The Portfolio Model

Introduction

The portfolio model is a simple Excel worksheet that calculates energy and costs associated with meeting regional requirements for electricity. The energy and costs are for a single plan under a specific future.[1] As described in Chapter 6, estimating costs for a plan under many futures is necessary in order to obtain a likelihood distribution for cost. Preparing the feasibility space and efficient frontier, in turn, require the evaluation of many plans. Part of the objective of this appendix is to explain how the portfolio model works within other applications to achieve the goal of creating the feasibility space.

This appendix begins with a description of portfolio model principles. A flow diagram of the overall modeling process orients the reader to where the portfolio model fits into the process. The flow diagram shows that *period-specific* calculations are the lowest-level and simplest calculations in the workbook, providing a starting place for the detailed description of the model. (See "Single Period," beginning on page L-11.) The *period-specific* section also outlines the model's approach to calculating costs. Certain aspects of uncertainty and portfolio element behavior require a consideration of what is happening over time and how events in one period affect those in subsequent periods. In the section "Multiple Periods" on page L-58, the appendix discusses the inter-period nature of correlations and behaviors. This section also addresses the operation of smelters, the construction of new resources, and other activities that rely on events over multiple periods.

It is important to note that a portion of the description of the portfolio model is in Appendix P, instead of here in Appendix L. The treatment of uncertainties, like load and hydro generation, are to some extent separable from the rest of the model. (This appendix identifies a particular range of the model worksheet that creates the futures later in this introduction, on page L-10.) Because the description of uncertainties appears in Appendix P, it makes sense to describe the regional model's treatment of those uncertainties in the same place. This appendix provides additional explanation wherever the uncertainties bear on the aspects of the model discussed here.

The section "Resource Implementation and Data," beginning on page L-92, presents the rationale and references for most of the model's data. The section identifies key parameters for existing and candidate generation resources, system benefit charge (SBC) wind additions, and contract imports and exports. It also discusses the characteristics and treatment of independent power producers (IPPs).

[1] Chapter 6 defines the terms "plan," "future," and "scenario" and provides examples. The glossary of this appendix includes brief definitions.

The appendix next describes the Council's modeling efforts. It illustrates how the Crystal Ball® Monte Carlo games are prepared and how the OptQuest™ stochastic optimization application is configured. The appendix lists some special utilities that extract data, prepare reports, and assist users to verify calculations. It summarizes the insights the Council has obtained through application of these tools and provides, in particular, an explanation of the value of conservation under uncertainty, which deterministic models fail to capture.

The appendix concludes with an introduction to ***Olivia***, the meta-model that created the regional portfolio model. ***Olivia*** creates Crystal Ball-aware Excel workbooks ready for use under Crystal Ball and OptQuest or for stand-alone use. ***Olivia*** is available free to any individual or agency that wants to create a portfolio or risk model describing their unique situation.

The reader may want to consult the following Table of Contents for orientation to the remaining appendix.

Table of Contents

Principles

The portfolio model is a simple calculation engine. For a given plan, it estimates costs of generation, of wholesale power purchases and sales, and of capacity expansion over the 20-year study under a particular future. An Excel add-in, Decisioneering Inc.'s Crystal Ball, runs a Monte Carlo simulation, with each game corresponding to a future, compelling the portfolio model to recalculate for each future. The portfolio model takes each future and determines the energies and costs associated with that future. A second Excel add-in finds least-cost, risk constrained plans using stochastic, non-linear optimization techniques.

Figure L-1 illustrates the kind of calculation that the portfolio model makes in a specific scenario. It shows energy use resulting from a plan over a two-year period for the fixed future. A future defines the hydro generation, loads, gas prices, and so forth in each hour. Existing and future resources in the plan generate power, largely in response to wholesale electricity prices. Because generation rarely exactly matches load, a load serving entity must buy power from the wholesale market or sell into the wholesale market. The costs and revenues in each hour add to any future fixed costs for existing and new generation or capital costs for new generation and conservation. The model discounts these cash flows to the beginning of the study. Of course, the portfolio model does this for 20 years, not for two years, but the process is identical.

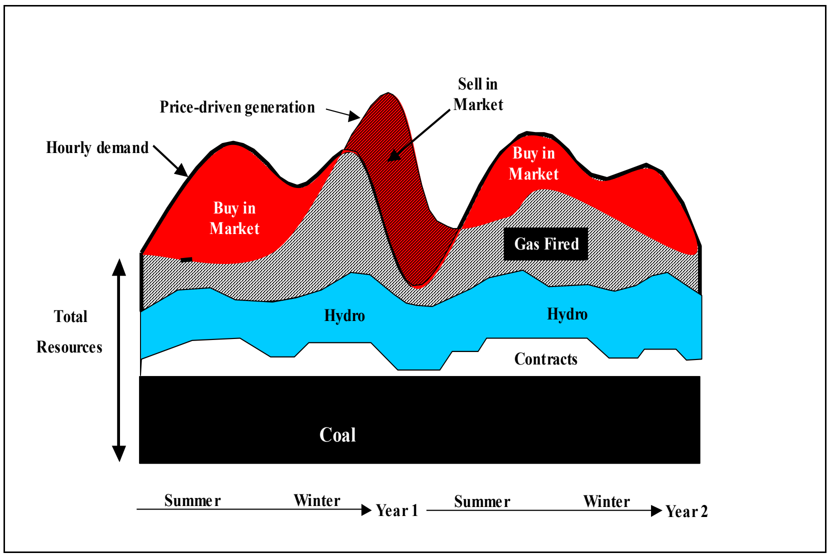

Figure L-1: Portfolio Model Calculation

The model evaluates 750 futures for each plan and about 1,400 plans per study, for a total of around a million scenarios. An hourly calculation for each of these 20-year scenarios would be prohibitive.[2] For this reason, the model uses special algorithms to estimate plant capacity factors, generation, and costs for periods of three months. The 20-year study period is represented by 80 hydro-year quarters on peak and another 80 off peak. The model does not break the Northwest into sub-regions. Consequently, there is no explicit treatment of cross-Cascade and other intra-regional transmission constraints. The model, however, does constrain imports and exports to 6,000 megawatt-quarters, before any contracts.[3] Transmission constraints within the region are considered outside the model. Existing regional thermal resources

[2] One estimate using AURORA® run times put the study at a little over 85 years.
[3] Contracts may be fully counter-scheduled.

are aggregated down to about 30 plants with similar characteristics. A 50-year streamflow record and 2000 Biological Opinion (BiOp) constraints on operations determine possible hydro generation. Operation of the region's seven remaining smelters depends the relative price of aluminum and wholesale electricity.

One of the things that make the portfolio models particularly simple is its construction in an Excel worksheet. Most analysts know how to read and modify an Excel worksheet. Columns in the worksheet denote periods, and rows contain information about loads and resources. Although simple to interpret, however, there are many calculations in the regional portfolio worksheet. In addition, special purpose Excel functions perform much of work, and the model carefully controls calculation order within worksheets. These issues require explanation.

To help the reader understand how the model works, therefore, its description will proceed in two steps. The first step will describe calculations that pertained to a single period. These include, for example, estimating thermal generation and costs for a given period. They will also cover some simple resources, such as contracts and hydrogeneration defined by streamflow. Balancing load requirements and generation with electricity price adjustments is another process that takes place within a single period. The second step will describe calculations involving several periods. This includes price processes, and the description of underlying trends for natural gas price and loads. This also includes more complex load and resource behaviors, such as decisions to shut down or restart a smelter and the rules for adding new resources to the system, such as those that govern whether or not to proceed with the construction of power generation resources.

ICON KEY
🗁 Key idea
◆ Definition

This appendix provides several tools to help the reader track this discussion. The first tool is the use of icons to flag key definitions and concepts. A table of these icons appears that the left. The second tool is a workbook, L24DW02-f06-P.xls, containing a pre-draft plan version the regional portfolio model. The reader can request a copy of the workbook from the Council or download a copy of this workbook from the Council's web site (http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/L24X-DW02-P.zip). References to the workbook L24DW02-f06-P.xls appear in curly brackets ("{}"). Understanding the description does not require reference to the workbook, however. References to Council data sources appear in square brackets ("[]"). The References section at the end of the appendix lists these sources. Publicly available sources appear in footnotes.

To motivate the description of the portfolio model that appears here, discussion next turns to the logic structure of the portfolio model. The model calculation follows a specific order, with columns within certain ranges calculated in order. The strict order of calculation reflects the passage of time and the cause and effect of prior periods on subsequent periods. It also suggests why some calculations are best understood in terms of behaviors within a single period and others require understanding processes that span multiple periods.

Logic Structure

When a user opens the portfolio model workbook, the values they see are values for a particular future and for a particular plan. It is within this future (or game) that the energy and cost calculations take place. How, then, are the futures changed to create a cost distribution for a plan and the plans changed to create the feasibility space?

Figure L-2 illustrates the overall logic structure for the modeling process. The optimization application, the OptQuest Excel add-in, controls the outer-most loop. The goal of the outer-most loop is to determine the least-cost plan for each level of risk. It does so by starting with an arbitrary plan, determining its cost and risk, and refining the plan until refinements no longer yield improvements. The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with equal (or lower) risk but lower cost. The process ends when we have found a least-cost plan for each level of risk. This process is a form of non-linear stochastic optimization. The interested reader can find a more complete, mathematical description of the optimization logic in reference [**1**].

In terms of the worksheet model, the optimizer OptQuest controls the Crystal Ball Excel add-in. OptQuest hands a plan to Crystal Ball, which manifests the plan by setting the values of "decision cells[4]" in the worksheet. These are the yellow cells in {range R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop, labeled "Monte Carlo Simulation," in Figure L-2. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest. For each future, Crystal Ball assigns random values[5] to 1045 "assumption cells." These assumption cells appear as dark green cells throughout the worksheet. (See for example, {R24}.) Crystal Ball then recalculates the workbook. In the portfolio model, however, automatic recalculation is undesirable, as described on page L-9. The portfolio model therefore substitutes its own calculation scheme. It uses a special Crystal Ball feature that permits users to insert their own macros into the simulation cycle, as shown in Figure L-3. Before Crystal Ball gets results from the worksheet, a macro recalculates energy and cost, period by period, in the strict order illustrated in Figure L-4 and described on page L-9. The values in the Crystal Ball "forecast cells" then contain final net present value (NPV) costs that Crystal Ball saves until the end of the simulation. Forecast cells are those that have the simulation results and have a bright blue color. The NPV cost, for example, is in {CV1045}.

[4] "Decision cell," "assumption cell," and "forecast cell" are Crystal Ball terms. The glossary at the end of this appendix defines each. This appendix details the function and application of decision cells in the section "Parameters Describing the Plan," page L-72. Appendix P describes "assumption cells."
[5] For a number of good reasons, these values are not truly random in the everyday sense of the word. For example, the random number generator uses a seed value, so that an analyst can reproduce each future exactly for subsequent study. The generator also selects the values to provide a more representative sampling of the underlying distribution, a technique known as Latin Hyper Square or Latin Hyper Cube.

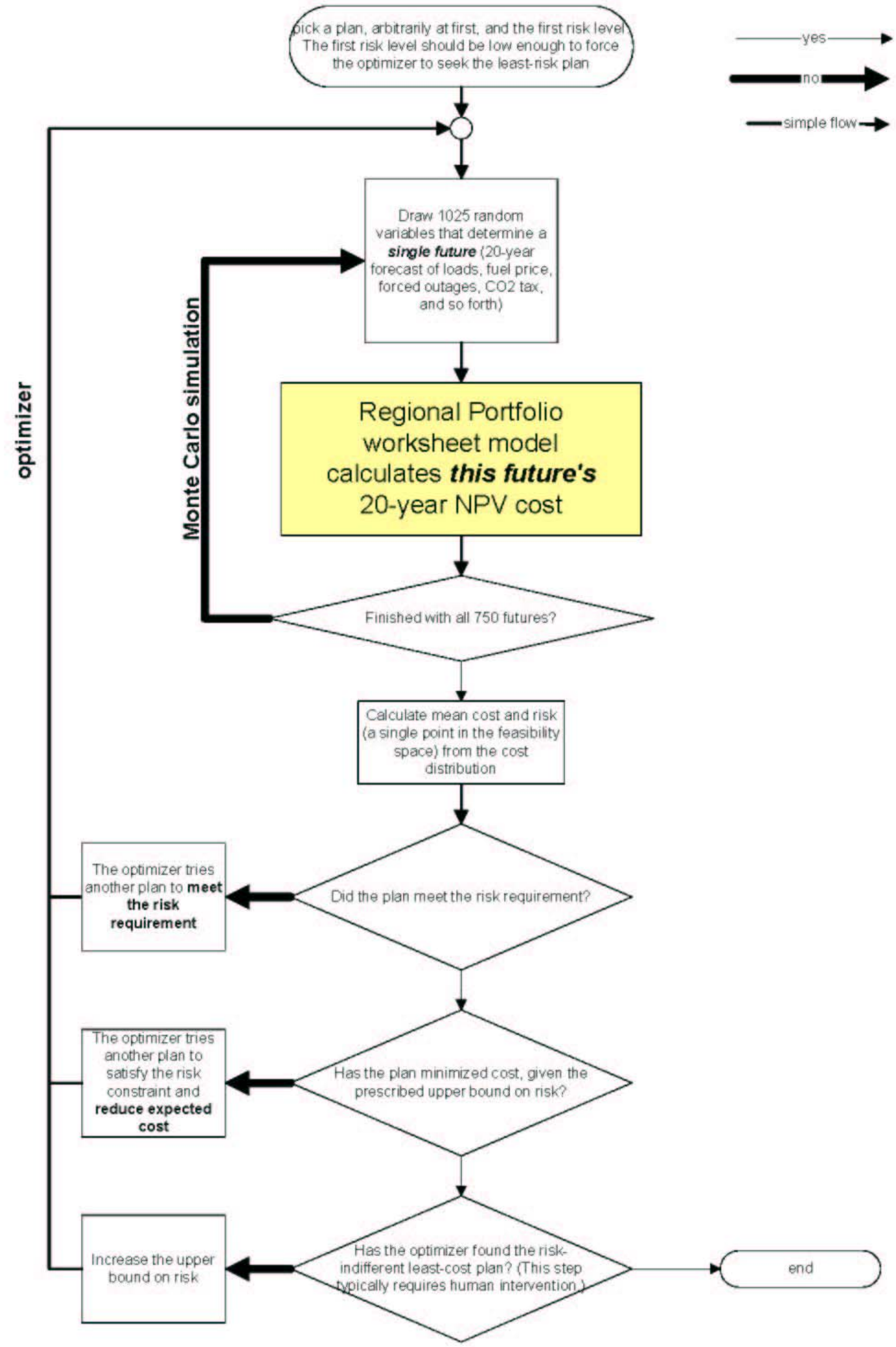

Figure L-2: Logic Flow for Overall Risk Modeling

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the last macro in Figure L-3 fires. This macro calculates the custom risk measures and updates their forecast cells. The custom risk measures include, for example, TailVaR_{90}, CVaR_{20000}, VaR_{90}, and the 90th Quintile.

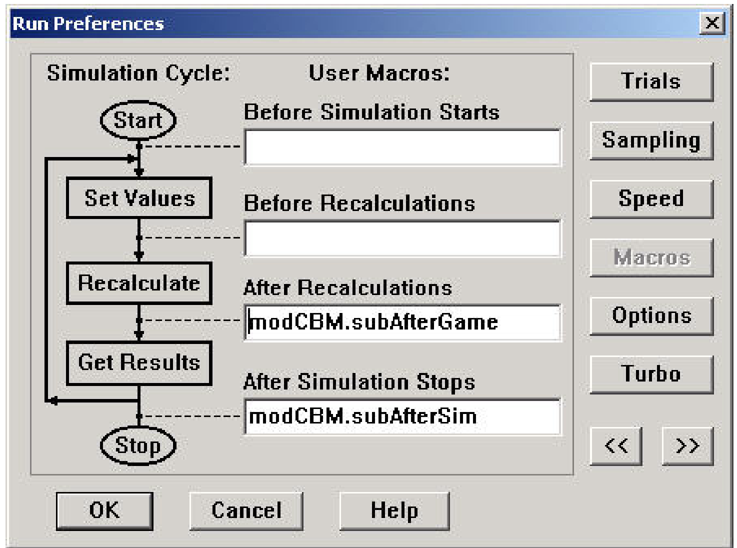

Figure L-3: Crystal Balls Macro Loop

One of the capabilities of Crystal Ball is distributed computation. Under its "Turbo Mode," Crystal Ball on a "master" machine packages bundles of several games and sends a bundle to each "worker" machine in a network, as illustrated in Figure L-5. After the bundle of games is complete, the worker sends back the results and requests another bundle. When all the games are finished, Crystal Ball evaluates the simulation results and returns required data to OptQuest. The Council uses nine 3-GHz Pentium 3 "worker" machines in a dedicated network, together with a 3-GHz Pentium 3 "master" and a server that coordinates the flow of bundles.

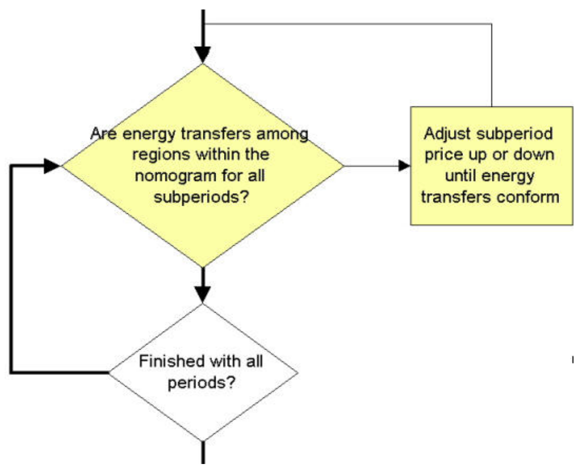

Figure L-4: Logic in the Regional Portfolio Worksheet Model

The portfolio model performs the duties of the innermost task, identified by the shaded box in Figure L-2. Given the values of random variables in assumption cells, the portfolio model constructs the futures, such as paths and jumps for load and gas price, forced outages for power plants, and aluminum prices over the 20-year study period. It does this only once per game. It then balances energy for each period, on- and off-peak and among areas, by adjusting the electricity price. The regional portfolio model uses only two areas, however, the region and the "rest of the interconnected system." Only after it iterates to a feasible solution for electricity price in one period does the calculation moves on to the next period. After calculating price, energy, and cost for each period, the model then determines the NPV cost of each portfolio element and sums those to obtain the system NPV. This sum is in a forecast cell.

There is a special step in the above process to recalculate the cells that control the long-term interaction of futures, prices, and resources, referred to here as the "Twilight Zone." This portion of the worksheet contains, for example, formulas for price elasticity of load and decision criteria. The workbook recalculates this portion of the worksheet multiple times for each subperiod.

Excel workbooks use an internal "recalculation tree" to determine which cells need recalculation when the user modifies any Excel worksheet.[6] If the workbook containing this worksheet is in automatic recalculation mode, the change will trigger a search of the tree, and Excel recalculates only the affected cells. This usually saves a great deal of time. It also explains why an Excel workbook initially may require 30 seconds to calculate when loaded but only an instant when a user makes certain changes.

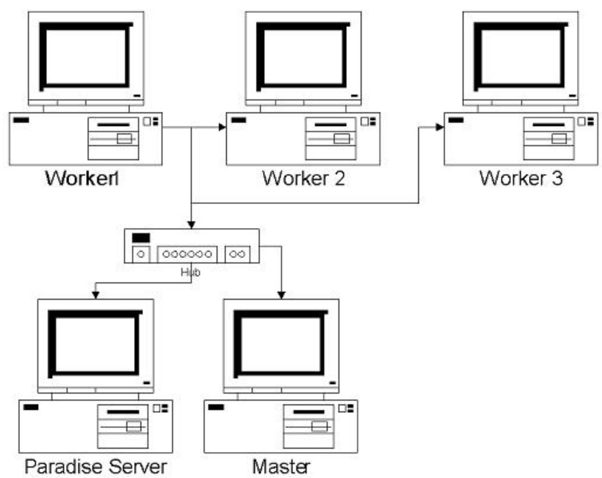

Figure L-5: Distributed Processing

The portfolio model worksheet, however, must solve several energy balancing problems by iteration, illustrated in Figure L-4. (The details of this process are in the section "RRP algorithm," which begins on page L-51.) This process proceeds from the earliest period (far left column {column R}) to the last period (far right column {column CS}). Under automatic calculation, the cells involved in iterative recalculation would not only influence a large number of "down stream" calculations but would cause dependent user-defined functions to fire, as well. These down stream recalculations could take significant amounts of time. Moreover, the energy rebalancing calculation finally discards the values of the down-stream cells, because the workbook must eventually recalculate those values anew. For this reason, the model turns off automatic calculation. The model instead controls the recalculation of all cells with a VBA range recalculation.

Figure L-6 illustrates the calculation order described above. The number in the parentheses is the order. The plus sign (+) is a reminder that iterative calculations take place in the area. Calculations made only once per game are near the top of the worksheet {rows 26-201}. The illustration denotes those recalculations that must be made multiple times per subperiod by TLZ {rows 202-321}. NP stands for on-peak

[6] The reader can find a description of the Excel recalculation method at http://msdn.microsoft.com/library/default.asp?url=/library/en-us/dnexcl2k2/html/odc_xlrecalc.asp

{rows 318-682}; FP stands for off-peak {rows 684-1058}. The area at the far right refers to the NPV summary calculations {range CU318:CV1045}.

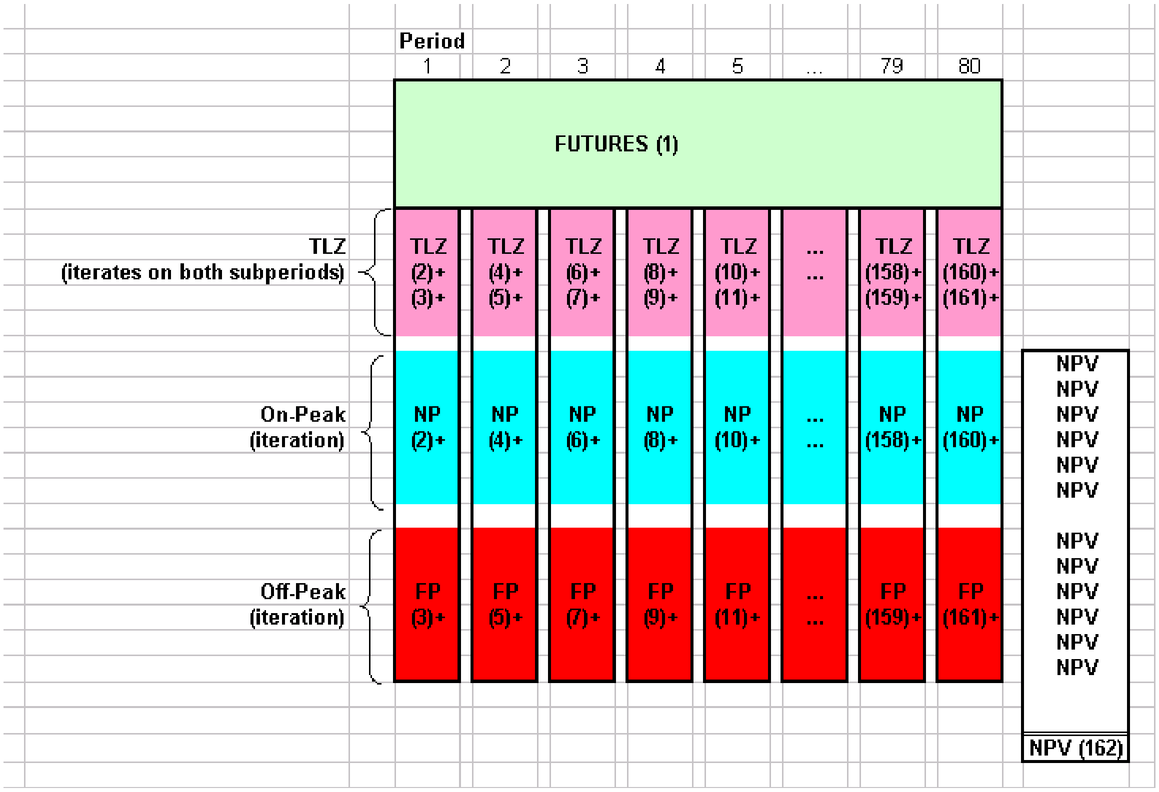

Figure L-6: Portfolio Model Calculation Order

Appendix P documents the uncertainties in the regional portfolio model. This includes the worksheet formulas for describing the uncertainties. Because it would be redundant to cover the same material in this appendix, the scope of this appendix is everything *except* the uncertainties.

Figure L-6 permits us to state the scope of this appendix with respect to ranges within of the portfolio model. Appendix P describes the calculations in the area of the worksheet denoted by "FUTURES (1)". This Appendix L discusses all remaining areas.

With this overview, this appendix starts the detailed description of the regional model with perhaps the simplest area of calculation in the workbook, the single period. The calculations within a single period are to a certain extent independent of each other. They are the building blocks for more involved behaviors that span multiple periods. They also are the province of rich behavior and some of the most novel algorithms.

Single Period

This section considers only a single period in the study timeframe, December 1, 2009, through February 28, 2010 {column AQ}. There is nothing special about this period; any other period would do. Logic is identical across periods.

