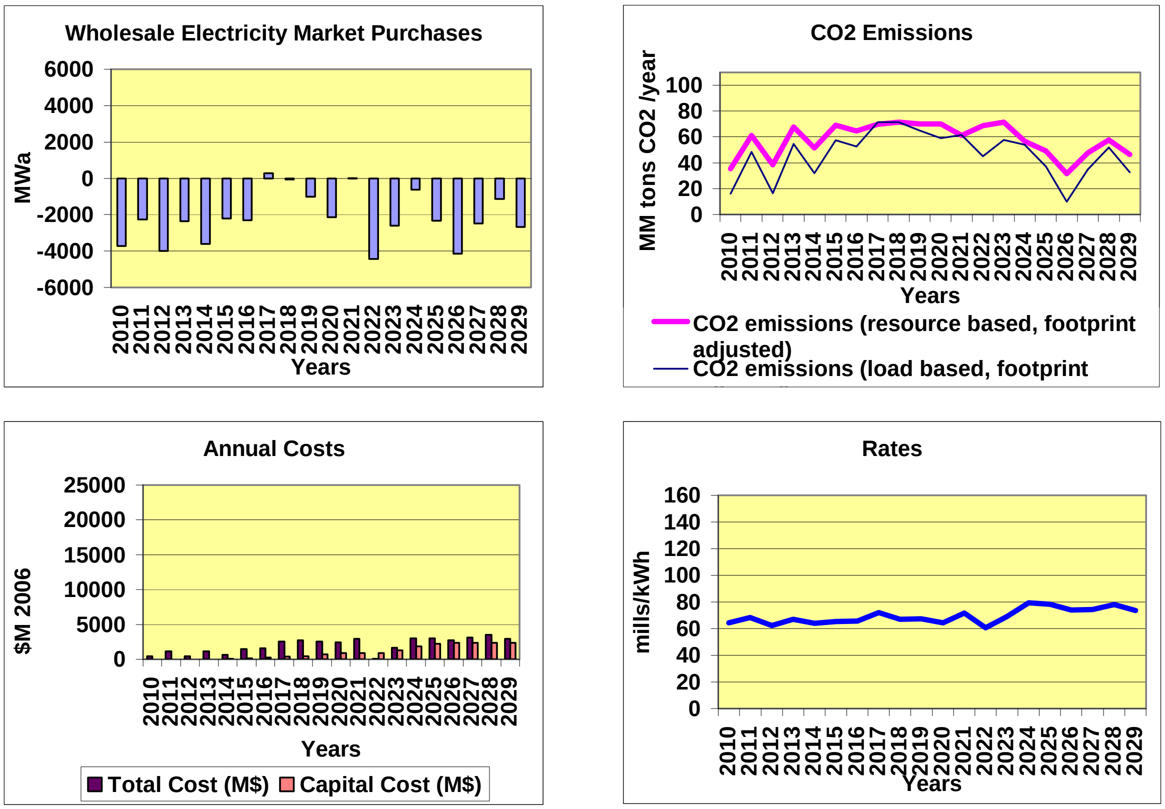
Many of the consequences of future 185 to this plan appear in Figure J-32. Two things to notice are the rates (revenue requirements) and the emissions. The rates are lower with this plan by 15.6 mills per kWh, about 17 percent. Of course, customers pay bills, not rates, and the bills will be roughly 23 percent *higher* with this plan. We know this because the net present value costs for the no conservation plan are $9.3 billion higher under this future.

Carbon emissions are much higher with the "no conservation" plan. Fortunately for this scenario, there is no carbon penalty or the contrast in cost with the first plan would be even starker.

Figure J-32: Consequences of Future 185 for the No Conservation Plan



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Collectively, these three scenarios demonstrate why there is a market adder for conservation. It is better to have slightly too many resources than too few. Most utility planners understand the value of keeping some capacity in reserve for unforeseeable circumstances. Examining the candidates for such a reserve, conservation is expected to be the best choice. These examples suggest that conclusion; Council studies support it. If the region develops only conservation that is less expensive than wholesale power, however, where would such a reserve come from? Wouldn't utilities want to meet ***expected*** energy requirements with this inexpensive resource? Going up the conservation supply curve ***above*** wholesale market prices – using an adder – provides the additional energy.

This additional conservation energy is more expensive on a real levelized basis than wholesale power. Traditionally, low capital cost-high operating cost resources like combustion turbines serve the role of providing reserves. It seems at first counterintuitive that conservation would be a good choice for reserves.

Conservation is the least expensive candidate for reserve energy and capacity precisely because it performs better in futures where electricity prices *are lower*. Such futures, in turn, are more likely if the region takes a low-risk approach to selecting its resource portfolio. A low-*risk* portfolio will have more resources than a low-*cost* portfolio, and additional resources will tend to produce lower and more stable power market prices. Conservation performs better in these situations because it has value even at low power prices, whereas dispatchable resources provide no value. In high price scenarios, of course, conservation performs no worse than dispatchable generation.

This is not to say that the region can add conservation without limit and not increase risk. Quite the contrary is true. At some point, additional conservation will *increase* economic risk. The role of the model is to help the Council find the prudent level of and best policy for acquiring this resource.

The Fifth Power Plan also presented many examples of how a least-risk plan reduces rate and cost volatility and market exposure. Council studies have confirmed that the same kinds of behavior take place with Sixth Power Plan's resource portfolios.

GENERATION RESOURCES IN THE MODEL

This section identifies generation resources assumed operating currently in the region. Existing resources in the RPM are aggregated by heat rate, fuel type, fuel source, technology, and variable operations and maintenance (VOM) rates. The following table lists each unit's capability in average megawatts and the aggregate unit with which it is associated. The capability includes discounting for planned and unplanned (forced) outages.

While it is not indicated here, a portion of certain plants may belong to independent power producers (IPPs). Those portions appear explicitly Chapter 9.

Table J-4: Existing Resources

Unit (New Name)	Aggr_Unit	Capability (MWa) after POR and FOR
18th Street (Springfield ICs, Springfield Gen Farm)	West 3	8.7
Barber Dam	Must Run	1.0
Basin Creek group	East 4	16.3
Beaver 1 - 7	West 3	417.0
Beaver 8	East 7	20.7
Bennett Mountain	West 4	151.4
Bettencourt Dry Creek Dairy	Must Run	2.1
Big Hanaford CC1A-1E	West 1	208.1
Biglow Canyon I	Must Run	37.7
Biomass One 1 & 2	Must Run	21.0
Boardman	Boardman	401.5
Boulder Park 1-6	East 4	22.0
Box Canyon	Must Run	0.3
Box Canyon 1 & 2	Must Run	1.6
Broadwater	Must Run	1.0
Bull Run No. 1 (Portland Hydro)	Must Run	10.7
Bull Run No. 2 (Portland Hydro)	Must Run	6.2

Bypass	Must Run	1.5
Central Oregon Siphon	Must Run	2.8
Centralia 1	Centralia	613.1
Centralia 2	Centralia	613.1
Chehalis Generating Facility	West 1	436.3
City of Albany (Vine Street WTP)	Must Run	0.2
Clearwater Hatchery (Dworshak)	Must Run	0.5
Coffin Butte 1 - 5	Must Run	4.8
Cogen II (D.R. Johnson) 1 & 2	Must Run	6.7
Colstrip 1	Colstrip 1&2	140.5
Colstrip 2	Colstrip 1&2	140.5
Colstrip 3	Colstrip 3&4	474.0
Colstrip 4	Colstrip 3&4	623.0
Columbia Generating Station	Must Run	996.1
Combine Hills I	Must Run	12.3
Condon	Must Run	15.0
COPCO 1 (1 & 2)	Must Run	12.6
COPCO 2 (1 & 2)	Must Run	16.8
Covanta Marion	Must Run	8.4
Cowiche Hydroelectric Project	Must Run	1.0
Coyote Springs 1	East 1	204.1
Coyote Springs 2	East 1	218.2
Danskin (Evander Andrews) CT1	West 4	144.6
Danskin group	East 7	78.2
Danskin group	East 7	78.2
Dietrich Drop	Must Run	1.0
Don Plant (Simplot Pocatello)	Must Run	5.9
Dry Creek	Must Run	1.8
Dry Creek Landfill	Must Run	2.9
Elkhorn Valley	Must Run	30.0
Encogen 1-4	Must Run	134.3
Everett Cogeneration Project	Must Run	21.9
Evergreen Forest Products (Tamarack)	Must Run	4.2
Fall Creek 1 - 3	Must Run	1.0
Fall River	Must Run	3.1
Falls Creek	Must Run	2.1
Farmers Irr. Dist. No. 2 (Copper Dam)	Must Run	1.0
Farmers Irr. Dist. No. 3 (Peters Drive)	Must Run	0.9
Foote Creek I	Must Run	14.9
Foote Creek II	Must Run	0.6
Foote Creek IV	Must Run	6.1
Fossil Gulch	Must Run	2.9
Frederickson 1	West 4	76.9
Frederickson 2	West 4	76.9
Frederickson Power 1	West 1	225.7
Fredonia 1	West 4	107.1
Fredonia 2	West 4	107.1
Fredonia 3	West 3	52.7
Fredonia 4	West 3	51.8
Freres Lumber	Must Run	8.4
Georgia-Pacific (Camas)	Must Run	43.7
Georgia-Pacific (Wauna)	Must Run	22.7