The portfolio model aggregates time into periods. The primary purpose for this is to achieve efficiencies in calculating energy generation and costs. Annual periods do not capture interesting seasonal behavior, and using monthly calculations do not provide any benefit over quarterly calculations. Because hydrogeneration determines much of the resource behavior in the Pacific Northwest, the model uses hydro quarters. For the purposes of the portfolio model, the hydro-year begins September 1, so the quarters are September through November, December through February, March through May, and June through August. This appendix will occasionally refer to these as the autumn, winter, spring, and summer quarters.

One of the distinctive features of the portfolio model is how it defines periods in terms of hours. A **standard month** is exactly four weeks. Similarly, a **standard quarter** is three standard months, and a **standard year** is four standard quarters. A standard month has exactly four weeks. By adopting this convention the number of hours on peak[7] and off peak in each month, quarter[8], and year are fixed and uniform. Consequently, conversion calculations to MWh from average megawatts are the same across all periods. In addition, shifting patterns of holidays and Sundays from month to month and year to year do not create misleading results due only to that kind of variation.

Because the periods in the portfolio are rather long, the ratio of on and off-peak hours using standard quarters are close to those the model would have obtained had the model not used standard quarters. Consequently, the regional portfolio model keeps costs in standard time units and simply scales up the results in the net present value calculation. For example, see {row 323, column CV}, where the model ratios up the costs by the ratio of hours in a non-leap year to the hours in a standard year, 8760/8064, or about 8.63 percent.

This convention does introduce one source of additional complexity, however. It requires that the model handle fixed costs carefully. Resource economics, and economic resource selection in particular, depends on the relationship between fixed and variable costs. Fixed costs are often denominated in units such as dollars per kilowatt-year ($/kWyr). The regional portfolio model uses dollars per kilowatt-standard year ($/kWstdyr), which is smaller by about 7.95 percent (1-8064/8760). If an analyst wished to scale fixed costs by the number of hour in a particular month and year, however, any fixed costs would scale appropriately. The detailed explanation of fixed costs under this convention appears on page L-69, where this appendix deals with "New Resources, Capital Costs."

[7] The portfolio model assumes a 6x16 convention for on-peak hours. That is, on peak is defined as hours 7 through 22 (6 AM to 10 PM) each weekday and Saturday. The remaining hours are off-peak.
[8] There are 1152 on-peak hours (6x16x4x3) each quarter and 864 off-peak hours.

Table L-1: Plan DW02

Conservation: $10/MWh higher on the supply curve in all periods, for both non-lost opportunity and discretionary conservation.[9]
Earliest construction start dates for the following increments of resource:
CCCT: 610 MW in 12/2009
SCCT: 100 MW in 12/2019,
Wind Power Plants: 1200MW in 12/2009, 1300MW in 12/2015, 2000MW in 12/2017, 400MW in 12/2019
Coal-Fired Power Plants: 400 MW in 12/2009
Demand Response: 500MW in 12/2007, 250MW in 12/2009, 250MW in 12/2011, 250MW in 12/2013, 250MW in 12/2015, 250MW in 12/2017, and 250MW in 12/2019
Critical Water threshold for resource additions: 3000 MWa

If an analyst needed to know the energy and costs associated with a particular calendar month and year, using standard months, quarters, and years makes recovering this information easy. The model effectively determines costs by normalizing energy and cost to rates of energy per hour (power in MW) and costs per hour ($/MWh and $/kWh), and then multiplying by the fixed number of hours in each standard subperiod.

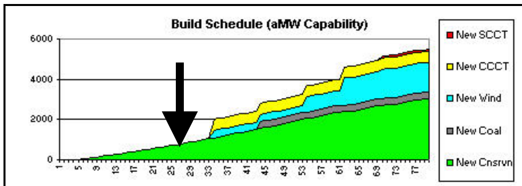

Figure L-7: Build 0ut of Future 6

Recovering a month and year's actual energy and cost amounts to rescaling by the month and year's actual hours per each subperiod. If the user wished to, the portfolio model could rescale before discounting of costs in the total system cost calculation.

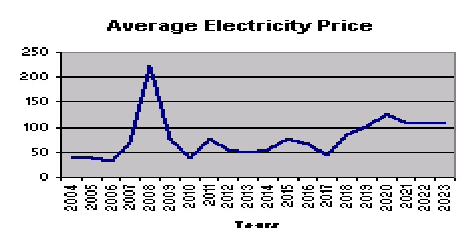

Figure L-8: Electricity Price Future

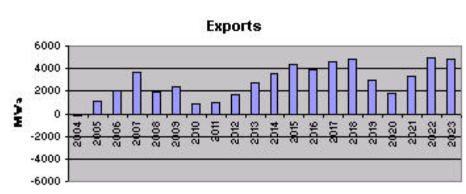

Figure L-9: Exports

[9] The description of this element in the decision criterion for conservation appears in Chapter 6 and under the section "Decision Criteria" that appears later in this appendix.

In addition to specifying the period that serves as our example, this description will assume a specific plan under a specific future.[10] Working with specific choices should make the calculations more concrete and easy to follow. The plan appears in Table L-1. The behavior of this plan under the 750 futures is illustrated in the workbook L24X-DW02-P.xls. The behavior of this plan under future number six appears in Figure L-7 and the details are in L24DW02-f06-P.xls. The figure contains an arrow that identifies the period under consideration. This plan is not the Council's recommended plan but illustrates some interesting behavior for the reader. Figure L-8 through Figure L-12 show other aspects of future six and the behavior of this plan under future six.

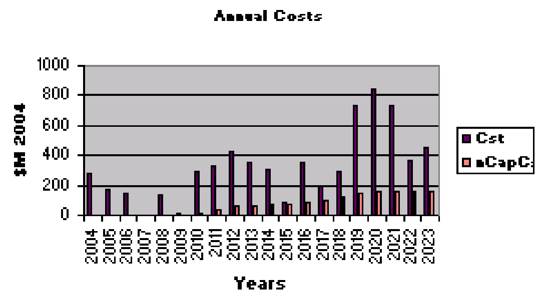

Figure L-10: Total Annual Costs and Capital Costs Only

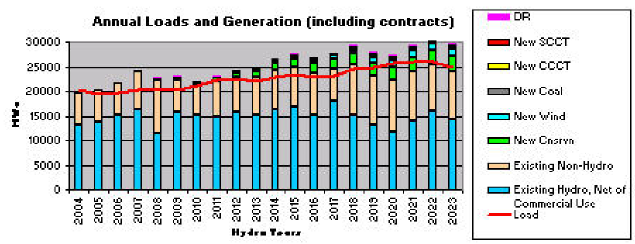

Figure L-12: Annual Energy Generation and Load

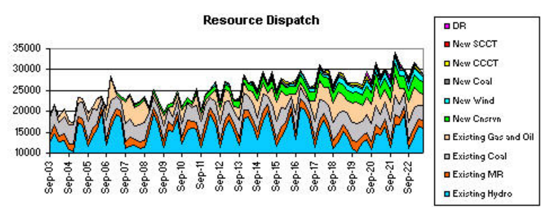

Figure L-11: Quarterly Energy Generation

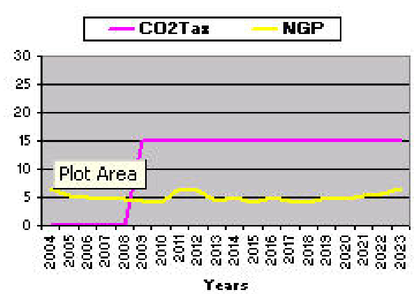

Figure L-13: Natural Gas Price and CO_2 penalty

The portfolio model NPV cost includes both variable and fixed components of system cost. The variable component includes total fuel, variable O&M, spot market purchases and sales, and the value of purchase contracts in the electricity market. (See the section "Contracts" for a more detailed discussion of contract costing.) The fixed component includes conservation costs and new plant incremental fixed O&M and construction cost.[11] The portfolio model uses special treatments of fixed and variable costs. The following section addresses the treatment of variable costs in the model; the subsequent section discusses fixed costs.

Valuation Costing

The portfolio model estimates period variable costs, such as hourly market purchases of electricity for a month, from average values over the period. Period costs can be tricky to estimate, however, because of the intra-period correlations that exist between relevant variables, such as market price for electricity and hourly requirements. For example, consider two simplified systems, System A and System B, which face the same market price over some period, say a week. (See Figure L-14.) The

[10] Chapter 6 provides definitions for the terms "future," "plan," and "scenario."

[11] Because the regional version of the portfolio model does not perform economic retirement, the model considers the incremental fixed O&M of existing plants sunk and does not include it.

task is to calculate the cost of market purchases. Even if both systems have average zero net position (resources-loads), they can have a non-zero cost. Not only this, but depending on the hourly correlation of their position with market price, the cost may be negative or positive. Clearly then, a calculation using average prices and positions is misleading. A simple illustration will demonstrate how this arises.

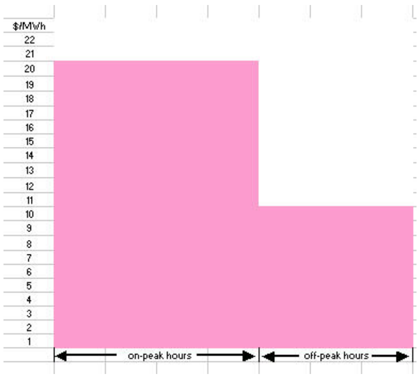

Figure L-14: Prices over on- and off-peak hours

The market price consists of a constant on-peak price of $20/MWh and a constant off-peak price of $10/MWh, as illustrated in Figure L-14. Although the on- and off-peak periods would alternate daily, the illustration aggregates the corresponding hours to simplify the calculation. The on-peak hours are 4/7 of the total number of hours. System A has loads -- constant over the subperiods -- shown as the heavy line in Figure L-15. The load is 2000 MW on peak and 1300 MW off peak, averaging 1700 MW over the week. System A has a constant, flat existing resource of 1700 MW, which results in a deficit on peak and a surplus off peak. The level of the source is shown by the cross-hatched area in Figure L-15. A simple calculation shows the net cost of market purchases over the week is $119,000.

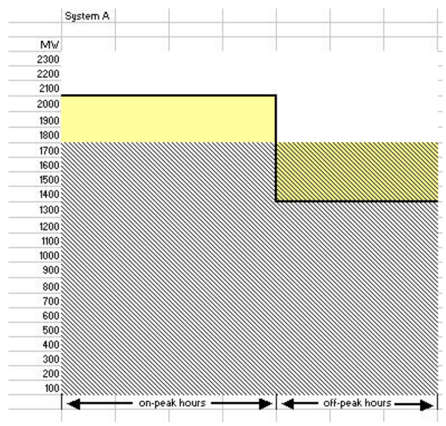

Figure L-15: System A

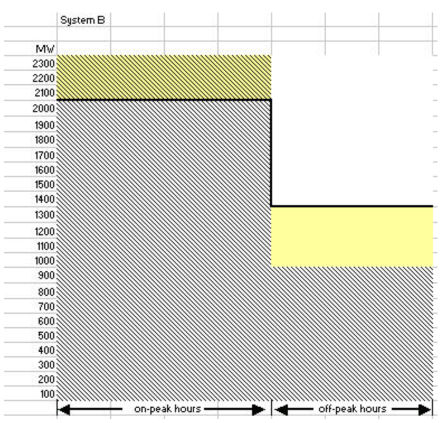

Figure L-16: System B

The System B has hydro generation (the cross-hatch area in Figure L-16) that is equal to loads on average, but surplus to its needs on peak. Again, using averages across the week, the cost of market purchases would be zero. System B, however, has 2300 MW on peak hydro generation and 900 MW off peak. Now the position has the opposite correlation to market price. The net cost of market purchases over the week is now negative, that is, there is a net $119,000 net benefit selling power into the market over the week.

To make these results more general, the expected revenue given average price, average position, and their correlation is

$$E(pq) = E(p)E(q) + \sigma_p \sigma_q \rho_{pq} \qquad (1)$$

where ***p*** denotes hourly price, ***q*** represents hourly position, ***E(pq)*** is expected revenue, ***E(q)*** is average position, ***E(p)*** is average price, $\boldsymbol{\sigma_p}$ is the standard deviation of price, $\boldsymbol{\sigma_q}$ is the standard deviation of position, and $\boldsymbol{\rho_{pq}}$ is the correlation between price and position. This is an estimate of revenue that the portfolio model uses is several calculations.

The more general situation, of course, is more challenging. Costs and revenues for power plants potentially include a complicated and time-varying set of correlations. For example, a gas-fired power plant revenue involves not only correlation of production to electricity prices, but of production to gas prices, and of gas prices to electricity. This situation would exist for each resource. Fortunately, there is a computational short cut available.

Instead of calculating costs using all the various cross-correlations, there is an easier calculation that involves only comparisons to the electricity market. To see this, we start with a "rate base" cost calculation:

$$c = \sum_i q_i p_i + p_m (Q - \sum_i q_i) \qquad (2)$$

c is total cost ($)

q_i is quantity (MWh) provided by resource i

p_i is the price ($/MWh) of resource i

p_m is the price ($/MWh) for wholesale energy

Q is total requirement

In this calculation, the variables represent hourly values. This calculation sums up the operating costs for each of the generating units and adds to that sum the cost of meeting the remaining load in the market. The problem is that $\boldsymbol{p_m}$ and $\boldsymbol{(Q-\Sigma q_i)}$ are correlated within a period, but the correlation is complex. Estimating $\boldsymbol{\Sigma q_i}$ alone involves knowledge of how the production among resources are correlated. Moreover, the relationship between the load Q and Σq_i must be calculated. By rearranging terms, however, another calculation for costs emerges.

$$
\begin{aligned}
c &= \sum_i q_i p_i + p_m (Q - \sum_i q_i) \\
&= p_m Q - p_m \sum_i q_i + \sum_i q_i * p_i \\
&= p_m Q - \sum_i q_i (p_m - p_i)
\end{aligned}
$$

This is the “valuation” cost estimate. The name stems from the fact that the load and each resource are valued in the electricity market. The first term in the last equation is the cost of meeting total load in the market. The second term is the sum of the resource values in the market.

The valuation formula simplifies the cost calculation, because we only have to consider how each resource’s cost and dispatch relate to market price, rather than to other resources. For example, wind generation, conservation, and many other resources do not dispatch to market price. This mean their correlations to electric market price are zero, and multiplying average period energy by average electricity price yields expected revenues. Thermal generation, however, is a more complex situation. Thermal plants only have value when market prices exceed the variable generation price for the plant. Both market prices and fuel prices are variable within a period such as a month, and fuel prices may correlate with market prices. Fortunately, a well-understood equation provides an estimate of value in the market. This equation is precisely the topic of the section “Thermal Generation.” Because such tricks exist for valuing the individual resources in the market, the valuation approach therefore significantly simplifies estimating system costs.

This concludes the description of variable cost estimation. The next section is on fixed cost treatment.

Real Levelized Costs

The model uses the real levelized (RL) representation of fixed costs, including fixed O&M, fixed fuel, fixed transmission, and construction costs. This section describes the rationale for that choice of representation.

Discounted Cash Flow Inadequate for Comparison[12]

Traditional engineering economics calls for life-cycle cost evaluation, taking into account risk, inflation, and the cost of money. This approach uses nominal cash flows associated with cost and benefit in each period of the analysis, and it discounts the period net cash flows to some fixed point in time. An equivalent approach uses cash flow stated in “real” or constant-year dollars and discounts by a rate that has inflation removed. This

[12] This section borrows heavily from the especially well-written description of real levelized costs that appears in PacifiCorp’s 1992 Integrated Resource Plan, Appendix K.

approach is often referred to as the discounted cash flow (DCF) approach, irrespective of whether current or constant dollars are involved.

The DCF approach is limited in its ability to adequately compare one type of resource asset against another or to compare resources that employ distinct financing mechanisms. The latter is a problem perhaps unique to a regional analysis, which must address the economics of resources using rate-base cost recovery, non-utility equity investment, and the pure debt financing done by BPA, PUDs, and Co-ops.

Consider the problem comparing resources with lives of different lengths, or if the resources are placed in service in different years. For example, the design life of a new pulverized coal generating plant is 40 years, while a simple cycle combustion turbine is 25 years. Ratebase costing results in resource cost that is largest at the beginning of the asset life and declines over time as ratebase is depreciated. Capital resource cost includes depreciation expense, return on ratebase, income taxes and property taxes. Figure L-17depicts the nominal capital resource costs for a $100,000 asset with a 40-year depreciation life and for a $100,000 asset with a 25-year depreciation life.

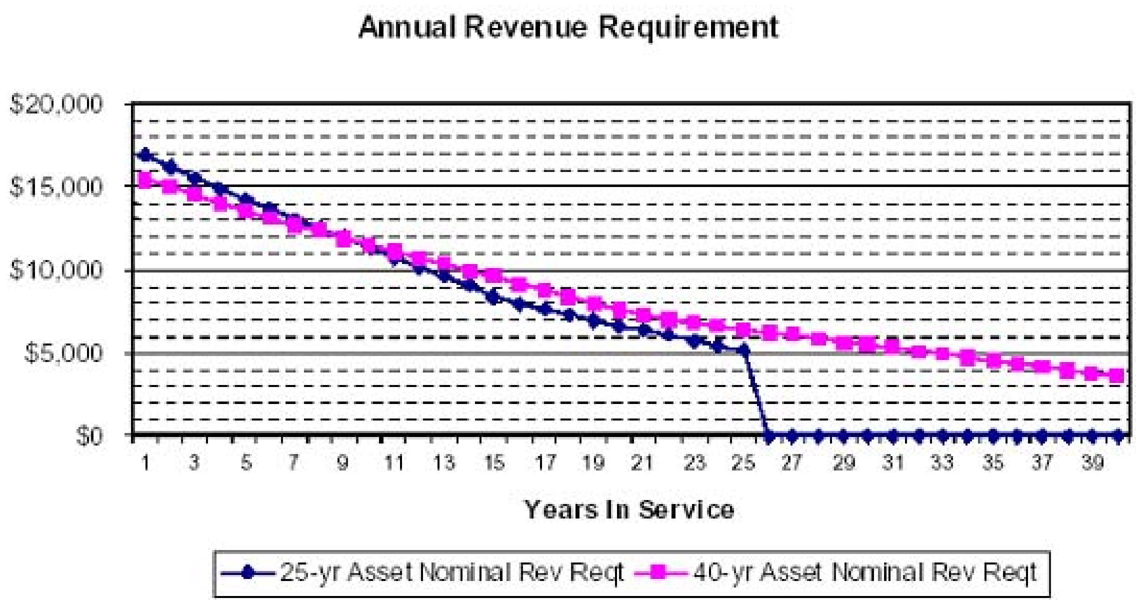

Figure L-17: IOU Revenue Requirements

An analysis mismatch occurs unless the analysis incorporates an adjustment for end-life effects. The “end effect” adjustment recognizes that the 25-year plant must be replaced earlier than the 40-year plant. The adjustment is a continuation of costs with those of the replacement unit. Of course, there must be a similar end-effect adjustment after 40 years, when the second 25-year plant would provide service beyond that of the 40-year asset. And so forth.

An alternative is to extend the analysis period to a length of time that results in the "least common denominator" analysis period. One could illustrate this point with an extreme example. It would take a 200-year analysis to make an equivalent comparison between the 25-year asset and a 40-year asset. The "least common denominator" analysis period would result in eight 25-year assets and five 40-year assets so that the analysis ended with the end-life of both assets. Figure L-18 shows a full 200 years of nominal resource costs for a series of 40-year and 25-year assets using rate-base cost recovery and assuming no real, but 2.5 percent nominal inflation. In this example, the Present Value of Resource costs (PVRR) of both assets is exactly the same. Therefore, if all else were equal in this example, one would be indifferent over this 200-year analysis period between owning a series of 25-year resources or owning a series of 40-year resources.

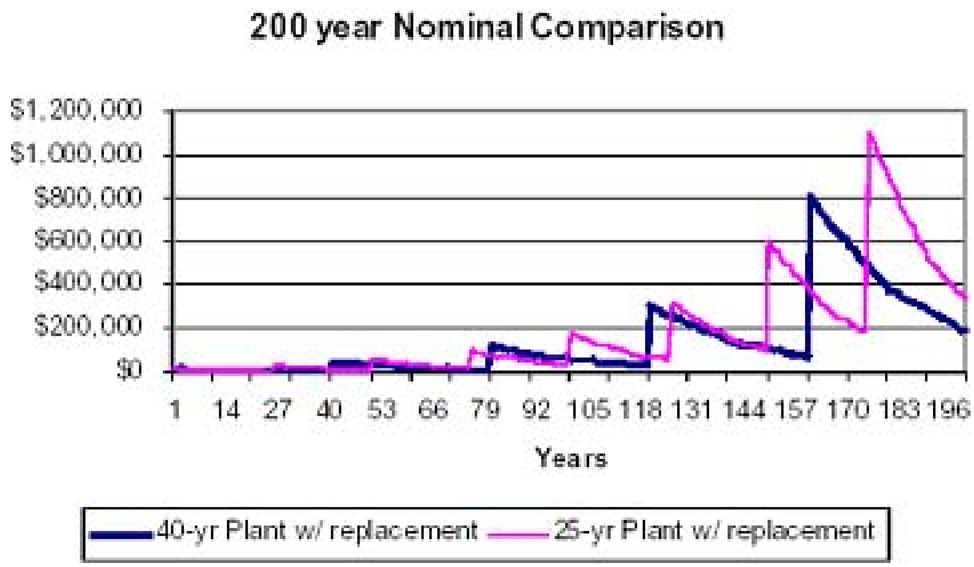

Figure L-18: 200 Year Comparison

Compiling a 200-year analysis is not practical. Even if it were, another common situation, new plants with *equal lives* staggered over the planning period, does not admit the "least common denominator" approach. There is no "least common denominator" of lifetimes in that case. The cash flows illustrated in Figure L-18 do illustrate a point, however. If one is indifferent between assets when considering an "equivalent" analysis period, then what are the results one gets when looking at a more practical analysis period, say 20 years.

Figure L-19 shows the cumulative PVRR of the above resource costs used in Figure L-18. (Cumulative PVRR is derived by taking the present value of each year's resource cost and adding it to the sum of the previous years' present value of resource cost; all discounted at 7.5% in this private utility example to a common time.) Figure L-19 shows only the results of the first 45 years in order to highlight the earlier years. Over an extended analysis period (200 years), the PVRR of both assets is the same.

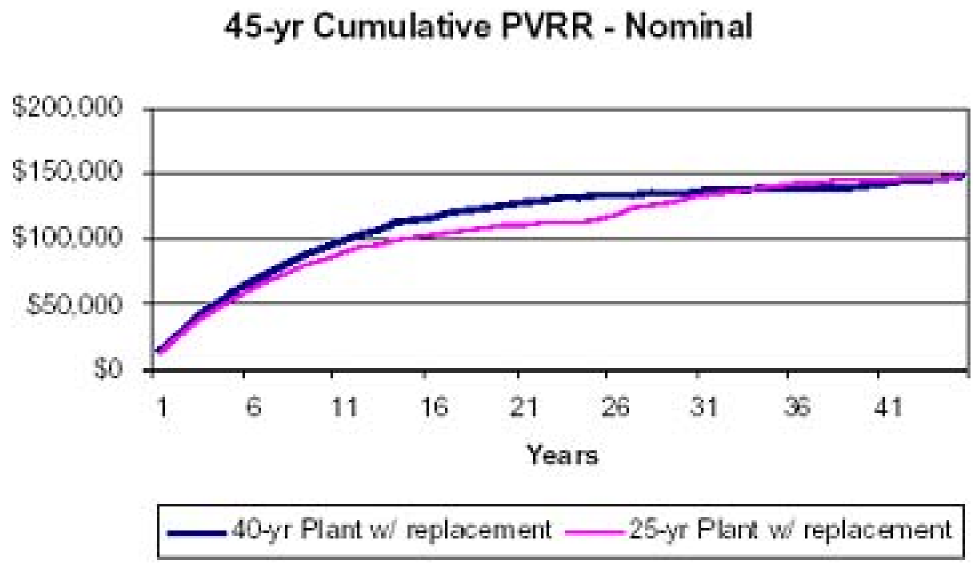

Figure L-19: 45-Year Cumulative PVRR

Figure L-19 clearly illustrates the problem with using DCF costs for comparing resources with different lifetimes. By definition, these assets were valued such that one should be indifferent. However, as can be seen, depending on the length of the analysis period, the nominal resource cost has created a valuation gap between the 40-year asset and the 25-year asset's resource cost. This could lead to misleading conclusions regarding the comparative cost of one resource versus another. DCF costs, without some kind of end-effects adjustment, could result in incorrect analysis findings.

End-effect adjustment calculations can be challenging as well. For example, within a 20-year analysis period, what is the proper adjustment to a 40-year asset and a 25-year asset's cost that will place the analysis on equal footing? There are mathematical formulas for the PVRR of capital projects over an infinite time horizon -- as would be necessary when no "least common denominator" of lives exist. Computing revenue requirements for capital, however, is the least of the problem. It is more difficult to estimate operating costs and benefits of generation, because no simple, regular pattern exists. In particular, there is at least some seasonal variation in such costs and benefits, but what about price spikes, excursions from equilibrium prices, in the last year? What about the effect of annual variation in stream flows and hydrogeneration? These questions apply to all resources, including market purchases and contracts. The answers are as varied as are methodologies to calculate the end-effect adjustment. However, an easier approach allows for comparative analysis between resource options. It provides more representative study results using a practical study period. It consists of using real levelized resource cost.