Glenns Ferry Cogeneration	Must Run	8.3
Goldendale CC 1A & 1B	East 1	204.9
Goodnoe Hills	Must Run	28.2
Grays Harbor Energy Facility (Satsop)	West 1	545.4
H.W. Hill (Roosevelt Biogas) 1 - 5	Must Run	9.6
Hampton Lumber	Must Run	6.1
Hay Canyon	Must Run	30.3
Hazelton A	Must Run	1.0
Hazelton B	Must Run	1.5
Hermiston Generating Project CC1A & 1B	East 2	195.0
Hermiston Generating Project CC2A & 2B	East 2	195.0
Hermiston Power Project	East 3	438.0
Hidden Hollow	Must Run	1.5
Hopkins Ridge	Must Run	47.0
Hoquiam Diesels	Ignore	9.2
Horseshoe Bend	Must Run	3.6
Horseshoe Bend Hydroelectric	Must Run	3.1
Ingram Warm Springs Ranch B	Must Run	0.6
Iron Gate	Must Run	9.4
Jim Bridger 1	Bridger	447.1
Jim Bridger 2	Bridger	447.1
Jim Bridger 3	Bridger	447.1
Jim Bridger 4	Bridger	447.1
John H. Koyle (Koyle Ranch Hydroelectric) 1-3	Must Run	0.5
Judith Gap	Must Run	16.1
Kettle Falls Generating Station	Must Run	44.6
Kettle Falls GT	Must Run	6.0
Klamath Cogeneration Project	East 1	396.6
Klamath Generation Peakers 1 & 2	East 5	42.5
Klamath Generation Peakers 3 & 4	East 5	42.5
Klondike I	Must Run	7.2
Klondike II	Must Run	22.5
Klondike III	Must Run	37.6
Koma Kulshan	Must Run	3.6
Lancaster (Rathdrum CC)	East 1	232.2
Lateral No. 10	Must Run	0.5
Leaning Juniper	Must Run	30.2
Little Wood River Ranch	Must Run	0.5
Lower Low Line No. 2	Must Run	1.4
LQ-LS Drains	Must Run	0.9
Magic Dam	Must Run	1.6
March Point 1 - 4	Must Run	117.5
Marengo I	Must Run	42.2
Marengo II	Must Run	21.1
Meyers Falls	Must Run	0.5
Middle Fork Irrigation District 1	Must Run	0.3
Middle Fork Irrigation District 2	Must Run	0.3
Middle Fork Irrigation District 3	Must Run	1.0
Mile 28 (1 & 2)	Must Run	0.5
Mink Creek	Must Run	0.5
Mint Farm	West 1	267.7
Mirror Lake (Hutchinson Creek)	Must Run	0.5