Real Levelized Resource Cost

Real levelized resource cost is a methodology for converting the year-by-year cash flows into a sequence of fixed constant dollar payments, much like certain kinds of annuities, that has the same present value as the year-by-year cash flows. This approach also easily accommodates both real and nominal cost inflation.

For DCF, the replacement unit causes resource cost to take a huge jump. For real levelized costs, the unit replacement cost continues at the same rate (assuming no real inflation in construction cost). An explanation of how real levelized resource costs are calculated appears in a later section. Figure L-20shows the real levelized resource cost for the same two assets that were shown in Figure L-18, which have no real inflation in construction costs but do have nominal inflation.

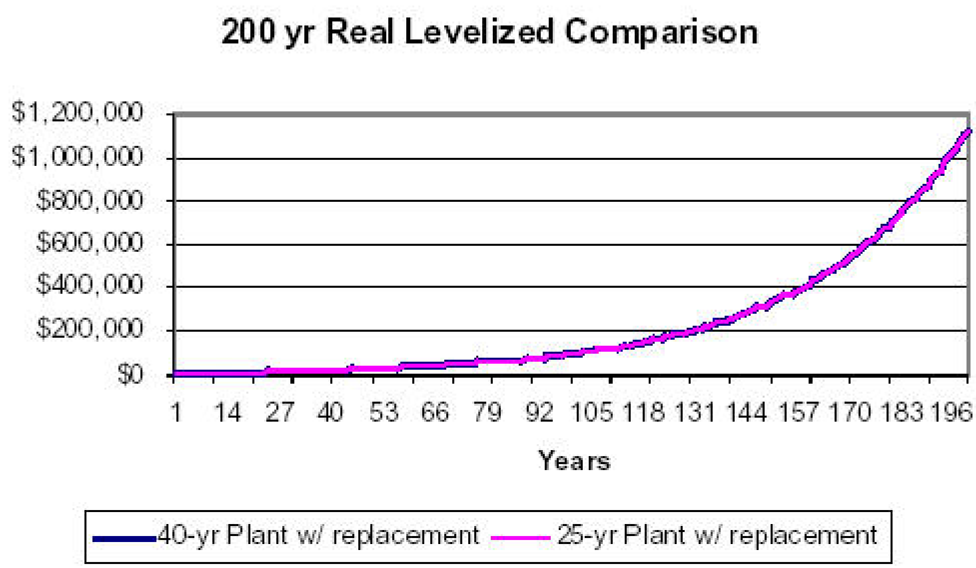

Figure L-20: Comparison (J.6)

Because Figure L-20 uses the same assets as Figure L-18, the PVRR of the resource costs are the same for both assets; hence the real levelized resource cost values for each resource are the same each year. As mentioned earlier, the replacement of the resources throughout time does not create huge jumps in resource costs. Figure L-21 is the same representation as Figure L-19, except that here again, the results are presented using real levelized resource costs. One can see that it does not matter how long the analysis period is, the comparative resource cost valuation is the same at any point in time.

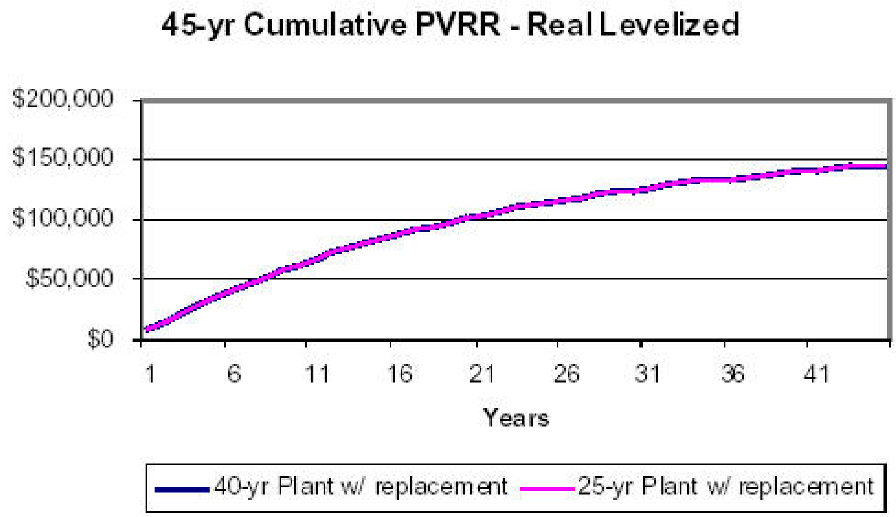

Figure L-21: J-7

So far, the two resources shown have been placed in service on the same date and have been priced to come to the same PVRR over an "equivalent" extended analysis period. This has been solely for the purpose of creating a case that shows that assets of equivalent cost should reflect that equivalent cost, regardless of how long the analysis period is. Real levelized resource costs provide such a case. The advantage of using real levelized resource costs is also extended to an analysis that compares various resources with various lives and various in-service dates. Real levelized resource costs will capture the comparative economic costs with respect to one set of resources being compared against another, without the need for end-effects adjustments.

Economic Decision-Making with Real Levelized Costs

Using real levelized costs for capital investments is more than a practical solution to this resource comparison problem. In accounting, there is a fundamental concept, the "matching principle," that stipulates that the costs for an asset should match the benefits the asset provides. The matching principle underlies a host of commonly accepted accounting practices that have their basis in economics, such as depreciation and rate-base recovery. If costs were not allocated over the useful life of an asset, it could be argued that economic efficiency would not be served. For example, if ratepayers had to pay for electricity in one year enough to recover the entire expense of a power plant, the resulting high price would significantly and inappropriately discourage electricity use. Moreover, costs for the plant would shift to a small group of ratepayers who could not afford to curtail use. In subsequent years, ratepayers would tend to over-use electricity, because they would not see the cost of that plant, despite the fact that they benefit from the plant's availability. Rates that do not match costs to benefits therefore send improper price signals to consumers. Using real levelized costs better reflects how costs apply in this economic, "matching" sense.

A conspicuous example of where some utilities engage in mismatched pricing is conservation. In particular, these utilities expense their investment cost of conservation programs, much like paying the full cost of a power plant in a single year. The reason often given for this practice is the difficulty of providing collateral for financing, which would levelize the conservation cost. That is, if the utility defaulted on its loans, it would be impractical and pointless for investors to remove conservation from utility customers' homes and businesses for resale. This is not the case with a power plant, which investors can sell to recover from default. Without this financing, however, either the ratepayer pays all conservation costs up front or the utility effectively makes an unsecured loan to the ratepayer. The first alternative creates uneconomic price signals. The second alternative requires the utility to burden its own balance sheet and hope for fair regulatory treatment in the future. Neither of these alternatives is attractive. The Council's solution to this situation is the Plan's Action Item **CNSV-11**, which calls for state-guaranteed utility (or non-utility) financing, assured through the state's taxing authority.

To prepare the RL costs for the portfolio model, life-cycle fixed plant costs, including construction and interest during construction, are discounted using the rate appropriate for the financing and accounting. For example, the Generation Resource Advisory Committee (GRAC) made determinations about which types of agencies would most likely build wind plants, coal plants, and so forth. Often, the GRAC arrived at a participation-weighted balance of financing, using a blend of private IOU, federal, and public investment. The present value calculation uses the blended discount rate. To levelize the present value the Council should have used its four percent discount rate. However, due to an oversight, the costs in the regional model runs were levelized at the blended after-tax cost of capital (4.9%) [**2**]. Finally, the portfolio model uses four percent to discount the real levelized quantities, adjusted for real cost escalation, over the study period. The section "Present Value Calculation," below, describes the formulas in the portfolio model that perform this task.

Comparison to Market Purchases

As explained in the previous section, the portfolio model uses valuation in the market for estimating variable system costs and benefits. The year-by-year capital resource cost in Figure L-17 shows the front-end loaded resource cost for capital investment typical of a private utility. How does this cost compare with the alternative of market purchases? Any analysis period short of a full asset life-cycle analysis will overstate the capital resource costs in the early years, while leaving the lower cost later years out of the analysis. With a 20-year analysis period, using cash flows for resource capital will overstate the comparative cost of long-lived resources. Restating the issue a different way, consider two groups of customers in a rising market price environment. Customer Group A will get to use and pay for a 40-year resource during the analysis period, say, the first 15 years, and Customer Group B will get to use and pay for the resource during the remaining plant life, or 25 years. Without some kind of adjustment, simple DCF resource costs would cause Group A to pay all the higher cost years, when market price is lower, while Group B would get to pay for all the lower cost years when market price is higher. This is hardly a fair allocation of resource costs among Customer Groups A and B when comparing the resource cost to market purchases.

Shortcomings and Disadvantages

Absent 20/20 foresight, any analysis methodology will have its challenges, and real levelized costs are no exception. Implicit in the use of this technique is the assumption that the future, beyond the horizon of the study, either does not make much difference to today's economic decision or will be economically similar to the study period. The former is true when the discount rate is large and the impact of cash flows beyond study period is negligible. The four percent discount rate used by the Council is probably toward the lower end of rates for which that argument might apply.

The latter assumption may hold in many circumstances, but there are situations where we expect it would not. For example, a carbon penalty imposed late in the study period would probably extent well beyond the study horizon. Such a carbon tax would have a disproportionate impact on coal plants. A coal plant built several years before the carbon tax arises may see economically productive years before the tax and harder times after the tax. Because the carbon tax is a variable cost of operation, and not included in the real levelized capital cost, the study would only see the balance of these, weighed by their relative term within the study and not the less attractive economics after the study.

There are several possible accommodations for this shortcoming. One is the consideration of some end effects, perhaps using the last year of analysis. This section has already discussed the associated difficulties with this approach. Nevertheless, in subsequent studies such adjustments might make reasonable sensitivities. Another accommodation, which the Council uses instead, is simply to ask whether the recommended plan would have changed if a carbon tax had more severely penalized coal-fired and, to a lesser extent, gas-fired generation. The Council concluded it would not. The plan prepares the region for significant amounts of conservation and wind generation. The amount of early coal is small, a single 400 MW unit. The timing and amount of this early coal permits re-evaluation before licensing and siting begins. By then, additional information about the likelihood of carbon penalties will be available. Gas-fired generation does not appear until late in the study period. The arguments regarding licensing and siting pertain to an even greater degree. For the Action Plan period, the plan merely calls for securing siting and licensing options for these fossil fuel-fired plants.

In summary, the portfolio model covers a 20-year forecast period. During this forecast period, the model is comparing the alternative resources available to determine the risk-constrained, least-cost plan. Because many of the potential resources have economic lives which extend beyond the analysis period and have lives of various lengths, appropriate methods are necessary to capture the comparative costs of such capital-intensive investments. Alternative financing and accounting methods can also distort the economic evaluation of such resources. An end-effects adjustment is feasible, but the value of those end-effects can be difficult to determine. An alternative approach, which the portfolio model uses, is real levelized capital resource cost. Real levelized cost eliminates the need for an end-effects adjustment, and provides a reasonable approach for comparing the cost of capital resources against each other and also against market purchase resources. Real levelized resource costs may not fit all analysis situations. Care must be taken when events near the end of the study, such as the emergence of a carbon penalty, create situations that extend beyond the study period and may render study results non-representative. Nevertheless, when used with care, real levelized capital costs can do a better job of reflecting the true economic costs of capital resources than simple DCF methods.

This concludes the preamble to single-period calculations. As explained in the previous section, Appendix P provides extensive discussions of how the model computes values for loads, natural gas, and other aspects of a future. Prior periods' electricity prices or other factors can then modify these in the Twilight Zone illustrated in Figure L-6. If there are any such modifications, the discussion is in the section "Multiple Periods," which follows below. The remaining portion of this section on single-period calculation picks up the calculation after any modification in the Twilight Zone.

Loads

Appendix P describes the construction of quarterly energy requirements before any adjustments due to the choice of plan. The plan *does* affect loads, however, as the amount of capacity available affects the price for wholesale electricity, and wholesale electricity prices have a long-term effect on loads because of price elasticity. See page L-59 in the section "Multiple Periods" for this treatment.

The **energy calculation** in {AQ322} is simply the product of the elasticity effect {AQ321}, the on-peak portion of load in MWa {AQ183}, and the number of hours on-peak in a standard quarter.

One of the conventions the model design tries to adhere to is to avoiding putting data into code or formulas. Admittedly, this version of the regional portfolio model is not always successful in achieving that objective. Nevertheless, some kinds of numbers arguably could appear in formulas. For example, the number of days in a week and the number of months in a year will not change, so burying them in code presents little risk to some future user who might want to make changes to the model. Because the design of the regional portfolio model permits only one particular definition of the period, namely the standard quarter, the number of on-peak hours in a standard quarter is a fixed constant and therefore would be an exception to this rule.

Calculating the **cost of meeting that load** in {AQ323} uses the valuation approach. Specifically, the cost is the average energy {AQ322} times the average on-peak period market price {AQ204} times a special factor that incorporates the correlation of loads and market prices. The cost is divided by 10^6 to restate the dollars in millions of 2004 dollars.

The special factor is (1+$S$14*$O$322), where $S$14 is the correlation between non-DSI loads and power prices and $O$322 is a fixed constant. The fixed constant is calculated in cell $O$322 from the formula

SQRT(EXP($R$184^2+$R$201^2)-EXP(R184^2)-EXP(R201^2)+1)

The value in \$R\$184 is the on-peak intra-period load variation; the value \$R\$201 is the on-peak intra-period electricity price variation. The complexity of this equation stems from the fact that the definitions of the load and price variations are slightly different from a simple standard deviation of load or price.

Appendix P lays out the justification for use of lognormal distributions for load and price. The variations that appear in \$R\$184 and \$R\$201 are the standard deviations of the log-transformed loads and prices. There is, however, a well-known relationship between the mean and standard deviation of the transformed and non-transformed variables.[13] If ***E(p)*** and $\boldsymbol{\sigma_p}$ denote the expected price and standard deviation after log transformation and ***E(P)*** and $\boldsymbol{\sigma_P}$ before transformation, and similarly and ***E(q)***, $\boldsymbol{\sigma_q}$, ***E(Q)*** and $\boldsymbol{\sigma_Q}$ for quantity, the relationship for standard deviations is

$$\sigma_Q = E(Q)(e^{\sigma_q^2} - 1)^{1/2}$$

$$\sigma_P = E(P)(e^{\sigma_p^2} - 1)^{1/2}$$

The correlation used in this calculation is a ranked correlation, so the correlation is unaffected by transformation. From equation (1) above, the expected revenue is

$$\begin{aligned} E(PQ) &= E(P)E(Q) + \sigma_P \sigma_Q \rho_{PQ} \\ &= E(P)E(Q) + E(P)(e^{\sigma_p^2} - 1)^{1/2} \sigma_Q E(Q)(e^{\sigma_q^2} - 1)^{1/2} \rho_{pq} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p^2} - 1)^{1/2}(e^{\sigma_q^2} - 1)^{1/2} \rho_{pq}\right\} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p^2 + \sigma_q^2} - e^{\sigma_p^2} - e^{\sigma_q^2} + 1)^{1/2} \rho_{pq}\right\} \end{aligned}$$

This is the formula in cell {AQ323}.

The on-peak non-DSI costs present-valued in {CV323}. The formula is described on page L-79, in the section, "Present Value Calculation."

DSI interruptions can be of a short-term nature, such as hourly or daily curtailments, or they can be long-term. Long-term interruptions involve smelter shutdowns and startups. The portfolio model assumes that demand response, discussed below, captures short-term interruptions. Energy and cost calculations for long-term price induced interruptions of DSI on-peak load are in the range {AQ327:AQ329}. Indeed, the name of this behavior is Long Term Price Responsive Demand or LTPRD, and the acronym appears several places in the worksheet. The capacity in {AQ327} depends on smelters shutting down and restarting, behavior that requires understanding of choices made over several periods. Description of modeling DSI capacity therefore is in its own section on page L-60.

The **energy calculation** for DSIs is in {AQ328}. The formula is the product of the DSI total capacity and the number of on-peak hours in a standard quarter.

[13] See Hull, John C., ***Options, Futures, and Other Derivatives***, 3rd Ed., copyright 1997, Prentice-Hall, Upper Saddle River, NJ., ISBN 0-13-186479-3, page 230

Calculating the **cost of meeting that load** in {AQ329} uses the valuation approach. The long-term capacity is uncorrelated with short-term electricity price variation, so the cost is simply the product of the energy and the average on-peak price. It is divided by 10^6 to restate the dollars in millions of 2004 dollars. The costs are present valued in {CV329}.

Off-peak calculations begin in the second half of the worksheet {row 684}. The calculations for off-peak non-DSI loads and costs are in {AQ687:AQ688} and the DSI loads and costs are in {AQ692:AQ693}. These calculations are identical to those for on peak, except in obvious ways. The formulas use the number of off-peak hours in a standard quarter (864) and off-peak electricity prices. The off-peak long-term demand for DSI loads is the same as on-peak demand.

Thermal Generation

The model estimates hourly generation dispatch and value. Moving down from the load calculations, the first of these appears in range {AQ339:AQ340}, associated with PNW West NG 5_006. (A description of this gas-fired resource and of the modeling values that this resource uses appears in the section "Existing Resources" on page L-92, below.) The value in AQ339 is the energy in MWh and AQ340 is the cost in millions of 2004 dollars. A single call to a user-defined Excel function (UDF) returns these values as a vector of two single precision real numbers.

This section begins with an explanation of how the regional portfolio model estimates thermal dispatch and value, assuming fixed fuel price. It then generalizes this approach to the case where both electricity price and fuel price are possibly correlated stochastic variables. Finally, it documents the Excel user-defined function that implements the logic. It also points out the analogies between these calculations and financial, European call options and exchange-of-assets options.

Thermal resources dispatch whenever the market price of electricity exceeds their short-run marginal cost. The short-run marginal cost includes cost for fuel and variable operations and maintenance (O&M). For example, assume a gas turbine with a capacity of 1.0 MW has a short-run marginal cost of $30/MWh. For the sake of this illustration, the O&M cost is zero and all the short-run cost is fuel cost. The turbine faces a market price that varies regularly over some period, say a month with 672 hours. When the market price is greater than the fuel price, the turbine dispatches, as illustrated by the red area in Figure L-22.

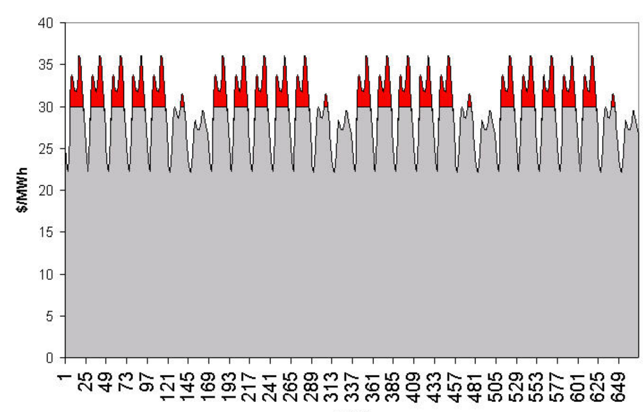

Figure L-22: Thermal Dispatch

In each hour, the value of this generation is the difference between what the generation earns in the market, the market price, and what it costs to generate the power, the short-run marginal cost. The value of the turbine over the month is the sum of the hourly values.

To make the valuation more quantitative, first note that the hourly value is ***$C\ max(0, p_e(h)-p_g(h))$***, where ***C*** is the capacity of the turbine, ***$p_e(h)$*** is the price of electricity and ***$p_g(h)$*** is the price of gas denominated in \$/MWh, i.e., the short-run marginal cost of the turbine. This is just the height of the red area in Figure L-22 in each hour. Note that it is never negative, because the turbine does not dispatch unless it can add value. Summing up the value across hours is just

$$V = \sum_{h \in H} C \cdot \max(0, (p_e(h) - p_g(h)))$$

where

H is the set of hours (672 in this case)

$p_e(h)$ is the price of electricity in this hour (\$/MWh)

$p_g(h)$ is the price of gas in this hour,

assuming a fixed heat rate (\$/MWh)

C is the capacity of the turbine (1 MW in our case)

Restating the total value in terms of the mean or average value over the period, and interpreting this as the expected mean of a sample drawn from the population of values, the total value is

$$\begin{aligned} V &= C \sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right) \\ &= CN_H \frac{\sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)}{N_H} \end{aligned}$$

or

$$V = CN_H E\left[\max\left(0, p_e(h) - p_g(h)\right)\right] \qquad (3)$$

where ***E*** is the expectation operator and ***N_H*** is the number of hours in the period (672 in this case).

The expectation in this formula is (See reference [**3**]):

$$c = \overline{p}_e N(d_1) - p_g N(d_2) \qquad (4)$$

where

N is the CDF for a $N(0,1)$ random variable

$\overline{p}_e$ is the average electricity price

p_g is the gas price

σ_e is standard deviation of $\ln(p_e(h))$

$$d_1 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} + \sigma_e / 2$$

$$d_2 = d_1 - \sigma_e$$

The turbine is therefore $\boldsymbol{V = CN_H c}$. Those familiar with financial derivatives theory will recognize the similarity of this equation to that of a European call option[14].

If we sort the hours illustrated in Figure L-22 by the market price, we obtain the market price duration curve in Figure L-23. This aggregation creates a simple area under the market price curve that corresponds to the value of the turbine. Flipping this duration curve over as in Figure L-24 creates a cumulative distribution function (CDF). The value of the CDF is the likelihood that electricity prices will exceed the values on the horizontal axis, if one drew an hour at random from the month. The red area to the left of the short-run marginal cost of $30/MWh is the expected value of turbine dispatch.[15]

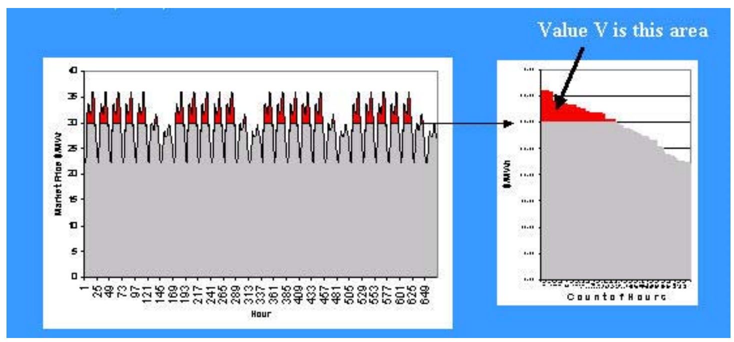

Figure L-23: Sorting by Market Price

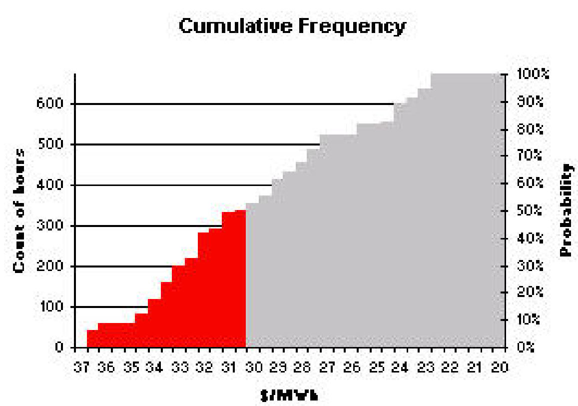

Figure L-24: Cumulative Probability Function

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[14] See for example, Hull, op. cit., page 241. Set r = 0, T = 1, X = p_g, $\sigma_s = \sigma_e$, and S equal to the average of the hourly electricity prices $p_e(h)$. This is the version of the equation for a stock that pays no dividends.

[15] This is completely analogous, however, with the valuation of an option. For an option, the value derives from the expected stock price above the strike price, given the likelihood distribution of prices at expiration. Whereas the volatility (standard deviation) of stock prices describes the width of the corresponding probability density function, here it describes the width of the probability density function for electricity prices during the month.

Although estimating the value of the turbine in the electricity market is essential for calculating system costs, **estimating the energy generation** of the turbine is equally important. At a minimum, we need to know its energy generation to determine whether the total system is in balance with respect to energy. That is, we need to know whether the electricity prices the model is using are generating more energy than system requirement plus exports. If so, prices are too high. Similarly, if the prices are inducing the generation of too little energy to meet requirements, given imports, the prices are too low.

To estimate generation, note that the CDF for generation already specifies the capacity factor for the turbine, as illustrated in Figure L-25. The energy will correspond closely to the hours of generation because for those hours when prices make generation economic, the optimal loading is loading to the lowest average heat rate, which is the plant's assumed maximal loading. The generation would therefore be the capacity of the turbine times the number of hours in the period, times the capacity factor. The function that computes the value of the power plant unfortunately cannot make use of this graphical representation for capacity factor and must resort to more algebraic devices. There is, however, an algebraic relationship between the value of an option (or turbine) and the dispatch factor.

The CDF is a function of $\boldsymbol{p_e}$, and the expectation $\boldsymbol{E(0,p_e(h)-p_g(h))}$ is the integral of the CDF($\boldsymbol{p_e}$) for $\boldsymbol{p_e}$ from infinity down to $\boldsymbol{p_g}$. Moreover, the capacity factor is just CDF($\boldsymbol{p_g}$). These relationships are evident from Figure L-25. Algebraically, the capacity factor ***cf*** is derived as follows:

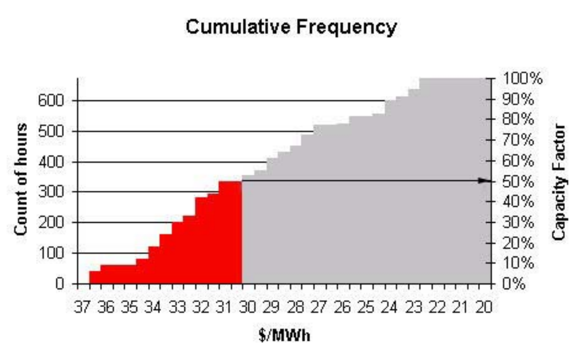


Figure L-25: Capacity Factor

$$V = C \cdot N_H \int_{\infty}^{P_g} \mathrm{CDF}(p_e)\, dp_e$$

$\Rightarrow$ (Fund Thm of Calculus)

$$\left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*} = -C \cdot N_H \cdot \mathrm{CDF}(p_g^{\ *})$$

$\Rightarrow$

$$\mathrm{cf} = \mathrm{CDF}(p_g^{\ *}) = -\frac{1}{C \cdot N_H} \left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*}$$

To find the value of the partial derivative in the last equation, use the fact that $\boldsymbol{V=CN_Hc}$ and take the derivative of equation (4) with respect to the strike price [**4**].

$$\frac{\partial c}{\partial p_g} = -N(d_2)$$

where

$$d_2 = \frac{\ln(\bar{p}_e / p_g)}{\sigma_e} - \sigma_e / 2$$

This gives us an explicit formula for the capacity factor, and hence energy, as a function of the gas and electricity price.

$$\mathrm{cf}(p_g, \bar{p}_e) = N(d_2)$$
$$d_2 = \frac{\ln(\bar{p}_e / p_g)}{\sigma_e} - \frac{\sigma_e}{2}$$

Those who are familiar with option theory recognize that ***$N(d_2)$*** is the probability that the strike price is paid for an option, that is, the probability that the option is "in the money" upon expiration. This is consistent with the earlier observation (footnote 15) that capacity factor is the likelihood that electricity prices will exceed the short-run marginal cost of $30/MWh, if one drew an hour at random from the month.

Up to now, we have assumed that the gas price is fixed. The problem with that assumption, of course, is that gas prices do change and may correlate with electricity prices. The value of generation is still given by equation (3), but now both ***$p_e(h)$*** and ***$p_g(h)$*** are stochastic variables. Doing this directly introduces some computational problems[16], but by taking a slight rearrangement of equation (3), we obtain

$$V = E\left[S_2 \max\left(0, \frac{S_1}{S_2} - 1 \right) \right]$$
$$S_2 = CN_H p_g(h)$$
$$S_2 = CN_H p_e(h)$$

If we assume lognormal distribution for both electricity and gas prices, the preceding equation may be evaluated explicitly:

[16] One approach to solving this issue is to use a "spread option." The value of a spread option derives from the difference in price between two commodities, in our case electricity and natural gas (assuming some conversion efficiency). The problem with a general spread option, however, is that when the strike price is near the expected commodity price, the equations above do not work, so a more sophisticated approach is necessary, which involves solving some integral equations. Finding the solutions to the integral equations, unfortunately, is slow and somewhat unstable. Moreover, the spread option is unnecessarily general because, for the turbine, value derives from differences in only one "direction," that is, when electricity prices are strictly higher than gas prices.

$$
\begin{aligned}
&V = \varepsilon = S_1 N(d_1) - S_2 N(d_2) \\
&cf(\overline{p}_g, \overline{p}_e) = N(d_2) \\
&d_1 = \frac{\ln(S_1 / S_2)}{\sigma} + \sigma / 2 \\
&d_2 = d_1 - \sigma \\
&\sigma = \sqrt{\sigma_{S_1}{}^2 + \sigma_{S_2}{}^2 - 2\rho\sigma_{S_1}\sigma_{S_2}} \\
&\text{where} \\
&S_1 = \mathrm{CN_H}(\overline{p}_e - p_{VOM})(1 - FOR) \\
&S_2 = \mathrm{CN_H}(\overline{p}_g + p_{CO_2})(1 - FOR) \\
&p_{VOM} \text{ is the variable O \& M rate (\$/MWh)} \\
&p_{CO_2} \text{ is the carbon tax penalty (\$/MWh)} \\
&\sigma_{S_1} \text{ is standard deviation for } \ln(\mathrm{S_{1,t}} / S_{1,t-1}) \approx \ln(p_{e,t} / p_{e,t-1}) \\
&\sigma_{S_2} \text{ is standard deviation for } \ln(\mathrm{S_{2,t}} / S_{2,t-1}) \approx \ln(p_{g,t} / p_{g,t-1}) \\
&\rho \quad \text{is the correlation in values between } S_1 \text{ and } S_2 \\
&FOR \text{ is the unit's forced outage rate } (0 \le FOR \le 1.0)
\end{aligned}
$$

where, as before, we have adjusted the price of gas ($/MMBTU) and the price of the CO_2 tax ($/MMBTU) to $/MWh using the assumed heat rate (BTU/kWh) of the unit. Also, this formula introduces the forced outage rate (FOR) for the unit, which limits the amount of energy that the unit can produce.[17] Note that the variables S1 and S2 here are total values, not prices. This means that, whereas in the case of deterministic ***$p_g(h)$***, the value V = CNHc used the quantity CNH times the unit value c, we now have V = ε.

The portfolio model performs this calculation through an Excel UDF. The range {AQ339:AQ340}, associated with PNW West NG 5_006, contains a vector-valued function. This function returns two single-precision real numbers, one for the energy and one for the value in millions of 2004 dollars. The call in {AQ339:AQ340} is

```
=SpreadOption( $P339, AQ$46,AQ$204-$R$337,AQ$68+0.059*AQ$74,(1-AQ336)*1152*$S$335,(1-AQ336)*1152*$S$335*9.2,1,0,0,0,$R$201,$R$55,$T$14)
```

The function's declaration[18] for the parameters is

[17] Those familiar with financial derivative theory will recognize the similarity to the value for an exchange option that pays no dividends (See, for example, Hull, op. cit., page 468, and note that S1 and S2 are reversed here from the notation Hull uses.) Using the convention T = 1, S1 for the average of the hourly values for electricity generation, and S2 for the average of the hourly values of gas that we must hold to produce the generation.

[18] Although the function's name is "SpreadOption," examination of the code will reveal that it is really the exchange option described above.

```
Function SpreadOption(ByVal lPlant As Long, ByVal lPeriod As Long, _
    ByVal dblSp1 As Double, ByVal dblSp2 As Double, _
    ByVal dblQuan1 As Double, ByVal dblQuan2 As Double, _
    ByVal dblTime As Double, ByVal dblIntRate As Double, _
    ByVal dblYeild1 As Double, ByVal dblYeild2 As Double, _
    ByVal dblVol1 As Double, ByVal dblVol2 As Double, ByVal dblCorr As Double) _
        As Variant
```

The parameters are as follows

lPlant As Long	a zero-based index of plant, on- and off-peak plants modeled separately
lPeriod As Long	a one-based index of period
dblSp1 As Double	price ($/MWh) for electricity, less VOM
dblSp2 As Double	price ($/MMBTU) for fuel, including CO2 tax
dblQuan1 As Double	MWh of electricity
dblQuan2 As Double	MMBTU of fuel
dblTime As Double	time to expiration (years) = 1 for plant dispatch purposes
dblIntRate As Double	annual interest rate for yields (not used)
dblYeild1 As Double	yield on commodity 1 (electricity, not used)
dblYeild2 As Double	yield on commodity 2 (natural gas, not used)
dblVol1 As Double	variation in electricity price within the period
dblVol2 As Double	variation in fuel price within the period
dblCorr As Double	correlation between electricity price and fuel price

The only parameter inputs that should require description beyond what the section already has provided are the following. The parameter dblSp2 uses converted cost of a tax in $/U.S. short ton of CO_2. The conversion to $/MMBTU is

$$\$/MMBTU = \frac{\$}{ton}\frac{ton}{lb}\frac{lb}{MMBTU}$$

where tons per lb is 1/2000, methane combustion produces 117 pounds of CO_2 per MMBTU, and carbon produces 212 pounds of CO_2 per MMBTU. For a gas-fired turbine, the conversion to dollars per million BTU from dollars per ton is 0.059, which appears in the example of the function call, above. The quantities dblQuan1 and dblQuan2 in the function call, above, also use 1152, the on-peak hours per standard hydro quarter. Finally, the value for the dblQuan2 parameter uses 9.2 kBTU/kWh, which is the assumed heat rate for this particular unit.

Contracts

For the purposes of the portfolio model, contracts are risk-management agreements that make future price and delivery of energy more certain. The regional model does not address contracts between parties within the region, because the region as a whole is indifferent to such arrangements. Consequently, only contracts between the region and counterparties outside of the region are material.

The regional model assumes most existing contracts are fixed-price, forward contacts for specific quantities of energy. Such contracts are agreements to pay a fixed sum for energy upon delivery. New contracts were not included among new resource candidates for reasons explained later in this section.

There are two aspects of contracts that impact regional risk: power flows and economic flows. Power flows potentially influence market price and dispatch; money flows impact economic predictability. The next two sections discuss these distinct aspects of contracts.

Power Flow

To understand how existing, firm contracts for energy sales out of the region affect power flow, market price, and dispatch, we consider a simplified example. In this example, only contracts with California exist. There are three cases to consider: uncongested transmission between the region and California, congested transmission with power flows headed north from outside the region into the region, and congested transmission with power flows headed south.

If transmission is not congested, market price in the region are substantially the same as that outside the region and it makes little difference whether or not the firm contracts exist. Wholesale market prices in the region would be the same with and without these firm contracts. The single market price would determine dispatch of plants both in and outside the region.

If transmission flow is congested in the northern direction, this means that market prices in the region are higher than market prices south of the region. In this case, and generators would be better off selling power into the higher-priced regional market and meeting their commitment to the southern counterparty with market purchases from the southern market. The counterparty, of course, would be indifferent to this arrangement, because the parties would have previously agreed upon price.

If transmission is congested southbound, market prices in the region are lower than market prices south of the region. Assume a regional generator is dispatching out of economic order, given regional load plus export limit, to meet contract requirements. First, consider the situation where the generator is dispatching when its cost is above regional market price. This makes no sense because the generator could buy in the regional market, shut down his plant, and make a profit by making the contract obligation with the market purchase. Second, consider the situation where the generator is not dispatching when its cost is below regional market price. The generator must meet its obligation to the contract, which leaves it two options. It could buy from the regional market, but that is more costly than dispatching. Alternatively, it could buy out of the southern market to meet the obligation, but that is even more costly. In this situation, the plant again dispatches at the regional market price. Certainly, the distribution of profits in this case depends on which generators have transmission rights, but the dispatch order of plants and consequently the market prices are unaffected by the contract.

What this discussion shows is that contracts do not affect power plant dispatch decisions or market prices, either within or outside the region. The dispatch and regional market price are unaffected by contracts, irrespective of who owns the generation projects or whether the regional load or an independent power producer (IPP) gets the value of the generation. Although the example is for an export contract, some thought will convince the reader that it applies to an import contract, as well. The ability to counter schedule contracts assures that the fundamental economics of power plants will determine their dispatch and the resulting market prices.

Modeling counter scheduling opportunities is important to the regional model and shows up explicitly in calculations. To illustrate the calculation, consider the region as a tank with a single pipe for importing and exporting energy as illustrated in Figure L-26. We can think of the transmission capability of the this simple system as the symmetric flow capability of the pipe, 5000 MW in both directions in this example.

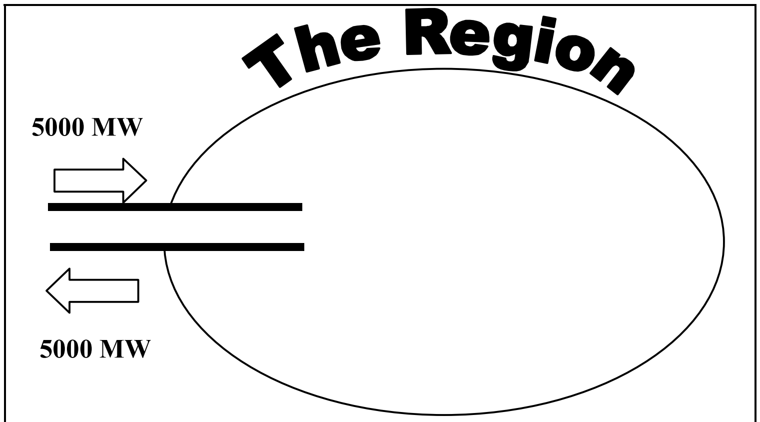


Figure L-26: Transmission Before Contracts

Now, we consider the situation where the model represents an energy import contract as a resource in the region. If we have 3000 MW of additional energy available to region by virtue of the import, there is an implied flow of energy over the transmission system into the region of 3000 MW. This, in turn, means we have only 2000 MW of net transmission capability left for remaining contracts or spot purchases from outside the region. By the same token, the import can be counter scheduled, which adds 3000 MW for remaining export contracts or spot sales to outside the region. Consequently, the net import and export capability of the region must be adjusted to reflect any firm contracts into or out of the region, as shown in Figure L-27.

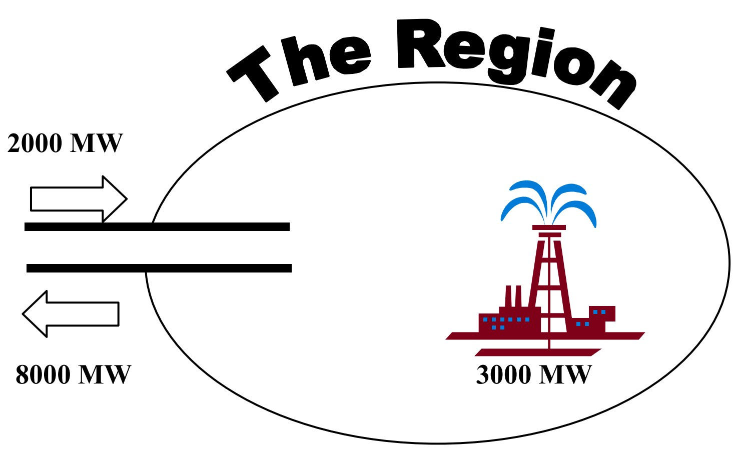


Figure L-27: Transmission After Contracts

In the workbook, the on- and off-peak average energies (MWa) appear initially in {rows 84 and 88} respectively. The data values are presented and documented below, in the subsection "Contracts" of the section "Resource Implementation and Data." These MWa values are used by the calculation of annual energy for the decision criteria in {row 290} (see e.g., {AT290}), for a estimate of Non-Hydro Capacity ({row 670}) used by certain reports (see the section "Portfolio Model Reports And Utilities"), and in the contribution to regional energy balance. For the regional energy balance calculation, the worksheet first converts MWa to MWh using the number of standard hours in the subperiod ({rows 367 and 731}). The value calculation {AQ368} uses MWh equivalent and the relevant market price to determine cost or value of the contract. For reasons described in the next section, the worksheet computes only the gross value, assuming the costs for these fixed contracts effectively are sunk. The energy requirements calculation { AQ676 and AQ1032} uses the MWh equivalent to determine the necessary purchases on the market. The adjustment to import and export capability, illustrated in Figure L-27 is reflected in calculations at { AQ677 and AQ1033}.

Money Flows

Contracts reduce risk to the parties by assuring financial certainty. Irrespective of factors that may influence the dispatch of resources, some party is responsible for delivering power to a particular substation at an agreed-upon price.

The portfolio model captures economic consequences of resource decisions to an unprecedented extent, but there are still limitations to what we have modeled. One of the practical constraints is our limited knowledge of the financial terms of existing and new contracts. The portfolio model incorporates energy flow associated with existing long-term contracts, but unfortunately the Council has no basis for estimating contract costs. It is assumed that existing contracts have fixed-price and fixed-energy terms, and the costs of the contracts are therefore sunk. The gross value of these contracts, however, is valued in the market. Thus, we capture the cost of meeting future requirements and value contract deliveries to the region. Because the energy is constant over each subperiod, the correlation with market price is zero and the calculation of the gross value is simply the product of average market price and energy, as shown in {AQ368}. All dollar amounts are in millions, so the formula divides the product by 1,000,000.

Although a single utility's risk model would do so, the regional model does not examine ***future*** contracts the region might enter into either with IPPs or with entities outside of the region. Although such contracts would certainly affect the economic risk situation for the region and for parties within the region, the regional model avoids modeling these contracts for several reasons.

- The terms of future contracts are hard to predict. Perhaps the best guess would be to set future contract prices at the prevailing market price. Unless the model assumed detailed rules for entering into fixed-term contracts -- the begin date and duration of the contracts, the amount of transmission left to accommodate the contract, and so forth -- the terms would have to float with the market price. In this case, however, the value of the contract would then be zero. That is, there is no point to explicitly modeling the contract.

- Contracts for regional load-serving entities and regional IPP capacity with parties outside the region would remove sources of contracts for regional parties, but arguable displace other sources outside of the region. Given the load diversity in the WECC, it stands to reason that contracts for power will continue to be more abundant in the winter, when the region needs the capacity.

Thus, while future contracts for energy out of the region could affect economic risk by hedging price risk and removing or adding contracting counterparties for the region, the model does not capture this. The practical limits on knowledge of existing and future terms and the small likelihood that such contracts would significantly diminish the pool counterparties for regional participants are significant hurdles to such modeling.

Before leaving this section, note that the value or cost associated with contracts accrues to the region in the base case model. As the reader will note in the discussion of the regional IPP sensitivity (Appendix P), this is not always the case. That is, the energy of contracts may affect the energy balance of the region before any counter-scheduling, but the associated costs may be excluded from the region's cost estimate. This occurs, for example, if the regional IPPs have firm contracts to export energy out of the region. This obligation is on the IPPs -- not the region -- and should not affect regional costs. The energy export will offset the generation of the IPPs in the region, however.

Supply Curves

The model uses supply curves to represent conservation and price-responsive hydro. For the purposes of the regional model, conservation is either discretionary or of a lost-opportunity nature. Price-responsiveness of hydrogeneration refers to a limited capability to shift hydrogeneration from month to month in response to wholesale electricity market prices. Do not confuse price-responsive hydrogeneration with what is often called "hydro flexibility," which refers to the ability of the hydrogeneration system to draw below Energy Content Curve (ECC) under adverse conditions for reliability purposes. The hydro flexibility capability of the region is over 7,200 GWh or about 10,000 MW-mo. The region uses this flexibility for severe situations, like extreme winter load conditions, and it comes usually at the cost of some non-hydrogeneration use of the system, such as fish survival enhancement. On the other hand, the magnitude of price-responsive hydrogeneration response is relatively small, about 1500MW-mo. Price-responsive hydrogeneration reflects adjustments that operators would make in anticipation of market conditions, and they perform these adjustments with energy above the ECC.

Background

To begin the description of the supply curve logic, consider the physical and economic situations to be modeled. The first example is lost-opportunity conservation, including a more detailed discussion of the model determines cost from the supply curve. The section then describes the examples of discretionary conservation and price-responsive hydrogeneration.

Lost opportunity conservation consists of energy saving opportunities that are available for only a limited time. Examples of these include insulating and the installation of high-efficiency heating and cooling systems in new buildings. After their construction, going back and changing the conservation measures in these buildings would be cost prohibitive. Special attributes of this kind of resource are the following:

- Assuming the same measures are available to all new buildings, there is effectively a new supply curve in each period. The supply curve consists of the aggregation of a host of measures, such as lighting, new insulation, and other energy efficiency programs, each of which has its own costs and potential. Each new generation of building in principle presents the opportunity to pursue the entire range of measures. Thus, the supply curve represents perennial increments of new opportunity available in the period, unaffected by prior conservation activity.
- The *decision* about how much energy conservation to pursue is independent of prior decisions about other lost opportunities. That is, cost effectiveness depends only on prevailing prices for electricity, not on prior conservation actions.
- Any period costs and energy savings are *accrued*. Costs and energy savings associated with period activity add to those already obtained to arrive at the total current cost burden and energy for the period. The total cost and energy from lost-opportunity conservation in a period is therefore the ***cumulative*** period activity cost and energy up to and including that period. Clearly, we would not assume that the aggregate of these would be non-decreasing as we go forward. Note that accumulating cost relies on the choice to use levelized costs; if the model had used cash flow instead, this would not be the case.
- It is reasonable to assume that the supply curve from which these energy saving measures remains unchanged from period to period. The only exception to this last observation is for changes in the overall potential for lost opportunity conservation. During a period of economic downturn, for example, loads may become depressed and the number of buildings -- and consequently the amount of lost opportunity conservation -- would diminish.

The model obtains the costs for lost-opportunity conservation from the supply curve in particular fashion. Now, clearly a contractor does not pay the same for energy savings from all sources. A contractor does not pay the same for the energy savings from compact fluorescent lights as he or she would for high-efficiency heating. Instead, the amount paid for energy savings from compact fluorescent lights is their market price. This rather obvious observation has implications for how supply curves will yield costs, as we will see in the following example.

Suppose that the prevailing market price for energy is \$60/MWh. At this price, given the supply curve in Figure L-28, the annual cost-effective level of conservation would be 70

MWa. If this were the supply curve of some commodity in a market, the cost of the purchase of this commodity would be $36,792,000, i.e., the 613,200 MWh in a year times the market-clearing price of $60/MWh.

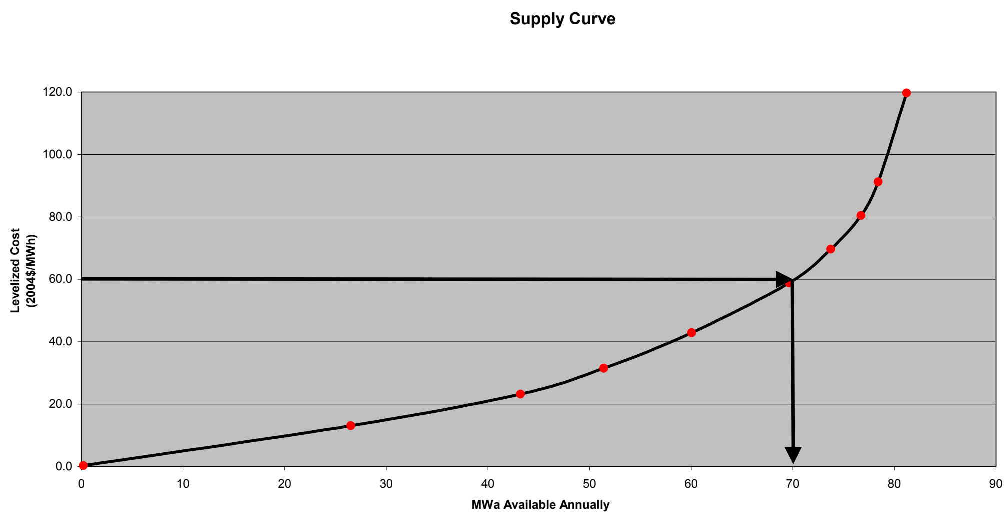


Figure L-28: Supply Curve

For the cost of conservation from a supply curve representing a host of distinct measures, however, the total cost associated with the conservation is the accumulated cost of each measure along the supply curve below the cost-effectiveness price, as illustrated in Figure L-29. This cost is much smaller, $13,467,624, although the value of the energy would still be $36,792,000, as estimated before. We will borrow the economist's term for this

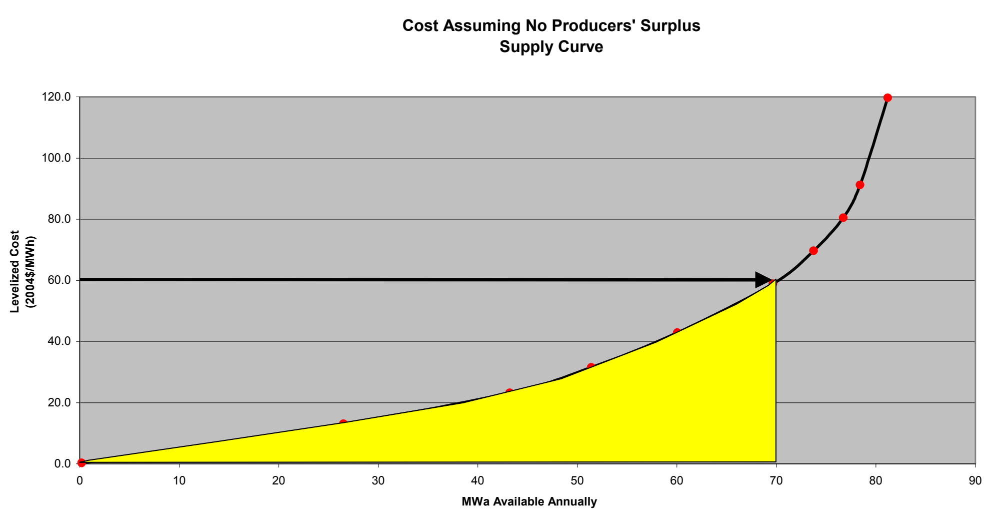


Figure L-29: Costs Associated with Supply Curve

cost, the "cost, assuming no producers surplus." This is how the model computes the costs of conservation.

Contrast lost-opportunity conservation with discretionary conservation measures. Discretionary conservation measures are the second example of the application of supply curves in the portfolio model. Discretionary conservation measures are those that can be performed cost effectively at any time. Examples of discretionary conservation include changing out low efficiency lighting for high-efficiency lighting in existing buildings. The Council's definition of discretionary conservation does not include new discretionary conservation that will arise from improvements in technology or opportunities for cost effective retrofitting in new construction. Instead, assessment of discretionary conservation is a snapshot in time representing conservation that exists at that point in time. It is therefore a very conservative estimate of discretionary conservation available in the future.