Montana One (Colstrip Energy)	Colstrip 1&2	11.8
Mora Canal Drop	Must Run	0.9
Morrow Power	East 6	21.3
N-32 (Northside Canal)	Must Run	0.3
Nine Canyon	Must Run	28.8
North Valmy 1	Valmy	116.2
North Valmy 2	Valmy	122.6
Northeast 1	East 8	5.4
Northeast 2	East 8	5.4
Olympic View 1 & 2	West 3	4.9
Opal Springs	Must Run	1.6
Owyhee Dam	Must Run	0.5
Owyhee Tunnel No. 1	Must Run	3.5
Plummer Forest Products	Must Run	5.3
Port Westward CC1A & 1B	West 1	357.5
Portneuf River	Must Run	0.5
Potlatch (Lewiston) 1 - 4	Must Run	63.1
Raft River I	Must Run	12.2
Rathdrum 1	West 4	74.8
Rathdrum 2	West 4	74.8
River Road Generating Plant	West 1	208.1
Rock Creek #1	Must Run	0.5
Rock Creek #2	Must Run	0.5
Rock River I	Must Run	18.0
Ross Creek	Must Run	0.1
Rough & Ready Lumber	Must Run	1.0
Rupert Cogeneration	Must Run	8.3
Savage Rapids Diversion	Must Run	0.6
Short Mountain group	Must Run	2.3
Shoshone/Shoshone II	Must Run	0.5
Sierra Pacific (Aberdeen)	Must Run	8.5
Sierra Pacific (Fredonia)	Must Run	2.6
Skookumchuck	Must Run	1.8
Slate Creek	Must Run	2.2
South Dry Creek	Must Run	0.3
St. Anthony	Must Run	0.3
Stateline	Must Run	90.1
Sumas Cogeneration Station	Must Run	103.2
Tenaska Washington Partners Cogeneration Station	West 2	205.6
Tiber-Montana	Must Run	0.9
Tieton	Must Run	7.1
Tuttle Ranch (Ravenscroft)	Must Run	0.6
Twin Falls (TFHA)	Must Run	3.1
Twin Reservoirs	Must Run	0.5
Upriver	Must Run	4.3
Vaagen Brothers Lumber	Must Run	2.5
Vansycle Wind Energy Project	Must Run	7.5
Wapato Drop 2 (#1)	Must Run	1.5
Wapato Drop 3 (#1 - 2)	Must Run	1.0
Weyerhaeuser (Springfield) 4 (WEYCO)	Must Run	21.0
Wheat Field	Must Run	29.0
Wheelabrator Spokane	Must Run	19.3

White Creek	Must Run	60.5
Whitehorn Generating Station 2	West 4	76.9
Whitehorn Generating Station 3	West 4	76.9
Wild Horse Wind	Must Run	68.6
Wilson Lake	Must Run	1.5
Wolverine Creek	Must Run	18.1
Yellowstone Energy (BGI)	Must Run	15.8

source: ...\Plan 6\Studies\Data Development\Resources\Existing Non-Hydro\091018 Database system**Explorer_100228_225825.xls**, worksheet "Unit Comparisons"

Many of the units, it may be noted, are in the "must run" category. The reasons for this assignment depend on the particular plant. Some units are combined heat and power (CHP) installations owned by customers. Wind, geothermal, and most other renewables belong to his family because they have virtually zero variable operating cost. Run of River Hydro, which is generally not dispatchable, and the Columbia Station nuclear power plant, which has very low operating cost, also belong to this category.

THE UNFORESEEABLE

Technological innovation can rewrite the economic rules of generating power. Legislative and regulatory initiatives can have and have had this effect. How does the Council's RPM model deal with such "game changers?"

While the events are impossible to forecast, their effects on power system cost are foreseeable. Studies can thereby discover situations that deserve attention.

For example, consider the possibility of a breakthrough that makes solar photovoltaic generation cost effective for individual homeowners. If a large number of homeowners installed these systems, it is reasonable to expect load requirements would decline. The utilities themselves would likely find a way to harness the technology in larger quantities and at even lower cost. Surplus utility generation would drive down wholesale power prices. Could it impact natural gas prices? Possibly. It is difficult to imagine, on the other hand, how this breakthrough would affect hydrogenation or power plant forced outages.

In this manner, a solar photovoltaic breakthrough is interpreted in terms of the sources of uncertainty the Council's model already addresses. Then how do these unforeseeable events change the standard representation of the uncertainties?

Innovations with unknown likelihood change the scale of and relationship among uncertainties. Council studies reflect a larger scale of uncertainty than intuition might first suggest. This simply reflects the potential for a larger pool of contributing factors than history provides. Using alternative correlations among uncertainties allows for the possibility that market structures will change, regulations will evolve, and technology will transform.

Combining futures in unlikely ways, moreover, reveals how alternative sources of uncertainty can conspire to bring extraordinary risk. The coincidence of several "unlikely" forces has been responsible for catastrophic events in very recent history, such as the subprime mortgage debacle.

Once revealed, however, it is still incumbent on the Council to decide whether a particular combination of events is meaningful. Modeling is a powerful tool for ferreting out sources of risk. Judgment and experience, however, are the ultimate measures of risk and of any plan's merit in meeting risk.