As with lost opportunity conservation, we would not assume that accumulated costs and energy savings could diminish as we go forward. The energy and costs reported in a period are the ***cumulative*** amounts due to decisions in all prior periods. Also, the costs associated with discretionary conservation are derived from the supply curve in the same way as were those for lost opportunity conservation. That is, they are costs assuming no producers' surplus. In several other regards, however, discretionary conservation differs from lost opportunity conservation.

- The conservation that is available in each period is directly dependent on prior conservation activity. A measure can be implemented only once, and once implemented is no longer available as a future development option.
- A single, unchanging supply curve represents total conservation available throughout the study period. Only as market prices rise above prior "high water marks" does additional conservation become cost effective.
- The highest prior cost-effectiveness level therefore determines both the energy and cost of total conservation available in that period. In the case of discretionary conservation, the costs and energy in Figure L-29 would represent the cumulative cost and energy due to all the prior conservation action taken up to the present, not the period's addition of cost and energy as in the case with lost-opportunity conservation.

The third and final example is that of price responsive hydrogeneration. When system operators are making decisions about how much water to send through the dams, they must consider several factors. The amount of water that they have at their disposal is limited. Moreover, while they may allow temporary excursions from target forebay levels, they are responsible for assuring that the ending levels are on target. Given these constraints, they may use that water now -- possibly drawing down forebay levels -- to generate electric power, which they will sell on the market at the prevailing market price, or they may withhold the water until market prices are higher. Operators do not have perfect foresight about future prices. Experience with daily and weekly variation in prices and with the effect that other events have on electricity prices, however, help shape their expectations.

Even assuming perfect foresight, optimizing the economic value of this storage is challenging. There are, for example, minimum and maximum constraints on generation and stream flow. The portfolio model does not attempt any such optimization. Instead, the portfolio model logic borrows from that of earlier Council models, Genesys and the SAM model. In these models, the decision to draw down or withhold hydrogeneration is based on the comparison of prevailing market prices to prices associated with various blocks out of regional, thermal generation. The assumption is that if storage is drawn down below an equilibrium level, then some form of thermal generation will be needed to restore the hydrogeneration system to its equilibrium state. The further down the hydro system is drawn, the more expensive the replacement energy. Similarly, if current storage is in surplus, the associated energy is inexpensive.[19]

The supply curve associated with price responsive hydrogeneration, therefore, is a reversible supply curve. At the beginning of the study, the supply curve will start out with an equilibrium state, that is, a starting market price and energy level. If market prices rise above the starting price, the market prices is compared to the starting price and energy is made available up to the higher market price. Figure L-30 illustrates the situation where the starting price was $35/MWh and current market price is $58/MWh. This causes the hydro supply curve to yield 10 MW-mo of energy. The cost of this energy is the increment of cost, assuming no producers' surplus, incurred since the prior period, illustrated by the white area in the figure.

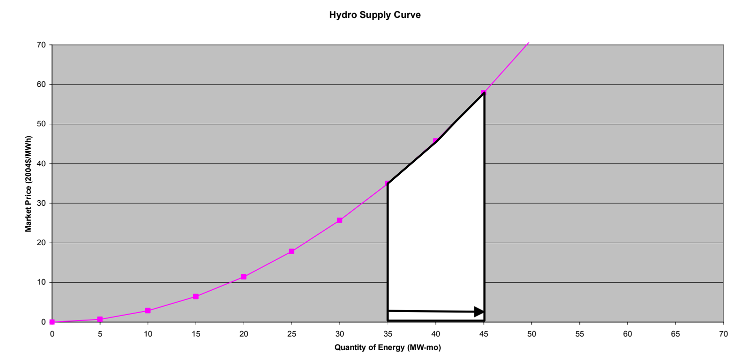


Figure L-30: Price-Responsive Hydro

[19] The cost typically is not assumed negative, because some surplus capability always has value as insurance against contingencies such as plant outages. The exception is if the surplus storage would interfere with the flood control responsibilities of the hydrogeneration project.

The gross value of this energy is just the market price times the energy provided, illustrated (with suitable scaling for hours) by the rectangle in Figure L-31. The net value of this energy, therefore is the difference between gross value and cost, illustrated by the remaining triangle in Figure L-32.

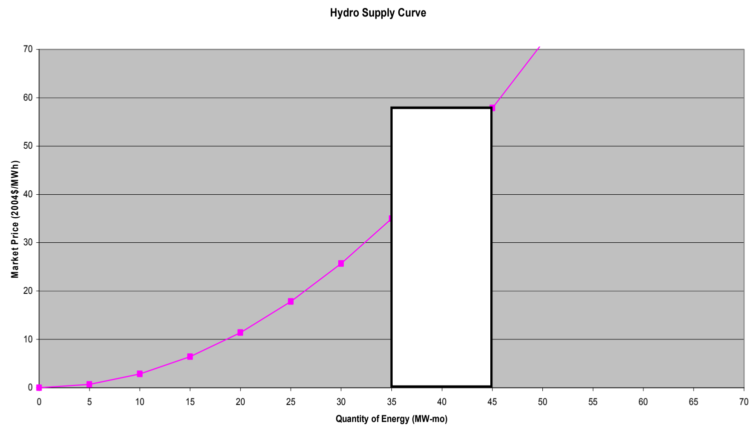


Figure L-31: Gross Value of Energy

In the next period, if the market price is higher than the prior period, an increment of energy corresponding to the difference of two prices will be made available. If the market price is lower than the prior period, the operators will effectively "refill" hydroelectric storage. If the system is refilling, the role of market price and supply curve cost reverse. The market price determines cost, not benefit, and the supply curve determines benefit, not cost. This results in the net value illustrated by the triangle in Figure L-33. When refilling, the hydro system puts load on the energy balance. The load will be equivalent to the energy corresponding to the difference of those two prices.

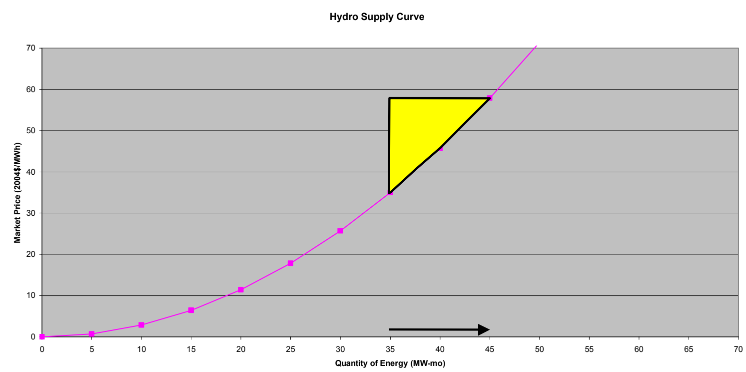


Figure L-32: Net Value of Energy, Increasing Price

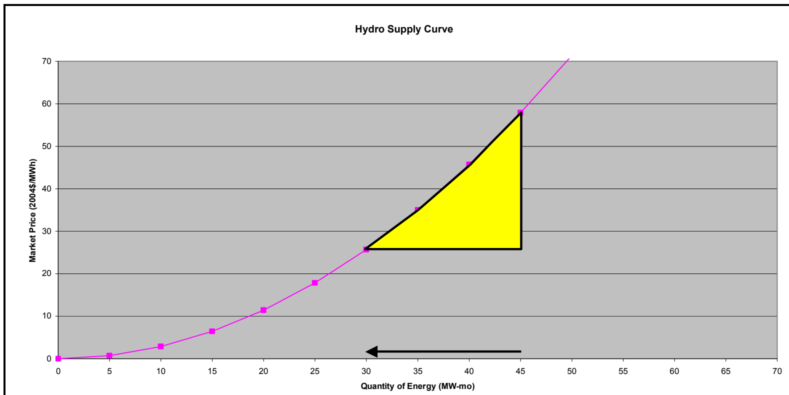


Figure L-33: Net Value of Energy, Decreasing Price

The supply curve for price-responsive hydro resembles that of discretionary conservation in that the cost and energy available does depend on decisions made in prior periods. It differs from discretionary conservation, however, in that the supply curve is reversible, and the cost and energy in each period is incremental rather than cumulative. Whereas discretionary conservation energy is all energy along the supply curve up to the cost-effectiveness price, price-responsive hydrogeneration energy is due to electricity market price differences between this period and the prior period. Costs for price-responsive hydrogeneration also depend on these price differences.

Note the following oddity about price responsive hydrogeneration value. The value of the energy is of course determined by market price, but it changes are gradual the market price is very close to the shadow price for that energy reflected in the supply curve. Consequently, as changes are more gradual and smaller the net value of the energy approaches zero. If, on the other hand, changes are abrupt, there is a positive value associated with the hydrogeneration because the gross value is determined by the market price all the cost is determined by the supply curve assuming no producers surplus. If there is an abrupt decrease in market price, however, the cost of the load is smaller than the value associated with restoring the energy to the hydro system. Thus there is a net positive gain or value to the storage, but the size of the gain depends on the size and frequency of adjustments.

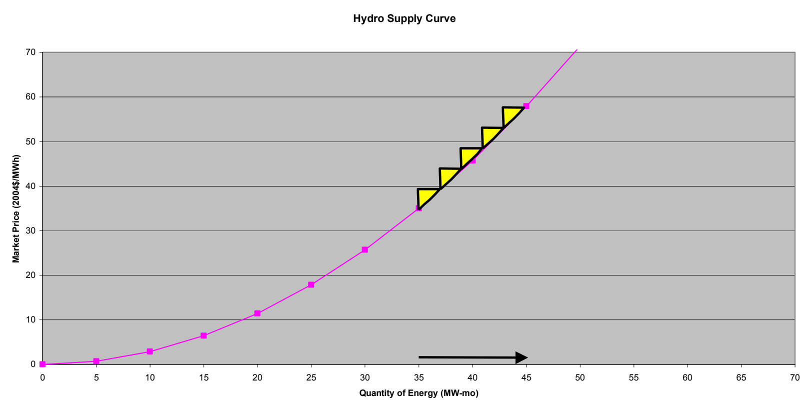


Figure L-34: Value as a Function of Adjustment Frequency

Because the value of the price-responsive hydro depends in such a sensitive fashion on the frequency and step-size of adjusts to market price, and because it seemed reasonable the operators made adjustments relatively frequently, the decision was made to ignore the value of the price responsive hydrogeneration effectively assuming that changes are made continuously and are small. This does not mean, however, that the hydro energy does not have value to the system. The primary source of value instead is due to price moderation. As explained in the section "The Market and Export/Import Constraints," on page L-50, the ability of price-responsive hydro to rebalance system energy when the region is close to import and export limits prevents market price excursions. Preventing these excursions has significant value to the system.

Before examining the supply curve logic, consider the similarities and differences among the three applications of supply curves provided above. First, the supply curve may represent period potential, or they may represent the total amount of energy available over the study. An example of the former is lost-opportunity conservation; examples of the latter are discretionary conservation and hydro generation. While period curves may change from period to period, the fixed supply curves obviously can not. Second, supply curves may be reversible, as in the case of hydro generation, or non-reversible, as in the case of both types of conservation. To facilitate discussion, Figure L-35 presents these options as a grid. Lost opportunity conservation would fall in the upper left-hand corner, discretionary (non-lost opportunity) conservation would fall into the lower left-hand corner, and price-responsive hydro would fall into the lower right-hand corner.

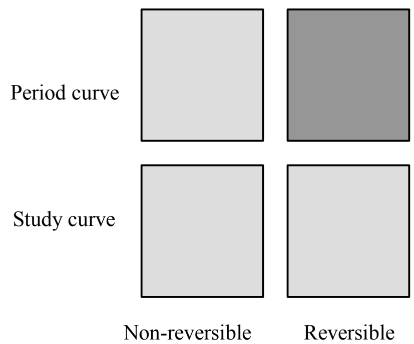


Figure L-35: Supply Curve Options

One question that arises is, "Does it makes sense to speak of a reversible, period supply curve?" This case would lie in the upper right-hand corner, which is slightly darker in Figure L-35. For this to be feasible, circumstances must arise where the supply curves for adjacent periods have at least one point in common, the access point. Because period curve can potentially change from period to period, however, this common point would typically change each time the curves are used. Because of the complexity of this situation, and because no physical systems come to mind which might require this representation, it is excluded from further consideration.

There is one more aspect of supply curves that Figure L-35 does not address. The energy and cost returned in a given period may either be the cumulative amount due to all changes in prior cost and energy, or may be the increment of cost and energy only due to changes in that period. In the former case, the incremental change adds to the cost and energy incurred up to the current period. Figure L-36 illustrates this additional dimension. The combination representing a reversible, varying supply curve is missing from this illustration, consistent with the exclusion described in the preceding paragraph. The three kinds of supply curves used in the regional model now correspond to the lighter-colored boxes in this figure. Price-responsive hydro now falls in the row of boxes associated with incremental costs and energy, behind the row of boxes associated with cumulative cost and energy.

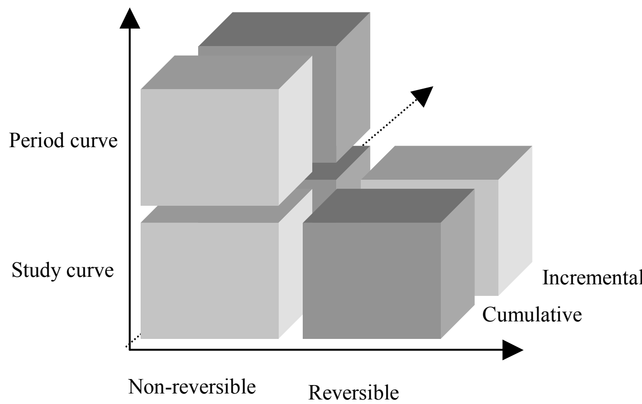


Figure L-36: Aspects of the Supply Curve

This concludes the discussion of supply curve concepts requisite to understanding the computer model. The subsequent material describes the use of functions that perform the tasks of computing the energy and cost.

Conservation

Before each game, the worksheet model must initialize several arrays of data that the supply curve worksheet function accesses. These arrays contain a description of the supply curve in each period and look-up values for cost. The description of the supply curve appears in {row 376}. The supply curve changes only if there is a new entry in the column corresponding to the period of interest. For lost opportunity conservation, the supply curve changes several times, including during this period. (See {AQ377}.) The supply curve syntax is

0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102,

which represents a piece-wise linear supply curve defined by five points. The points are separated by the special characters "@+". The second point, for example, is (5.075,15.5), where the first coordinate is the energy in MW (Q is 5.075 MW), and the second coordinate is the price in \$/MWh (P is \$15.5/MWh in 2004\$). Because this supply curve represents quarterly increments, each Q value is one-fourth the annual capability. The description of the data development for these supply curves appears below, in the subsection "Resource Implementation and Data," of the section "Resource Implementation and Data," on page L-92.

Other information loaded at the beginning of each game appears in the range {F376: P377}. Column F contains the "curve type." The curve type is an integer -- 0, 1, or 2 -- representing to which category in Figure L-35 the curve belongs. (See Figure L-37.) Column G contains the integer 0 or 1, denoting the incremental or cumulative treatment of energy and cost, respectively.

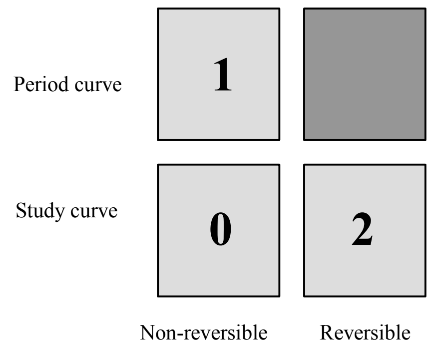


Figure L-37: Curve Type

All supply curves extrapolate indefinitely in both directions unless terminated by endpoints. Upper and lower prices define the endpoints. Column H contains the upper price; column I contains the lower price. Arbitrarily small and large numbers define unbounded curves.

Changes in energy from period to period may be constrained to a maximum rate. The maximum rate of change, or "ramp rate", is specified in column J. If no constraint is intended, use an arbitrarily large value.

Columns K through O specify initial conditions for cumulative and incremental cost and energy. These initial conditions play an important role in specifying the starting place for price-responsive Hydro. For both kinds of conservation, the initial values are zero.

The last parameter is an index that specifies to which supply curve this data pertains. This index appears in column P. The supply curve workbook function use this index to determine which portion of data arrays to access and modify.

The first row in the period containing an example of the worksheet supply curve function is {row 377}, where the on-peak energy for lost opportunity conservation is estimated. The formula in cell {AQ377} is

```
=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)
```

The first constant is the number of hours on peak. The second, 1.402, is the on-peak weight for lost opportunity conservation. Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection “Supply Curves” of the section “Resource Implementation and Data,” below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of this weighting factor appears in that section.

To understand the last factor, it is necessary to follow the parameters in the call to the function, defined as follows

```
Function sfSupplyCurve(ByVal sPrice As Single, ByVal lCurve As Long, ByVal lPeriod As Long,
    ByVal dummy As Single, Optional ByVal sProportion As Single = 1) As Single

        ================================
        Takes:
        sPrice -   Price in $/MWh
        lCurve -   index to unique supply curve
        lPeriod -  0-based index into period
        dummy  -   Forces the order of calculation
        sProportion - multiplier for Lost-Opportunity supply curves only
        ================================
        Returns:
        A single with the amount supplied, MW
```

The first parameter in the function call in cell {AQ377} is AP$233+$R$375, the price used to access the supply curve. This sum points to a decision criterion in the previous period (AP$233) and a constant over which the optimizer has control ($R$375). The optimizer can adjust this latter constant, which is a premium over decision criterion price, if doing so reduces cost or risk. A brief description of this appears in Chapter 6.

This is the first time we have encountered a situation where a function or formula accesses a price or decision criterion in a prior period to determine response. The complete discussion of this practice is in the section “Concept Of Causality,” below, and description of the decision criterion is in the appropriate subsection of the section “Decision Criteria.” Briefly, however, the decision criterion for lost opportunity conservation is a non-decreasing, average market price over five years. This is intended to reflect the fact that decisions to modify such programs, such as building code changes, usually take awhile, but much of the measure gets institutionalized into standards and building codes. It is much less typical to make such decisions based on *current* market prices.

The second and third parameters in the function call in cell {AQ377}, $P377 and AP$46, point to the curve 0-based index and the prior period’s 0-based index, respectively. That is, the first supply curve has index 0, the second curve has index 1, and so forth, and these curves may appear in any order in the worksheet. Similarly, the first period (Sept-Nov 2003) has index 0, the second period (Dec 2003-Feb 2004) has index 1, and so forth. These are simply used to organize data in an array that holds data for all supply curves and all periods.

The fourth parameter in the function call in cell {AQ377}, AP377, points to the supply curve formula in the preceding period. This is a dummy reference that forces Excel to calculate the prior period’s supply curve value *beforehand*. An internal, cell-dependency tree specifies the order of formula evaluation in a worksheet. This tree assures that when calculation takes place, only those cells that have changed -- and any cells that depend on those cells -- recalculate. This saves recalculation time, but renders the order of cell recalculation and function call unpredictable. Because conservation in one period depends directly on conservation in prior periods, calculations and supply curve function calls must occur in strict chronological order. The dummy reference assures chronological firing of function calls.

The fifth parameter in the function call in cell {AQ377}, AP240, scales the quantity of the lost-opportunity supply curve. As mentioned earlier, such things as downturns in building construction affect lost-opportunity conservation. To capture this, the model uses percentage change in load as a surrogate for these effects. If loads increase one percent relative to the benchmark load, lost-opportunity supply potential increases one percent at all price levels. Clearly, the *recently past* change in load affects the potential for lost-opportunity conservation.

The period cost of lost opportunity conservation lies in cell {AQ378}. The supply curve function sfSupplyCurve computes all costs when it computes energy. A simple function in {AQ378} simply retrieves that information from data arrays. The content of {AQ378} is

=(sfCostCurve(AQ377,$P377,AP$46)*1152*1.402-AQ$207*AQ377)/1000000

This formula is valuing the on-peak conservation energy in the market and converting the value to millions of dollars. As elsewhere, cost is positive and value is negative, so this formula computes cost less gross value, rather than gross value less cost. There are two terms in the numerator. The first term is

sfCostCurve(AQ377,$P377,AP$46)*1152*1.402

which represents the cost of the conservation in real levelized dollars for the period. (See page L-16, ff. for a discussion of the use of real levelized dollars.) The supply curve function has already multiplied the $/MWh value by the MW obtained from the supply curve, yielding real levelized $/hr which sfCostCurve(AQ377,$P377,AP$46) reports. Again, the real levelized $/hr is multiplied by the number of hours in the standard on-peak period and by the weighting factor.

The function sfCostCurve has the following syntax:

```
Function: sfCostCurve(ByVal dummy As Single, ByVal lCurve As Long, ByVal lPeriod As
        Long) As Single

Purpose:  Retrieve costs that were calculated by sfSupplyCurve

==============================
Takes:
dummy  -   Used only to re-trigger the fetch of cost information; Excel
           will call this function after the sfSupplyCurve function
           has been updated
lCurve -   Unique integer identifying curve
lPeriod-   Unique integer identifying period
```

```
Returns:
   A single with cost (value) in $/hour real.  The value already reflects
   the rate of energy supplied
```

The first parameter references the supply curve function, to assume that function has been updated before attempting to access the associated costs. The second and third parameters merely access the 0-based period and supply curve indices to permit the function to locate the data in the memory arrays.

The second term in the numerator is AQ$207*AQ377. This is the gross value of the energy. The cell {AQ$207} contains the relevant on-peak market price for electricity in the period; the cell {AQ377} is the on-peak conservation energy, which has already been adjusted by on-peak hours and weighting.

Similar calculations exist for off-peak energy and cost. The energy calculation in cell {AQ741} is

=AQ377*864*0.465/1152/1.402

which determines the off-peak energy contribution. The MWh off-peak is the product of off-peak hours (864) and weighting (0.465) applied to the MW rate. The MW rate, in turn, is the MWh on peak after removing the on-peak hours (1152) and weighting (1.402) factors. The calculation of costs off peak is the same as on-peak, with appropriate substitutions for off-peak hours and weighting:

=(sfCostCurve(AQ741,$P741,AP$46)*864*0.465-AQ$219*AQ741)/1000000

The allocation of gross conservation costs on and off peak is a bit of a fiction, but reader should be able to convince himself the distribution does not matter as long as the total gross cost is correct. The benefit, due to allocation of energy on- and off-peak, however, is critical.

Discretionary conservation energy and cost calculation is similar to lost-opportunity calculation. Before the game, the workbook reads a single supply curve from cell {R385}. It reads other information from the range {F385:P386}. Most of the parameters in this range are identical to those for lost-opportunity conservation. The two exceptions are the choice of "curve type," cell {F386}, and the ramp rate, cell {J386}. The curve type conforms to the type of conservation, as illustrated in Figure L-37. The ramp rate, expressed in MW per quarter, is a constraint that limits the amount of conservation that can be added in each quarter. This constraint is essential, because of the low cost of discretionary conservation programs. If the supply of energy were not constrained, almost half of the energy available in the curve, roughly 1500 MW, would be implemented in a single quarter. Clearly this is not realistic. For several reasons, including cash flow constraints, rate impact constraints, and limits of available resources for pursuing such programs, the model employs this ramp rate.

Price-Responsive Hydro

As for conservation, the worksheet model initializes the supply curve-worksheet function for price-responsive hydro before any games. The description of the supply curve for hydro is fixed throughout the study and appears in cell {R528}:

-250,5@+0,30@+250,60

The supply curve syntax is just as for conservation. As with lost-opportunity conservation, this supply curve represents quarterly increments. In this case, the supply curve has a zero quantity at $30/MWh, but this is somewhat arbitrary, because only differences in quantities on the supply curve get used. The supply curve, in fact, stops at $5/MWh and $60/MWh, as explained below. This means the total amount of energy available from the curve, obtained by a swing in market price from $5/MWh to $60/MWh, is 500MW, or 1,008 GWh (500MW * 2014 hours per standard quarter). Compared to the hydroflexibility limit for the PNW hydro system, about 7200 GWh, this is a small value, as it should be.

The other data loaded before simulation, in range {F528:P529}, differs significantly from what the model has for conservation. As explained earlier in this section, the curve type and treatment both differ from what we use for conservation. This combination of values assures the model uses a reversible supply curve and the user-defined function (UDF) returns only the incremental energy and associated increment cost between the current and the immediately prior year.

Upper and lower price limits (cells {H259} and {I259}, respectively) reflect the assumption that the amount of energy available for shifting is constrained. The values here match the endpoint values of the supply curve, although that is not a constraint of the model.

The initial price (cell {O259}) is set to $30/MWh, the midpoint of the supply curve. Recall that the energy provided by the supply curve is determined by comparing the period electricity price against a baseline, the price in the prior period. In the first period, however, there is no prior period, so an "initial price" must be specified. That is the purpose of this parameter. Its value is somewhat arbitrary, but it has been set to the rough, average cost of electricity at the beginning of the study. After several periods, this value of this initial price probably becomes immaterial to energy calculations.

Note that in cell {AQ529}, the price for accessing the supply curve ({AQ$224}) is the *current* price, not the price or criterion function value in a prior period:

```
=sfSupplyCurve(AQ$224,$P529,AP$46,AP529)*1152
```

This is a departure from the case for conservation. This is consistent with how we expect that price-responsive hydro would behave. Any generation or refill would be to avoid or take advantage of *current* market prices.

Conventional Hydro

Hydrogeneration is a key uncertainty, due to its reliance on variable stream flows and weather. For this reason, the discussion of the user-defined function (UDF) that provides these energy values appears in Appendix P, instead of here. Appropriate for discussion here, however, is how the MWa provided by the hydro UDF influences the costs and energies in the portfolio model.

As described in Appendix P, the UDF returns east-side and west-side generation separately. The west side, on-peak hydrogeneration formula in cell {AQ437} is

```
=$R$136*$AQ$36
```

The first term in this product points to the constant 1.0. This is a vestige of logic in Olivia that provides the user the capability to scale hydrogeneration. The second term points to a cell, {$AQ$36}, containing simple conversion from the MWa returned by the UDF, {AQ33}, to MWh:

=AQ33*1152

Finally, the cost is the inverse of the value of the hydrogeneration in millions of dollars. Because the model assumes no variable cost, the value is just the MWh times the market price in $/MWh from cell {$AQ$204}:

= -$AQ$36*$AQ$204/1000000

Identical calculations exist for east-side hydrogeneration, rows {594} and {595}, and for off-peak generation on the west side, rows {798} and {799}, and on the east side, rows {951} and {952}.

The Market and Export/Import Constraints

The portfolio model assumes that dispatchable resources respond to market prices for electricity.[20] When a power system is unconstrained by transmission or other import/export limitations, one typically does not have to worry about whether a given market price is somehow infeasible. This situation may exist for individual utilities that consider themselves price takers in a relatively deep market for electricity. Higher prices simply mean more generators will run.

The region as a whole, however, is different. If a lot of generation is added to the region and exports are constraining, prices must fall to balance demand. Price is no longer an independent variable.

A regional model that incorporates market price uncertainty lies somewhere between these extremes. Electricity prices are neither completely independent nor completely dependent of other variables. As the reader will see, at least one other variable must typically play the role of a "slack variable," so that the pair is dependent. In the Council's portfolio model, the slack variable is net exports.

When Monte Carlo simulation selects an electricity price for the regional model, it may not be feasible. If the price is high, the resulting generation, after exports, may be surplus to requirements. Energy must be conserved, however: energy consumed must equal energy produced. In this example, the price must be adjusted downward until the situation becomes feasible. The situation will be feasible when generation equals loads plus exports. Similarly, if the price is high, the resulting generation, after imports, may be inadequate for our requirements. The price must be adjusted upward.

[20] Strictly speaking, the assumption is that dispatchable resources respond to some explicit, widely visible signal of generation value. In the world before price deregulation, the measure of merit was "system lambda," which indicated the variable cost of generation on the system. Regulators among others sometimes refer to this concept as the "avoided cost." Economists refer to this kind of value as a "shadow price." It simply represents a means for assigning value to alternative means to meeting system requirements or the requirements of others. In describing the portfolio model, all of the arguments work if one substitutes these identical concepts for that of deregulated market price for electricity.

RRP algorithm

The Resource-Responsive Price (RRP) algorithm in the model finds a price that balances the system's energy. It does this by iteratively adjusting the price. Figure L-38 illustrates this process in the case where prices start out too low and upward adjustment is necessary.

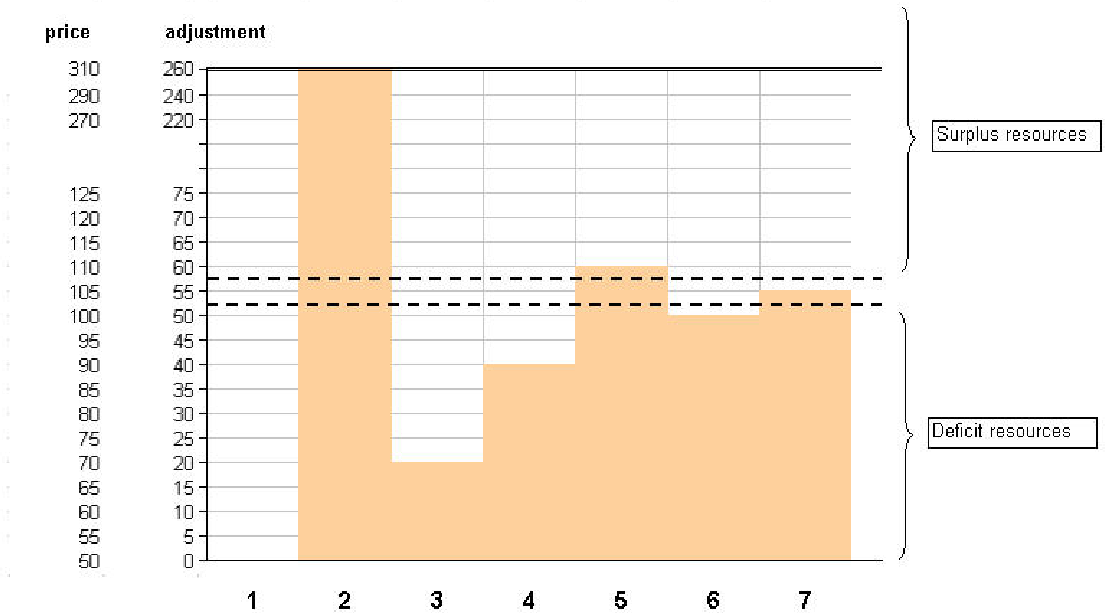


Figure L-38: RRP Algorithm Finds Price Iteratively

In this example, a random draw of electricity price yields $50/MWh. At this price, however, the system does not have enough generation to meet its load, even after all possible imports. The vertical axis is the price adjustment, from zero to $260/MWh. Next to the vertical axis are values representing the electricity price. Before any adjustment, the electricity price is $50 a megawatt hour. The difference between the two columns is the initial starting place of $50 a megawatt hour. Along the horizontal axis are the steps in the iteration process. At step number one, there is no adjustment. There are three horizontal lines on this graph. The first line, level with an adjustment of $260 per megawatt hour, represents the maximum possible adjustment. This corresponds to electricity market price of $310. As we will see shortly, this maximum price is the user-selected value. The second line, level with an adjustment of about $57 per megawatt hour, represents the lower limit of price adjustments that would produce resource generation surplus to our requirement. Above this price, resources would generate an amount of electricity that would exceed our ability to export energy surplus to our requirements. The third line, level with an adjustment of about $52 per megawatt hour, represents the upper limit of price adjustments that would result in generation inadequate for our system. Below this price, resources would not generate sufficient electricity to meet our requirements, even after importing the maximum possible energy. The distance between these latter to lines is quite small, atypical of situations that arise. The situation, however, will help us illustrate how the RRP algorithm works.

In step one, the worksheet determines that generation is deficit to our requirements. (The value that determines whether the system is surplus or deficit during the on-peak subperiod lies in a row {678}. A complete description of the functioning of the workbook and the formulas appears later in this section.) In step two, the algorithm tries the largest possible price adjustment. If the system is still deficit resources, the algorithm stops and uses this largest price. If the system is no longer deficit, the algorithm proceeds to step three. In steps three through five, the adjustment is moved upward by equal increments until the system is no longer deficit. If the system were in balance at this point, the algorithm would stop and use that adjustment. In step five, however, the adjustment was large enough that the system is now energy surplus. The algorithm now changes search strategy. Instead of using even steps, the algorithm uses a binary search strategy. In step six, the algorithm takes the value halfway between those in steps four and five. In step six, however, the resulting adjustment again overshoots the region where the system would be balanced. The algorithm then tries an adjustment halfway between those in steps five and six. The resulting price adjustment now balances the system (step seven), and the algorithm stops. This final adjustment is used.

The increment size used in steps three through five is a pseudo random value. It is chosen to be relatively small compared to the price. The algorithm uses the approach of equal size to increments at the beginning of the search process in order to arrive at a final adjustment that is only slightly above the largest adjustment that would result in deficit resources. Experience has shown us that using a binary search throughout this process produces a price adjustment close to the middle of the vertical scale in a very large number of instances. This in turn produces unnatural price probability distributions. Using even increments early in the search process brings us closer to the minimum adjustment that would balance the system, and that turns out to be a much more variable value.

If the system had started out to surplus instead of deficit, an identical search process would be used except that the algorithm would use negative adjustments to price. Instead of the maximum adjustment, the algorithm would use the starting price as the maximum negative adjustment.

To relate these observations back to the workbook, first consider Figure L-6. Recall that there are three regions in the workbook where distinct kinds of calculations are made. At the top of the workbook are the cells associated with futures. These are calculated only once, at the beginning of each game. Below this lie the twilight zone (TLZ) rows, in which each column will be updated iteratively whenever a subperiod's calculations update. (The TLZ is in fact defined by the Parameter section at the bottom of the worksheet.[21]) At the bottom are the rows in which the RRP algorithm iterates to a

[21] In range {Q1328:R1370} (range name, "Parameters"), there appear a list of variables that control the operation of the workbook. The top of the Twilight Zone is determined by the row number, 203, associated

feasible price. There is one set of rows for on-peak calculations and another for off-peak calculations. We are concerned with those rows in which the RRP iterates.

Consider the operation of the algorithm on on-peak prices. The relevant range of cells in the workbook is {AQ215:AQ678}. The algorithm starts with a zero adjustment in cell {AQ215}. The algorithm, which resides in a VBA module, modifies the value of this cell. This adjustment is then added to the on-peak price for the Eastern region in cell {AQ216}. The on-peak price for the Western region, in cell AQ219, is a simple percentage increase over the Eastern region price. This percentage increase represents transmission losses and wheeling costs. The electricity price in cell AQ216 will be then used by all resources in the Eastern region.

The net on-peak requirement for the system is calculated in cell AQ676. This is the on-peak load, including DSI load, less all generation.

=AQ322+AQ328-AQ339-AQ349-AQ359-AQ367-AQ377-AQ386-AQ397-AQ407-AQ417-AQ428-AQ437-AQ460-AQ474-AQ488-AQ499-AQ511-AQ521-AQ529-AQ538-AQ545-AQ555-AQ565-AQ575-AQ586-AQ594-AQ604-AQ614-AQ625-AQ635-AQ645-AQ655-AQ665

The net on-peak requirement met through imports is calculated in cell AQ677. This is where we see the adjustment for contracts, through {AQ367}. That is, if there is imported, contract energy in this period, an adjustment to the export capability is made for counter-scheduling potential.

=MIN(1152*6000-AQ367,MAX(-1152*6000-AQ367,AQ676))

The portion MAX(-1152*6000-AQ367,AQ676) limits exports to 6000 MW, before adjustment for contracts; the rest limits imports similarly.**5** The difference between the net on-peak requirement and the requirement met through imports is calculated in cell AQ678. This amount is the deficit the used by the RRP algorithm.

=AQ676 - AQ677

If system generation were surplus to load requirements, the value in cell AQ676 would be negative. Again the amount of surplus met by exports would appear as a negative value in cell AQ677. The difference between these values would be the net remaining surplus. It would appear as a negative value in cell AQ679, which would signal the RRP algorithm to find a downward price adjustment.

In range {Q1328:R1370} (named "Parameters"), there appear a list of variables that control the operation of the workbook. The variable "dMaxPriceAdj"' a misnomer, has a value of 250. This is actually the maximum price, in $/MWh. The maximum adjustment will be the difference between this value and the original price. Also, when using an iterative technique for solving the problem such as this one, it is useful to know whether a solution is "close enough." The algorithm is searching for a feasible price, so searching

---

with the variable "lTopHeaderRow." The bottom of the Twilight Zone is specified by the row number, 320, associated with the variable “lBottomHeaderRow."

to the penny is neither necessary nor desirable. The variable "dEnergyTol", here set to 100 MWh, is the threshold. That is, if the surplus or deficit is less than 100 MWh, the RRP algorithm will stop refining its adjustment. (The variable "dEnergyTest" in the Parameters list is no longer used.)

The duality between price and import-export capability is now evident in Figure L-38. If there were no import-export capability, only one price would balance the system. Electricity price would be a dependent variable. Conversely if import/export capabilities is unlimited, the price is completely independent. Any price, in principle, is feasible. The RRP algorithm is not necessary.

The relationship between price and import/export capability has additional significance. The import/export capability determines how much random variability is feasible for market price. If there is no import/export capability, there can be no stochastic variation in market price for electricity.

Another issue related to RRP is capacity expansion and portfolio choice. Consider the situation of a single load-serving entity, a price taker in the wholesale electricity market. Assume this entity wants to make resource addition based on economics, as the regional market does. Any resource that makes money on average will of course appear attractive and the optimizer will add it. If resource addition does not depress prices, however, there is no reason to stop there. If one is good, two is better. This process would continue without end. That is, there could be no solution to the capacity expansion problem. If market prices are, on average, lower than the cost of a resource, the optimizer may add that resource if the resource reduces risk, even though it raises cost. It should be evident, however, that without RRP, the issue of portfolio choice depends in a more delicate fashion on the relationship between market price and resource candidate cost. RRP guarantees a reasonable balance because resource addition is limited irrespective of the initial relationship between resource cost and electricity price.

Finally, it may be useful to understand what the effect the RRP has on price for some simple cases. When they were first introduced to this algorithm, the Council staff expected the responsiveness of price to load-resource balance to be constant over the range of balance, perhaps like the resource supply curve in Figure L-39. What they found, instead, was the rather flat response over a significant variation in load-resource balance, as in Figure L-40. Moreover, for difference levels of price, the response was much the same, as shown in Figure L-41. To understand what is going on here, recall from the previous discussion

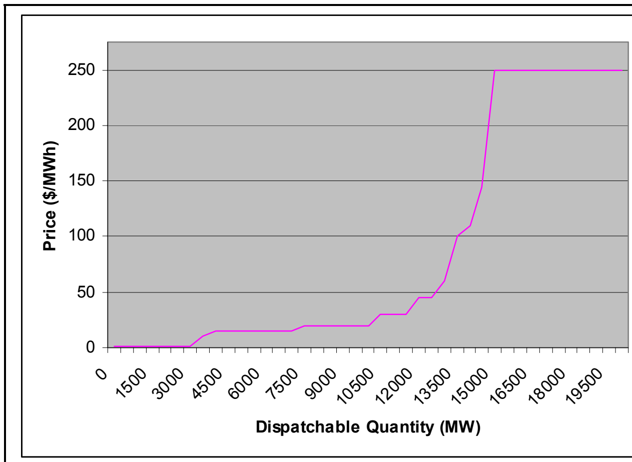


Figure L-39: Dispatchable Resource Supply Curve

that the algorithm does not adjust the price unless it is necessary to do so. This permits whatever stochastic relationship may exist between price and other variables, like load, to express itself without modification in most cases. Under what circumstances and how much the algorithm modifies price is a function of the import/export constraints, the supply curve, and of course, the price and load that are drawn.

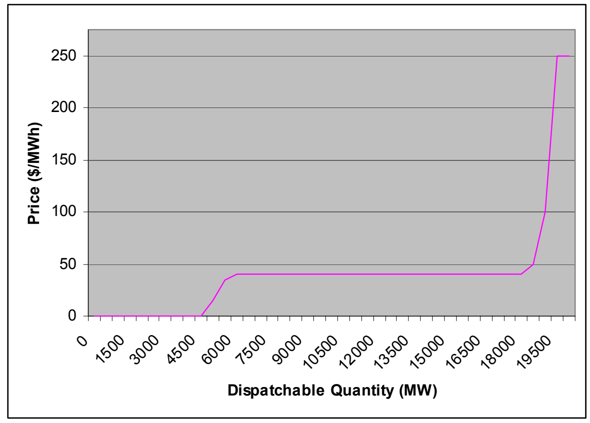


Figure L-40: RRP Response

Before proceeding with the description of price sensitivity to load-resource balance, we make the following simplifying assumptions. In practice, both loads and resources are constantly changing and both contribute to the load-resource balance. In these examples, however, we modify only load. Because only the load-resource balance concerns us, this simplification is not a hindrance to our understanding of the algorithm. The simplification makes these illustrations much easier to follow.

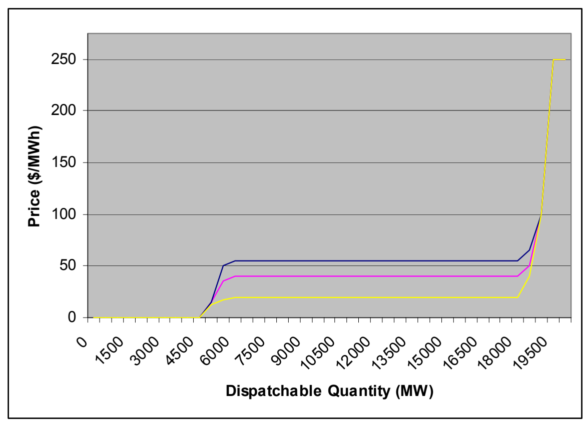


Figure L-41: RRP Response at Various Price Levels

The Monte Carlo simulation initially draws the electricity price and load level independently, although they may be correlated values. For whatever price is drawn, there exists a corresponding load, L_p in Figure L-42, determines by the resource supply curve. Absent imports and exports, this is the only feasible load. The supply curve makes load and price dependent variables. If import-export capability exists, however, there is actually a range of feasible loads that could correspond to this price. Below the load L_p, for example, native load combined with exports could sum to L_p. This is illustrated in Figure L-43. If exports are constrained, however, there is a lower limit on native loads consistent with our price. This lower limit is denoted L^e_p in Figure L-43. Similarly, if imports are constrained there is an upper limit on native loads consistent with our market price. Above this upper limit, it is impossible to import enough energy to bring our net load down to L_p. This upper limit is denoted L^i_p in Figure L-43.

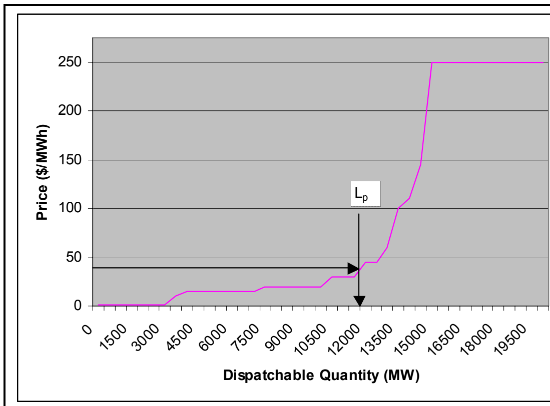


Figure L-42: Load Corresponding to Price

For all native loads between L^e_p and L^i_p, price adjustments are unnecessary. Imports and exports can explain the difference in net load that results in our initial price.

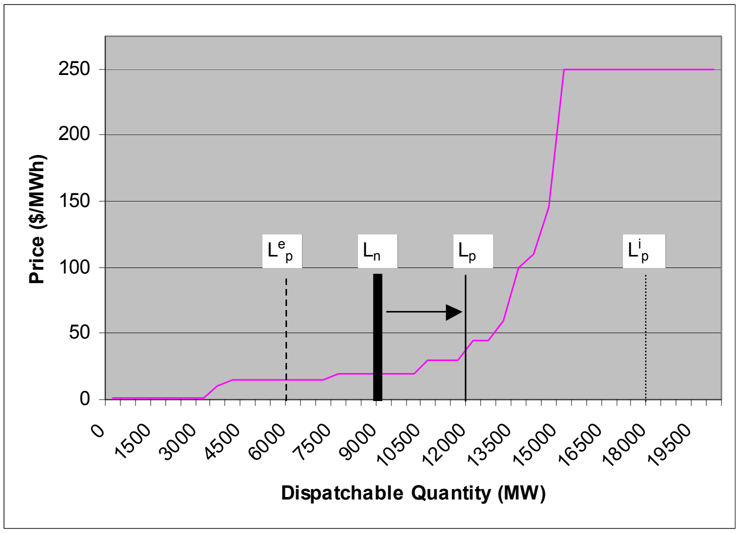


Figure L-43: Native Load

What happens if native load is below L^e_p, however? Clearly, our initial price and the native load are inconsistent, because the necessary amount of energy could not be exported. (See Figure L-44.) The algorithm adjusts the initial price so that the relationship between price and native load is once again consistent. In Figure L-45, the export limit L^e_p is reduced by 4000 MW to L^{*e}_p. This, of course, requires that the load L_p associated with our initial price be reduced by an equivalent amount. The adjusted "price load" L^*_p, together with the supply curve, now defines an adjusted price, illustrated in Figure L-46. In fact, any price between this adjusted price and the price associated with the native load is consistent with the native load.

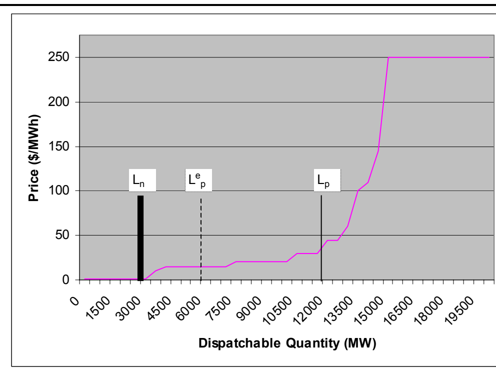


Figure L-44: Native Load below Export Limit

We can now see that over a range of loads corresponding to the sum of import and export constraints, no price adjustment is necessary or made by the algorithm. Outside of this range, however, the algorithm applies an adjustment that resembles the supply curve around the price load. Indeed, if there were no imports or exports the response provided by the RRP algorithm would look identical to the supply curve.

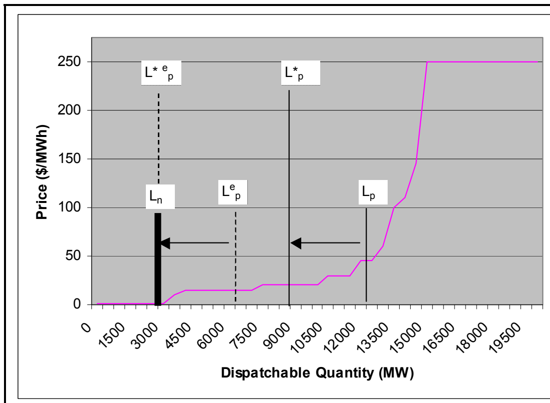


Figure L-45: Adjusting the Price-Load

There is a sense in which the RRP algorithm's response to load-resource balance is sensitive over a larger range of balance values, however. In Figure L-48, the average price as a function of the average load exhibits a more gradual response. The reason for this response is that for any average load level, there is some probability that sample loads will impact the load limits described in Figure L-43. There is greater probability of hitting a limit as the average load approaches the limit, and the effect on the average price increases correspondingly. Thus the relationship between average price average load is more gradual. The relationship for alternative price levels is illustrated in Figure L-47.

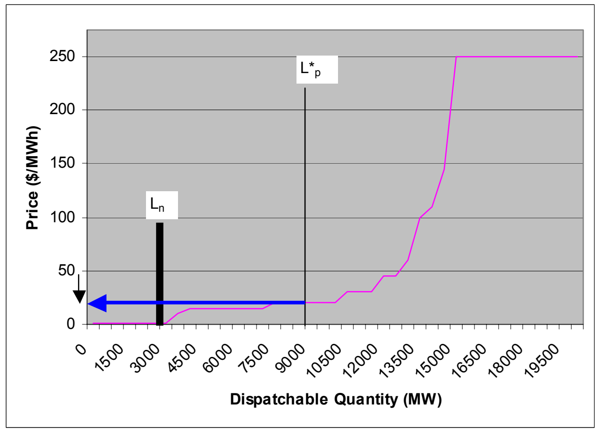


Figure L-46: New Price, After Adjustment

In this section, we have described how the algorithm works to acquire a price that is consistent with native loads, resources, and import and export constraints. This section described the duality between the stochastic behavior of electric market price and levels of imports and exports. Although it is possible to forego with the RRP algorithm when there are no constraints on imports and exports, the users must take special care if they want to add resources to the portfolio. In particular, if market prices are higher than the fully allocated cost of capacity expansion candidates, the optimal solution would be to add increments of the candidate without bound. Finally, we have examined how load-resource balance typically affects the final market price. Market price adjustment is generally insensitive to load-resource balance over a range that corresponds to the import-export limit of the system.

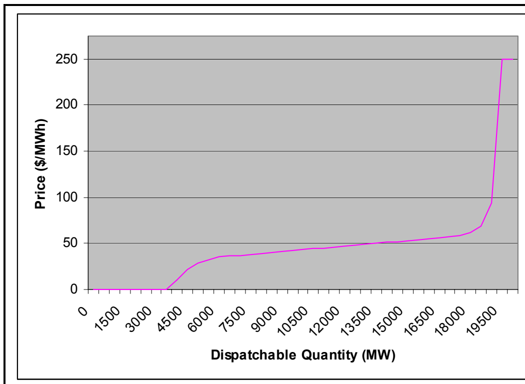


Figure L-48: Average Price vs Average Load

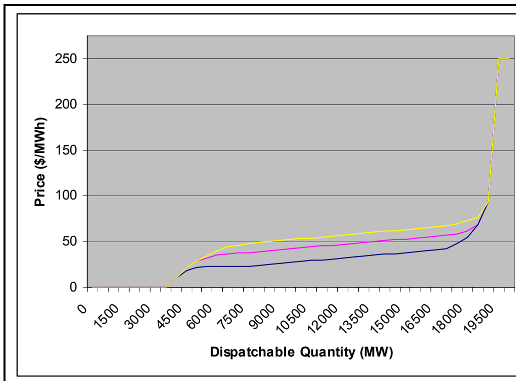


Figure L-47: Alternative Average Prices

This concludes the discussion of variables in quantities that depend only on the current period. Possible exceptions are supply curves for conservation. The amount of energy delivered in a given period can be, and typically is, a function of prices and activity in prior periods. The discussion of supply curves was included in this section nevertheless because the supply curves do not depend the history of a process. Processes such as the startup shutdown of aluminum smelters, on the other hand, depend in a direct fashion on how recently this smelter was shut down and whether it has been down for a significant amount of time. The functions and formulas that rely strongly on the nature of events over time are the subject of the next section.

Multiple Periods

This section addresses processes that rely on memory of past circumstances. They respond not so much according to what is happening now as what has happened in the past. Load elasticity is one example. While the short-term correlation between load and electricity price is typically positive, over the long-term load will decrease if electricity prices remain high for a substantial amount of time. Other examples are the start-up and shutdown of aluminum smelters and the construction of power plants. In the latter case, it may be advantageous to postpone or cancel the construction of a power plant if it appears the plant will be unprofitable or unneeded. This section begins with a discussion of a concept that guides much of the modeling of these behaviors. It then describes how the portfolio model addresses the processes mentioned above.

Concept Of Causality

In the description of the RRP algorithm (page L-51, above), there is a tacit assumption that generation is a continuous function of price. For example, what would the outcome have been if, in step five of Figure L-38, the increase in price had suddenly caused a smelter to shut down? Figure L-49 illustrates one possible outcome. With reduced load, the deficit after imports is reduced, which should make it possible to meet requirements with a lower market price for electricity. The illustration assumes that this affects both the lower price limit for surplus resources and upper price limit for deficit resources to roughly the same degree.

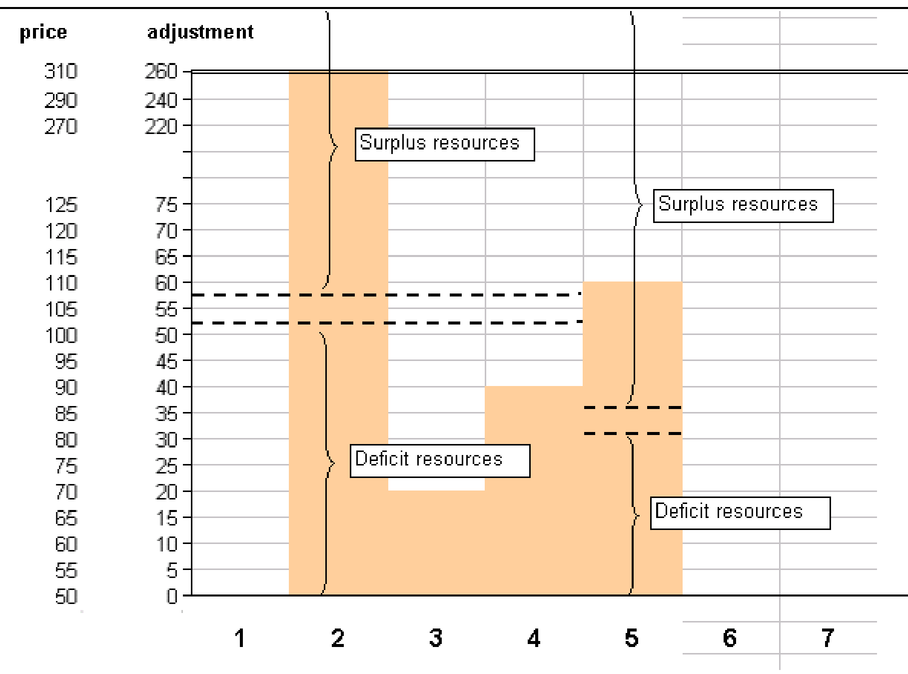


Figure L-49: Discontinuous Load Response to Price

Notice that the reduction in requirement is large enough that the price in step 4 is now too high to satisfy the balance constraints. The algorithm would not work, because there is no obvious way to determine what price would solve the problem, at least not by looking at price and deficit or surplus. In fact, the problem may be more serious than devising a smarter algorithm: there may *be no solution!* It can arise that no price would balance such a system.

To arrange for the iterative algorithm to solve the problem efficiently and avoid situations like this one, response of resources and loads to price must be stable and continuous. One way to assure this behavior is to remove such response from the current period, instead tying the response to past periods where prices have already been determined and fixed.

Thinking about how the primary sources of discontinuous response behave, this makes sense in terms of the accuracy of the model representation. For example, a smelter will not make start-up or shutdown commitments based strictly on current market prices. Instead, they will probably make some forecast about future conditions based on a trend that started at some point in the distant or recent past. It therefore is reasonable to assume that decision makers make such commitments at the beginning of a period and these remain fixed over the period.

This treatment of load or resource response in the portfolio model is an application of the "concept of causality." Actions in the past affect current circumstances, instead of having actions and circumstances occurring simultaneously. Wherever this approach is reasonable to use, it simplifies and speeds the iterative solution of the balance by removing a source of change and, as emphasized above, discontinuous change.

Conservation is an example of where the portfolio model employs a concept of causality, not because its response is discontinuous -- it is not -- but because it makes sense to do so and reduces computational burden. Pointing the supply curve's price to a decision criterion that depends only a on past period fixes the value of conservation in that period. The rather time-consuming computation of conservation takes place only once. Moreover, it makes sense that utilities would deploy conservation in this fashion, paying little or no attention to today's market prices but instead following budgets that may have been adopted the year before.

Load

There are several components to load representation. There is an underlying trend, possible jumps associated with economic cycles, and a seasonal variance. Appendix P describes these. There is also a long-term sensitivity of loads to electricity price, which this section describes. The final calculation of energy and cost appear under the previous section, "Single Period."

Load elasticity changes once each year, because customers base their consumption habits more on annual average prices than seasonal costs. Additionally, retail customers are unlikely to see seasonal variation because of the ratemaking process. The load adjustment for electric price in {AQ321} points to the calculation in {AP321}, where the annual revision takes place. That calculation is

=(1+MAX(-0.002, MIN(0.002,-0.002*(AO225-$Q$224)/$Q$224)))

This formula limits load variation due to price elasticity to 0.2 percent. Some bounding of the elasticity provided better stability. That is, without bounding, the situation can arise where high prices depress loads, which in turn reduce prices, which increases load, and so forth.

The cell {$Q$224} contains the study's starting price for annual average electricity price. This is a cumulative change in load, up to the current period, due to changes in electricity since the beginning of the study.

Council Staff [**6**] chose the value of -0.002 as follows. They estimated an upper limit by starting with a five-year elasticity factor of -0.1 as appropriate for non-DSI loads, where electricity price is a retail rate. Because wholesale prices contribute about half to retail rate variation, an upper limit using wholesale electricity price is about -0.05. Using a single year's change warrants a value of perhaps -0.01. Finally, the stochastic treatment of load uncertainty captures much and perhaps most of the impact of independent influences on load, including some economic effects related to electricity price. A figure of -0.002 seemed an appropriate choice and provided realistic behavior.

DSIs

Aluminum smelters have a cost structure heavily dependent on the price of electricity. With the increases in electricity price during the 2000-2001 energy crisis, the region saw 2000 MW of smelter load disappear. This constitutes 40% of the 5000 MW shift in the resource-load position the region has witnessed since 2001. Capturing the load uncertainty associated with direct service industries (DSIs) such as aluminum smelters is clearly important to the Council's treatment of risk.

Smelter load curtailment is distinct from dispatchable resources and demand response. Whereas dispatchable resources and demand response can curtail within hours, it requires months for a smelter to arrange for startup and shutdown. Although there is a portion of smelter load that can change with short notice, there are typically severe limitations on the amount and use of this load as a curtailment mechanism. Aluminum pot lines have significant thermal inertia, and several hours of interruption will not significantly affect production. However, extended shutdowns or repeated interruptions, without adequate preparation, can be disastrous.

In 1992, Council staff performed analysis of the profitability of each of the seven smelters in the region. Figure L-50 illustrates a typical calculation.

Aluminum Price	1550
Premium Rate	0.03
BPA Rate	23
BPA Allocation	100

Mwh/Tonne	13.199
	Plant A (modern prebake)
Potential Demand	457
Cost Components	
Alumina	403
Carbon	90
Labor/Other	400
Sustaining Capital	80
Electricity Cost Max	623.5
Electricity Price Max	47.24
Electricity Price	$30
Demand @ Price	457

Figure L-50: Cost structure of Aluminum Smelter

Given the cost structure of the smelter, including the smelter's requirement for electricity, alumina, carbon, labor, and other fixed costs, and with the knowledge of aluminum price and the allocation and the price for any BPA power, a breakeven price for electricity can be determined. For each price of electricity, we can restate the total demand for all seven smelters as a function of aluminum prices. Figure L-51 illustrates supply curves for regional smelter load, given assumptions about the price of power available to the smelters.

In the portfolio model, we capture this response of smelter load to electricity price and aluminum price with a single UDF. This function tracks the response of each of the seven smelters separately, based on its unique cost structure. There are initial conditions provided for each smelter, representing the number of months that the smelter has been shutdown. If any smelter is shutdown for more than five years, it will be permanently retired. More details about these operations appear below.

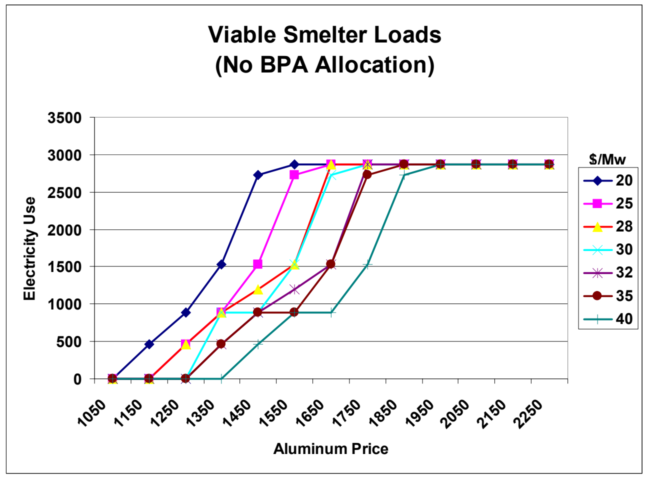


Figure L-51: Supply Curves for Regional Smelters

The model needs a criterion for determining whether a given plant should shutdown or restart. Figure L-52 illustrates a typical decision criterion for a smelter. Along the horizontal axis is time; along the vertical axis, the value of the decision criterion, denominated in arbitrary units. There is a horizontal line that determines whether the outlook for the smelter is favorable. We may think of the criterion as roughly the spread between aluminum electricity prices, although the reader will see shortly that the smelter-specific criterion is more detailed than this. The criterion starts out above zero, in positive territory, but soon becomes negative. The smelter enters an evaluation phase. During the evaluation phase, a decision maker would consider whether to shutdown the plant. If the decision criterion remains negative throughout the evaluation phase, the plant will be shutdown and remain down for a minimum amount of time. Later, when the criterion turns positives, the smelter enters

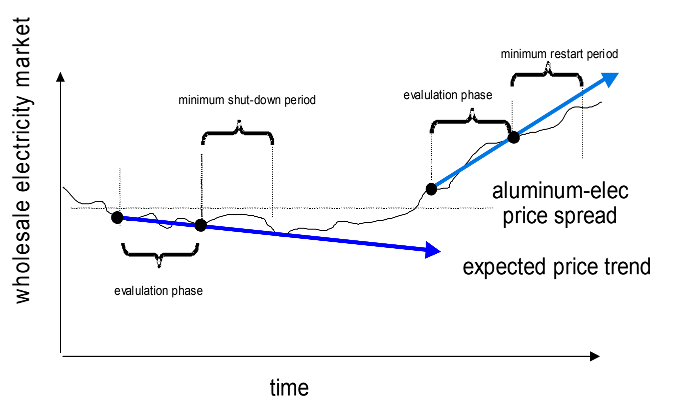


Figure L-52: Decision Criterion for Smelter

another evaluation phase. If the outlook for the smelter remains favorable throughout the evaluation phase, the smelter restarts. Once restarted, however, it must remain in service for a minimum amount of time. These minimum startup and shutdown times represent the time to adjust work schedules and contracts and to prepare equipment. Evaluation is ongoing during the minimum times.

The smelter-specific decision criterion *d* follows the profitability calculation in Figure L-50:

$$d = r - c \quad (\$/\text{mT}),\ \text{where}$$
$$r = p_A(1+\rho) \quad (\text{revenue in } \$/\text{mT})$$
$$c = 0.26 p_A + c_f + p_e \alpha \quad (\text{cost in } \$/\text{mT})$$

and

p_A is price of aluminum ($/mT)

ρ is premium rate

c_f is fixed cost of carbon, labor, capital ($/mT)

p_e is price of electricity ($/MWh)

α is electricity intensity (MWh/mT)

The cost of alumina is $0.26p_A$. The decision criterion reflects any evaluation, so the plant operation will respond immediately to its value. Rearranging these terms, we have

$$d = p_A(1+\rho-0.26) - c_f - p_e\alpha$$

Whenever the criterion *d* turns from negative to positive, smelter operation continues or, if the smelter has been shutdown, restarts if minimum shutdown time is satisfied. When the criterion *d* turns from positive to negative, the smelter remains off-line or, if the smelter has been operating, shuts down if minimum in-service time is satisfied.

Turning to the workbook, we point out that, as opposed to all of the other UDF functions, some data hides in the UDF that calculates smelter capacity[22]. The portfolio model adopts this alternative to initializing the UDF from the worksheet because Council staff believes smelter parameters will not change significantly. If users wished to change some of these values, however, they are available in the VBA module containing the UDF code. Parameters that the user may specify are the following:

```
Const lNumberOfDSIPlants As Long = 7
Const dSmelterPricePremium As Double = 0.03
Const dAluminaCostFraction As Double = 0.26
Cosnt lNumPeriods as Long = 80

lDmd(0 To lNumberOfDSIPlants - 1)
```

[22] In range {F326:O327}, the reader will find values that appear to be parameters for the smelter UDF. This is a vestige of an older UDF. They should have been cleaned out. The model does not use these values.

dMWhPerTonne(0 To lNumberOfDSIPlants - 1)
dNonPowerCostPerTonne(0 To lNumberOfDSIPlants - 1)
dDiscountPowerPrice(0 To lNumberOfDSIPlants - 1)
dDiscountPowerAmt(0 To lNumberOfDSIPlants - 1)
lNumPersDown(0 To lNumberOfDSIPlants - 1)
lNumPersUp(0 To lNumberOfDSIPlants - 1)
lMinNumUpTimePers(0 To lNumberOfDSIPlants - 1)
lMinNumDownTimePers(0 To lNumberOfDSIPlants - 1)
dUpThreshold(0 To lNumberOfDSIPlants - 1)
dDownThreshold(0 To lNumberOfDSIPlants - 1)
lInitialPeriodsDown(0 To lNumberOfDSIPlants - 1)
lPeriodsDownBeforeShutdown(0 To lNumberOfDSIPlants - 1)

Because of the proprietary nature of some of this information, we do not provide smelter-specific values in this documentation. Most of the parameters in the list above should be self-explanatory. The parameters dUpThreshold and dDownThreshold permit users to specify thresholds above or below zero for the decision criteria on a plant specific basis. The parameter lPeriodsDownBeforeShutdown specifies how many periods of negative decision criteria values to permit before permanently shutting down the smelter.

The electricity price that the decision criterion uses may be a melded price, reflecting not only market price but also some subsidized power. The Wenachee smelter, for example, gets 40% of its power from Chelan PUD at a discount from market, and the portfolio model reflects that fact. The UDF that computes smelter load assumes that the smelter either operates at full capacity or does not operate at all. For this reason, decisions are made based on the melded price of electricity, not on the prices of each source of electricity. With this assumption, the user stipulates any discounts through the values of dDiscountPowerAmt and dDiscountPowerPrice. The definition of dDiscountPowerPrice, however, is idiosyncratic. We can express electricity price generally as:

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n} + p_m \times MWh_m}{MWh_{s_1} + \cdots + MWh_{s_n} + MWh_m}$$

where

p_{s_i} is the price of discounted power from source $i, i = 1...n$

MWh_{s_1} is the amount of discounted power from source $i, i = 1...n$

p_m is the market price

MWh_m is the market amount

Let S denote the total amount of discounted power and D denote the total demand.

$$S = MWh_{s_1} + \cdots + MWh_{s_n}$$
$$D = S + MWh_m$$

Because the denominator is just the total amount of demand D for the smelter, we have

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n}}{D} \; + \; p_m \times \frac{(D-S)}{D}$$

Now, the first term is entirely fixed. One can think of it as the weighted price of power,

if the price of market power were zero. This is the definition of dDiscountPowerPrice. The convenience of this definition is that if dDiscountPowerPrice and dDiscountPowerAmt (S) are zero, then $p_e = p_m$. Moreover, if discounted power comes in various amounts from various sources, these two variables alone still capture the total effect.

In the workbook, we find in cell AQ 327 the following formula

=lfDSICol(AP$227, AP$270, AP$46,2, AP327)

The UDF lfDSICol returns the value for the total smelter load in the region. The definition of this function is as follows

```
Function lfDSICol(ByVal sPowerPrice As Single, ByVal sAluminumPrice As Single, _
   ByVal lPeriod As Long, ByVal lSide As Long, ByVal dummy As Long) As Long

Takes:
sPowerPrice        - Electricity Price ($/MWh)
sAlumPrice         - Aluminum Price ($/metric tonne)
lPeriod  - period for which the calculation applies.  Note that to stabilize calculation, we are
           pointing to the period _preceding_ the period in which the function is called, consistent
           with the principle of causality
lSide      = 0 for east, 1 for west, 2 for both

Returns:
           Total smelter load (MW) as Long
```

The first two parameters point to the 18-month averages for electricity aluminum price in rows 227 and 270, respectively. Taking the average over an extended period in the recent past provides both inertia to the decision and a reasonable evaluation period. As discussed later in the section "Decision Criteria," these prices are proxies for forward prices. The UDF uses the flat price for electricity, the average of on and off peak electricity.

The third parameter merely tells the UDF for which period it is computing a value. The fourth parameter, which has the fixed value 2, specifies that the UDF return the sum of the loads for Eastern and Western smelters. If the user chose to employ this UDF in a different application, he or she could select loads for just those smelters in one subregion. The final parameter is merely a dummy that forces calculation of the previous period's UDF before execution of this period's UDF.

The formula in cell AQ328 computes the energy requirement in megawatt hours.

=1152*$AQ$327

This is merely the energy in average megawatts times the number of hours on peak. The cost in millions of dollars is computed in AQ329.

=AQ328*$AQ$204/1000000

Because we assume no correlation between energy prices and this load, the cost of this load is merely the product of the load and the price divided by one million. The off-peak calculation is identical.

One option that a user should consider if he or she wants to implement this UDF in their own application is that this is a specific application with potential generalization to other industries. That is, the modeling of any other industry that relies heavily on electricity, such as petrochemicals or paper refining, can make use of this UDF. Instead of the spread between aluminum prices and electricity prices, one would consider the spread between paper prices and electricity prices, for example. Indeed, the spread between the costs of any two commodities or any predictor of loads could provide a general decision criterion, although the user would obviously have to modify the UDF somewhat.

Finally, there is a utility available that permits users to view the status of each smelter for a particular future. This utility, a separate UDF, is not available in the portfolio model but is upon request.

In summary, the DSI UDF permits the portfolio model to quickly calculate total smelter load in the region based on each smelter's profitability, as determined by the prices for aluminum and electricity. It provides an idea of the long-term load response of these industries, as opposed to the short-term response captured through, for example, demand response. The UDF accommodates user-specified assumptions through VBA constants in the code, including those regarding discounted power. Although tailored to the aluminum production industry, the concepts and much of the code in this UDF are applicable to other industries as well.

New Resources, Capital Costs, and Planning Flexibility

Certain aspects of resources permit a decision maker to respond to changing circumstances quickly or inexpensively. Collectively, we refer to this as planning flexibility. Sources of planning flexibility include:

- Modularity (small size) permits a more exact match to requirements and reduces fixed-cost risk.
- Short lead-time facilitates rapid response to opportunities or unexpected requirements.
- Cost-effective deferral or cancellation is usually available only for a limited time during the construction cycle. The decision maker values the ability to change his or her mind without incurring excessive cost.

The value of flexibility played a key role in the 2000-2001 energy crisis. The region saw load management and conservation respond to changing circumstances much faster and more effectively than conventional thermal supply-side resources.

Valuing this source of flexibility is nothing new to the Council. Planning flexibility was explicitly valued in 1991 plan with the ISAAC model. However, ISAAC used load projections to decide when to add resources, instead of using market value like the portfolio model.

The discussion in this section focuses on the third source of planning flexibility listed above, cost-effective deferral or cancellation. The portfolio model captures the value of the other sources of planning flexibility, but valuing cost-effective deferral or cancellation requires special spreadsheet logic. This section describes how the portfolio model achieves this objective with a special UDF.

Although capturing planning flexibility has been a primary objective in the design of this special UDF, the UDF also performs the important function of computing capital and fixed costs for new resources. The discussion of valuation costing that begins on page L-13 addresses variable costs. The fixed costs of existing resources do not bear on any decisions in the regional model, but total system costs still require computing fixed and capital costs for additions. That latter task belongs to this special UDF.

Cost-effective deferral or cancellation of power plants depends on the construction cycle. Cash flow, in turn, provides an important perspective on the construction cycle. A typical cash flow pattern appears in Figure L-53. Cash flow determines natural decision points. For the first 18 months in the example illustrated in Figure L-53, only siting and permitting take place. Siting and permitting are inexpensive activities. The decision maker incurs relatively little expense if he or she interrupts or cancels the power plant during this phase. After completion of siting and permitting, however, construction begins, which typically requires a substantial initial investment. The project breaks ground on administrative buildings and substations. The owner may need to make deposits on some of the most expensive equipment, such as turbines or boilers. After some period of construction, nine months in our example, the project reaches a final decision point. If the project is to proceed, the owner must take delivery of and pay for the most expensive pieces of equipment. Beyond this point, the owner will complete construction, because most of the costs are effectively sunk. The owner presumably completes the plant and brings it online.

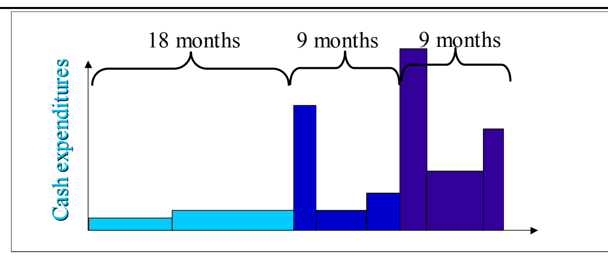


Figure L-53: Partitioning the Construction Cycle

As in the case of aluminum smelters, the portfolio model uses a decision criterion to determine whether to proceed through each phase of construction. The regional portfolio model assumes, however, that the first phase of siting and licensing is completed.[23] The details of the decision criterion are below, but it functions in a manner identical to that for DSIs. Given that siting and permitting is complete for a specific resource in a given plant, the decision criteria will immediately determine whether to proceed with the optional phase of construction. At any point during the optional phase of construction, the model may defer or cancel construction if the criterion turns negative. If the model defers construction ("mothballs" the plant) and construction does not resume within a number of periods specified by the user, construction terminates and the project incurs cancellation costs. During deferral, the plant accrues mothball costs instead of construction costs. Once the requisite time and cost for optional construction finishes, committed construction begins and continues until the plant goes online. Figure L-54 illustrates the decision criterion in a manner similar to Figure L-52, and Figure L-55 illustrates the effect that an adverse decision criterion value in periods five through nine would have on three plants started on a staggered schedule. The negative criterion value affects only the last plant, initiating the third period, because the criterion acquires a negative value after the planning period and before the committed construction period.

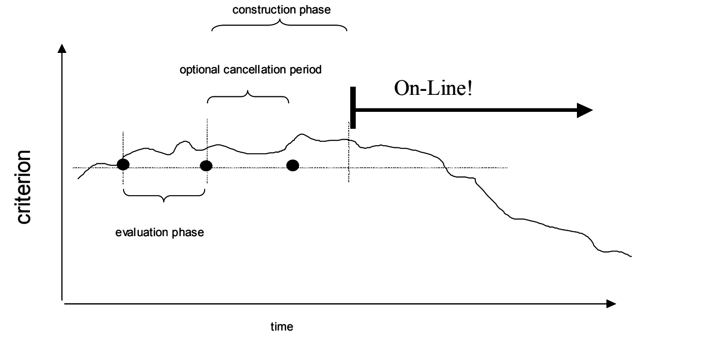


Figure L-54: Decision Criterion and Phases

As Figure L-55 implies, there are cohorts of plants available for planning or construction commencement in each period of the study. Each cohort has identical cost and operational characteristics. The UDF returns the cumulative capacity and total cost across all cohorts. Although the UDF makes cohorts available in each period, the user controls their size and availability by specifying a particular plan, so size and availability typically vary from period to period. The description of how to control the size and

[23] Here the fiction of a 20-year resource plan asserts itself. Although required by statute, the Council understands that a fixed blueprint for resource additions 15 years in the future, even the inexpensive siting and licensing process, is unrealistic. The purpose of the 20-year plan instead is to assure that the necessary commitments made in the Action plan do not preclude future opportunities or burden future generations in the region with imprudent, long-term obligations. Without specific future commitments, however, how does the region obtain a clear idea of the relationship of current decisions, made in the Action Plan, and future actions that might be precluded or required? For example, if the Action Plan tacitly relies on wind in the next decade, although it may not call for it in the next five years, how would the region know when to build long-lead time transmission now? Clearly, this requires a specific long-term resource plan. A fixed plan of construction, however, does not permit valuation of flexibility. The approach of the regional portfolio model is to commit to specific construction preliminaries, to the siting and licensing for specific amounts of specific technologies at specific points in the future. The Council believes this approach balances the need for specificity with the valuation of flexibility.

presence of each cohort through "decision cells" appears in the section "Parameters Describing the Plan" on page L-72.

If the user stipulates, the UDF that performs the function of tracking construction for cohorts of power plants is capable of adding plants *whenever* the decision criterion is positive. The intended application for this feature is modeling the market-driven addition of power plants. Using this feature, the user can specify that construction costs are different depending on whether power plants are planned for or are added when market conditions are favorable. Recent history shows that when market conditions are attractive, the demand for power plants and their components increases, as does the associated cost. The regional portfolio model, however, does not implement this feature. Instead, the optimizer controls all additions. The optimizer selects the timing, sizing, and choice of technology to find an optimal plan given risk constraints.

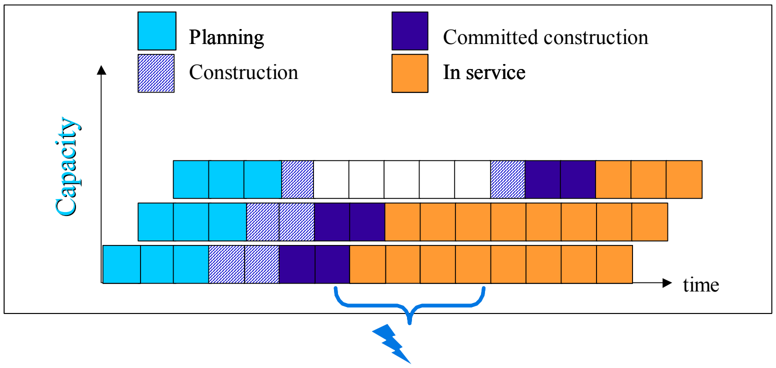


Figure L-55: Effect of Decision Criterion on Cohorts

The UDF can also provide for special cash flow features that the regional model *does* incorporate. First, it can capture sunk costs associated with a plan, specifically the sunk costs for planning, siting, and licensing. This takes place despite there being no planning periods per se with which to associate those sunk costs. Instead, the sunk costs merely add to subsequent levelized costs. Second, the UDF can represent the situation where the first period of optional construction incurs the total cash flow associated with that phase of construction. This type of cash flow pattern is a "pulse." Ordinarily, levelized cash flow rates increase in steps of constant size over periods when there is construction activity. The regional model uses pulse cash flow instead to better reflect the jump in cash flow at the beginning of the optional phase of construction, as illustrated in Figure L-53. Council staff felt the difference in cash flow patterns might affect valuation decisions.

The UDF also easily accommodates capacity expansion *without* planning flexibility, if the user wishes to either "hard-wire" new capacity or have an optimizer do so. The user assigns the cells containing the decision criterion a constant positive value. The Crystal Ball "decision" cells, described below, then control all additions directly.[24]

The scenarios in Chapter 7 of the plan illustrate the response of a plan to changing circumstances. These scenarios demonstrate, among other things, how this UDF controls

[24] There must be at least one planning or construction period, however.

the construction and completion of power plants. To the extent these changes are responsive and inexpensive, they add to the value of a plan.

In the workbook, three worksheet ranges control the performance of capacity additions and costing. The first are the parameters describing each technology. These values represent such things as capital cost, and they do not change unless the user changes the description of a plant. The second are the Crystal Ball decision cells, which the optimizer controls. These specify the timing, size, and type of technology, and their values specify the plan. The third are the period calculations, the values of which typically change under each future. This section will discuss each of these in turn.

Parameters Describing Each Technology

The worksheet cells that control the characteristics of any new capacity appear in the range {B454: P519}. The cells that control the characteristics for the generic combined-cycle combustion turbine (CCCT) units appear in Figure L-56. Identical sets of parameters, obviously with different values, exist for single cycle combustion turbines (SCCT), coal plants, wind plants, and optionally demand response and coal tar processing CCCTs in Alberta.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
453																
454		Criterion_S	Planning_P	Optional_C	Committed	Planning_C	Mothball_C	Cancellatio	Constructic	CancelThre	Const Cost	ResourceLi	OptionLife (	PermitMark	PlannedPla	Index
455		CCCT Crite	0	4	4	0	0.000292	0.0116796	0.0029199	-99999	-0.086%	80	20	FALSE	0.001491	0
456																

Figure L-56: New Capacity Parameters

Before we proceed with the description of each of the parameters appearing in this range, it may be useful to explain several conventions. First, the units of time are periods, as defined for the portfolio model. The regional model uses the hydro-year quarter. The escalation rates for capital costs are also expressed in rate of change per period. Second, all cost rates are denominated in real levelized millions of dollars per megawatt per period squared. The determination of this value is according to the following equation:

$$\frac{\text{RL \$M}}{MW \bullet per^2} = \frac{RL\$}{kWyr} \bullet \frac{yr}{per} \bullet \frac{1}{\# \, per} \bullet \frac{kW}{MW} \bullet \frac{\$\text{M}}{\$} \qquad (5)$$

This appendix has already discussed the reasons for using real levelized dollars. The reason for expressing cost rates in terms of dollars per period per period (or equivalently, dollars per period squared) is that construction can halt during the earlier construction phase. It is therefore necessary to stipulate the *rate* at which period construction costs accumulate. Another subtlety here is that this model uses standard months and standard years for variable cost calculations. (See discussion on page L-11.) To make sure that variable and fixed costs are consistent, the model uses fixed costs in dollars per kilowatt-***standard*** year, rather than the more conventional dollars per kilowatt-year. Thus, the second term on the right-hand side of equation (5) has a value of about 0.23, which derives from the following equation:

yr/per = (std mo per std qtr)(wks per std mo)(days per wk)(hours per day)/(hours per year)
= (3)(4)(7)(24)/(8760)

The third term on the right-hand side of equation (5) is simply the reciprocal of the number of periods in the phase of construction. In the example that appears in Figure L-56, this term would have a value 1/4 for the phase associated with committed construction.

So, for example, assume a CCCT with total fixed cost, including fixed fuel and transportation but excluding planning costs, of $101.50/kWyr. This real levelized cost is in 2004 dollars, ignoring escalation. If construction requires eight hydro quarters (two years), the equivalent cost rate from equation (5) would be

$$0.0029181 = (101.50)(0.23)(1/8)(1000)(1/1000000)$$

which corresponds to the construction cost rate in column I of Figure L-56.

The only exception to this characterization of costs is for the treatment of sunk costs, described above. If the numbers of periods for the planning phase in column C is zero, and non-zero "planned planning" costs appear in column O, the UDF assumes sunk costs. In this special case, the cost rate in column O applies.

With this background, consider the entries in the columns of Figure L-56:

- Column B has a name that specifies which planning flexibility record Olivia used to create this description. (The description of Olivia appears in the section "Olivia" starting on page L-136.) The value in this column has no meaning otherwise in the portfolio model.

- Columns C through E indicate the number of periods in the planning, optional construction, and committed construction periods, respectively. For example, optional construction lasts four periods, which correspond to one year because the periods in the regional model consists of hydro quarters. The number of planning periods in all of these capacity expansion options are zero, because the model assumes planning is complete and planning costs are sunk, as described above.

- Columns F through I contain the cost rates associated with the various phases of planning and construction. During each period of these phases, the plant cost accumulates R x C x $(1+E)^P$ millions of dollars, where R is the relevant cost rate, C is the plant capacity in megawatts, E is the escalation factor in column K, and P is the number of periods since the beginning of the study. Cancellation, if it occurs, happens in one period. Like all other costs, however, cancellation costs contribute to subsequent periods for the duration of the life of the plant, stipulated in column L.

The cost rate in column F is always the cost associated with unplanned construction, driven by market conditions. The model implements the use of unplanned construction in response to market conditions only when the user sets the value in column N is TRUE *and* there is no cohort planned for the period. Otherwise, the model uses the planning cost rate in column O. (See the discussion of choices for columns N and O, below.) The regional model does not use unplanned construction in response to market conditions, and the value in this column is zero for all new capacity candidates.

- Column J has the value of the cancellation threshold. If the decision criterion falls below this value, the plant cohort will cancel immediately and will incur the cancellation penalty. None of the plants in the regional model use this option; the value of the cancellation threshold is instead set arbitrarily low.

- Column K identifies the escalation rate for capital costs, including the capitalized planning and construction costs. The rate is per portfolio model period. For example, if the annual rate of increase is negative 0.3423 percent per year and the period is a hydro quarter, as in the case of the regional portfolio model, then the period escalation rate is $-0.00085682 = (1- 0.003423)^{1/4}-1.0$. Note that conversion from conventional years to standard years is neither necessary nor appropriate. Although the numbers of hours in each are different, standard years represent conventional years. That is, costs four standard quarters later will be five percent higher, too.

- Column L specifies the resource life in periods. In the regional model, 80 periods is 20 years. The model distributes all real levelized costs according to the resource life. The associated real levelized cost contributes to the total real levelized cost when the event (planning, construction, cancellation) occurs, disappears from the total after the resource life's number of periods, and applies to all intervening periods. Note that this implies the cost contribution typically begins and ends in periods other than the on-line date or retirement period of the plant.

- Column M has the maximum number of periods that the model will hold the plant in its mothballed state before canceling the plant. Its value is arbitrary, and setting the value higher than the number of study periods effectively turns off this option.

- If the user wishes the model to start a plant cohort in any period where the decision criterion is positive, they indicate so by setting to TRUE the value in column N. In this case, the model would interpret values that otherwise would determine the plan as capacity ramp rates. Each cohort, if completed, would contribute the capacity specified by the ramp rate. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") The calculation of planning costs also depends on the value in this column, as explained in the next bullet.

- How the model interprets the value in column O depends on the value of column C, the number of planning periods. If the number of planning periods is zero, the cost rate in column O is that for the sunk cost associated with planning incurred before construction begins. As for all cost rates, these are denominated in real levelized millions of dollars per megawatt per period squared, although the UDF assumes only one period for sunk costs. In the example appearing in Figure L-56, the value is .001491. The costs incurred quarterly due to sunk planning and siting is the product of the unit capacity, 610 MW, times this value, times the escalation factor, or about $910,000 per quarter. All new plants in the regional model use the convention of sunk planning and siting cost.

  If on the other hand the value in column C, the number of planning periods, is greater than zero, then the determination of the planning cost rate hangs on the value of the market addition flag in column N. If the market addition flag is FALSE, the cost rate in column O applies to each planning period, as in the description of costs in columns F through I, above. If the market addition flag is TRUE, then the cost rate in column O applies to each planning period only if there is a non-zero entry in the decision cell for the cohort. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") Otherwise, the cost rate in column F applies to each planning period. Presumably, the cost rate in column F would be higher than that in column O, reflecting higher costs of not planning for capacity additions. Although the higher costs are associated with planning in the portfolio model, they certainly may represent the total of higher costs due to both planning and construction.

One additional controlling parameter unfortunately does not appear here. The switch that determines whether costs in the optional phase of construction are "pulsed," as in the regional model, or applied as construction proceeds is at the top of the VBA code module "mod_PlanningFlex"

```
Private Const bTrigger As Boolean = True 'determines whether all construction costs _
    for optional construction are incurred at the beginning of construction
```

Council staff added this parameter and capability late in the modeling process, and they never completed the proper establishment in the worksheet interface.

These parameters and values may be initially confusing. Once set, however, the user typically would have little need to modify them, except perhaps to update construction costs. A numerical example of how the model interprets these parameters to arrive at final costs appears below in the section "Period Calculations" beginning on page L-74.

Parameters Describing the Plan

A plan is defined by the timing, size, and choice of technology for new resources. As explained in the previous section, the timing of new resources in the regional model is, more precisely, the earliest date of new construction. The resource's production of electricity may occur as early as the planners' scheduled completion of construction or much later or not at all, depending on circumstances.

In the worksheet, the range {R3:CS9} determines the plan. A simplified view of this range appears in Figure L-57. This range of cells contains special cells that are under the direct control of Decisioneering's Crystal Ball and OptQuest. Decisioneering Inc. refers to these as "decision cells." OptQuest is the Excel add-in performs stochastic, nonlinear optimization. During the process of seeking a Least-Cost, Risk-Constrained plan, OptQuest modifies the values of these decision cells. The decision cells in Figure L-57 are yellow, the default color for decision cells under Crystal Ball.

In the regional model, potential capacity additions occur according to an irregular schedule. The first opportunity for construction is in September 2003 (column R).[25] The next opportunity is December of calendar year 2007. After this, opportunities fall every two years through December of calendar year 2019.

PlnCap_0 = 0

	N	R	S	AH	AI	AJ	AP	AQ	AR	AX	AY	AZ	BF	BG	BH
1		Sep-04	Dec-0	Sep-08	Dec-08	Mar-0	Sep-10	Dec-10	Mar-10	Sep-12	Dec-12	Mar-1	Sep-14	Dec-14	Mar-
2	Capacity Data ID														
4	CCCT Capacity	0.00			0.00			610.00			610.00			610.00	
5	SCCT Capacity	0.00			0.00			0.00			0.00			0.00	
6	Coal Capacity	0.00			0.00			400.00			400.00			400.00	
7	PRD	0.00			500.00			750.00			1,000.00			1,250.00	
8	Wind 1	0.00			0.00			1,200.00			1,200.00			1,200.00	
9	Wind 2	0.00			0.00			0.00			0.00			0.00	
10															

Figure L-57: New Capacity Decision Cells

These dates are a bit arbitrary. Construction typically begins in December, because December is the closest to the beginning of a calendar year, a convenient milestone for describing a plan. Occasionally, utilities will attempt to complete construction before the end of a year for tax purposes, as well. It is crucial that the portfolio model use as few construction dates as possible. Increasing the number of choices for start dates and for increments of capacity additions can dramatically increase the number of possible plans. Indeed, with the rather conservative choice present in the regional model, the number of possible plans still exceeds 10^{24}. This is the key reason optimization is useful in identifying least-cost plans. Early in the study process, it became apparent that the model constructs few resources in the first 10 years, largely due to a surplus of existing resources in that period. It made sense therefore to sample the second decade of the study period more carefully than the first decade. These considerations led to the pattern of earliest construction dates that appear in the final regional model.

The previous section described how there are cohorts of a given plant technology available in each period of the study. The user, however, must make a given cohort available by assigning a nonzero capacity to the period in which the cohort originates.

[25]The header label in Figure L-57 and in the model says "September 04" because the regional model uses hydro years. The regional model deems September through August of the following year a hydro year or streamflow year. The calendar year in which it ends, in this case 2004, designates the hydro year.

There is an Excel range name in column R of each row corresponding to a new resource. (See for example the range name **PlnCap_0** in cell {R 4} of Figure L-57.) At the beginning of a Monte Carlo run for a given plan, the workbook finds this range and reads the associated row of values to determine which cells are blank and to obtain the values from nonblank cells.

How the model interprets the values in each row depends on whether the user has specified that additions are market-driven. (See discussion of columns N and O in the previous section.) In the regional model, additions are *not* market driven. If additions are not market driven, nonblank entries represent cumulative megawatts of the resource from that period forward until the next nonblank entry. The model permits only cohorts that start in the nonblank period *and* only if the value in the period increases from the previous nonblank value. This means that if the decision criterion is negative in that period, then cohort never begins construction.[26] Consider the situation for CCCT in Figure L-57. The cumulative capacity in December hydro year 2010 and December of hydro year 2012 are both 610 MW. This means that the model can add 610 MW in hydro year 2010, but it cannot add more capacity in hydro year 2012. It is the change in cumulative capacity that enables potential new construction.

If, instead, the user specifies that additions *are* market-driven, nonblank entries represent incremental megawatts possible in that period. The same ramp rate applies to all futures periods, unless there is a nonblank entry that changes this ramp rate. When additions are market driven, the cohort of the given technology will become active in any period where there is a positive value for the decision criterion. The prevailing ramp rate in a given period determines the amount of capacity that the model will add. Whether a non-blank entry specifies the ramp rate or the ramp rate is inherited from an earlier period *does* affect planning costs. If there is a nonblank incremental capacity entry, lower planning costs are available in the portfolio model, as described in the previous section. Otherwise, the model will use higher cost for planning.

Period Calculations

The third and final area of the worksheet that controls the capacity addition and costing are the period's cells. These cells contain the functions that return the capacity and cost. Cell {AQ455} contains the following formula, which returns the total capacity across all cohorts for the generic CCCT unit:

```
=lfPFCap(AQ$302,AQ$46,$P455)
```

The definition for this UDF is as follows

[26] Of course if they were nonblank entries in the subsequent period, the technology would "get another chance." This is not the case in the regional model, however, where options for the beginning of construction occur only once every two years.

Function: lfPFCap(ByVal dCriterion As Double, ByVal lPeriod As Long, _
ByVal lPlant As Long) As Long

Takes:

dCriterion - Prices or criteria values that would indicate success moving forward
lPeriod - 0-based index to period for which the calculation pertains
lPlant - 0-based index to plant for which computation pertains

Returns: A long with the number of MW

All of the necessary information regarding the technology and the plan are available in memory arrays to the special UDF lfPFCap. Based on this information and the value of the decision criterion, the UDF determines the appropriate amount of capacity to add, according to the rules described earlier. The UDF updates the real levelized costs at the same time. There are identical formulas for generic coal plants, wind plants, and the other new resources in other periods. Each generic technology, of course, points to its own decision criterion and plant index.

The second special UDF, sfPFCost, then retrieves the period real levelized costs totaled across all cohorts for this technology.

=sfPFCost(AQ455,AQ$46,$P455)

The definition of the special UDF is as follows

Function sfPFCost(ByVal lDummy As Long, ByVal lPeriod As Long,
ByVal lPlant As Long) As Single

Purpose:

This function is a companion to lfPFCap. It reads the cost matrices and returns the appropriate period's information

Takes:

lDummy - Forces calculation of lPFCap
lPeriod - 0-based index to period for which the calculation pertains
lPlant - 0-based index to plant to which computation pertains

Returns:

The real dollar amount ($M) for the period, after escalation, but before discounting

Up to this point, this section has discussed the use of the capacity expansion and planning flexibility logic in detail but has not provided an example of how all these pieces fit together. To see how the model interprets the parameters and values presented above, consider Figure L-58. This illustration features two special UDFs that facilitate viewing the model's internal workings. The UDF "lfPFCohortStatus" returns the status of a given cohort for each period in the study; the UDF "sfPFCohortCost" returns the period cost for that cohort. Because the results returned by the "lfPFCap" and "sfPFCost" are aggregate capacity and period cost across all cohorts of a given technology, it is useful for diagnostic and training purposes to have UDFs that permit an analyst to study the workings of one cohort in isolation.

These UDFs are available in the portfolio model, but the only range in the regional model that refers to them is {R463:CS464}. In the model, placing an "m" before the equal sign in their formulas has deactivated them. The “m” forces Excel to interpret the formulas as strings. In Figure L-58, removing the “m” reactivated them, and pointing the parameters to updated cells eliminated some bad initial references. The VBA code module “mod_PlanningFlex” defines and recommends how to use the status UDFs, so this appendix will provide no further explanation.

The cursor in Figure L-58 is on cell {AQ464}, and the formula in that cell appears in the equation window at the top of the figure. Formula auditing is on, revealing that the parameters of the UDF point to the cohort index, to the period, to the plant index, and to the previous cell. The reference to the previous cell, as elsewhere, forces the calculation order by guaranteeing the worksheet updates the previous formula before the subject cell. Other instances of this formula in row {464} have identical parameter formulas but of course point to different period columns and different previous cells.

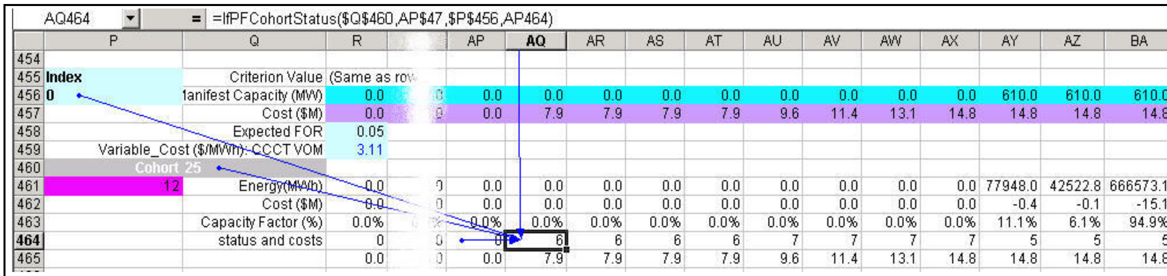


Figure L-58: Status Functions

In Figure L-58, the UDF lfPFCohortStatus returns the value 0 in row {464} up to column {AQ}. In columns {AQ:AT}, the value is 6; in columns {AU:AX}, the value is 7; and in columns to the right of {AX}, the value is 5. These values represent the status of cohort 25, plant 0 (the CCCT) in each period. Cohort 25 is the cohort that begins in period 25, the period in column {AQ}. The following table defines the meaning of the status codes:

lUnderConsideration As Long = 0
lNeverStarted As Long = 1
lPlanned As Long = 2
lMothballed As Long = 3
lCancelled As Long = 4
lCompleted As Long = 5
lOptionProceed As Long = 6
lConstrProceed As Long = 7
lRetired As Long = 8

The next row contains instances of the UDF sfPFCohortCost, which return costs for cohort 25 only. *With this information and the value of the decision criterion in each period, the user has the means to verify the calculations determining capacity addition and costs in each period.*

Start with the description of the construction cycle of the CCCT, including the percentage of costs and amount of time spent in each of the construction phases:

name		Siting and Permitting	Optional Construction	Commited Construction	Totals
CCCT	Periods to complete phase (quarters)	8	4	4	16
CCCT	Periods to complete phase (months)	24	12	12	48
CCCT	Cost to complete phase (Overnight, MM 2000$)	20	66	234	320
CCCT	Cost to complete phase (Overnight, 2000$/kW)	33	108	384	525
CCCT	Cost to complete phase (% Overnight)	6%	21%	73%	100%

Figure L-59: CCCT Construction Cycle

In Figure L-56, the specification of periods for optional and committed construction is evidently consistent with Figure L-59. The next step is to determine the cost and cost escalation rates for planning and construction. Figure L-60 identifies the real levelized costs for generic CCCT plant started in each year listed in column A. The capital cost in column T includes planning costs. The calculation adds fixed O&M and fixed fuel costs to arrive at a total fixed real levelized cost for each generation of generic CCCTs. From this calculation, we take away two numbers, the 2004 levelized cost in cell Z38 and the quarterly cost escalation rate in cell Z62. This quarterly escalation rate calculation is on page L-71; it matches the escalation rate in Figure L-56.

Z40 = =W40+U40+T40

	A	T	U	V	W	X	Y	Z
32	Levelized costs by service year (2004$):							
33								
34		Capital (2004$)	Operation (2004$)					
35								
36								
37	Service Year	($/kW/yr)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Fixed Fuel ($/kW/yr)	Variable Fuel ($/MWh)		Total fixed for portfolio
38	2004	$53.77	$29	$3.11	$25	$25		$108
39	2005	$53.56	$29	$3.11	$26	$24		$108
40	2006	$53.34	$29	$3.11	$26	$24		$108
41	2007	$53.13	$29	$3.11	$26	$24		$107
42	2008	$52.92	$28	$3.11	$26	$24		$107
43	2009	$52.71	$28	$3.11	$26	$24		$107
44	2010	$52.50	$28	$3.11	$25	$24		$106
45	2011	$52.29	$28	$3.11	$25	$24		$106
46	2012	$52.08	$28	$3.11	$25	$24		$106
47	2013	$51.87	$28	$3.11	$25	$24		$105
48	2014	$51.67	$28	$3.11	$25	$24		$105
49	2015	$51.46	$28	$3.11	$25	$24		$104
50	2016	$51.25	$28	$3.11	$25	$24		$104
51	2017	$51.05	$28	$3.11	$25	$24		$104
52	2018	$50.85	$28	$3.11	$25	$24		$103
53	2019	$50.64	$28	$3.11	$24	$24		$103
54	2020	$50.44	$28	$3.11	$24	$23		$102
55	2021	$50.24	$28	$3.11	$24	$23		$102
56	2022	$50.04	$28	$3.11	$24	$23		$102
57	2023	$49.84	$27	$3.11	$24	$23		$101
58	2024	$49.64	$27	$3.11	$24	$23		$101
59	2025	$49.44	$27	$3.11	$24	$23		$100
60	Escalation, 2004-25	-0.399%	-0.23%	0.00%	-0.32%	-0.34%		-0.342%
61								
62							Quarterly	-0.00085682

Figure L-60: Year-by-Year Real Levelized Costs

Not all of the $108/kWyr is construction cost. Figure L-59 specifies the portion of this that is planning cost, and the difference is the basis from the construction cost rate estimate illustrated in Figure L-61. The detailed construction cost rate calculation for this CCCT already appears as the example on page L-70. Applying the planning fraction of construction costs to the total construction cost in $M/MW gives the planning cost rate in Figure L-62. Recall that, despite the number of periods for planning that appears in Figure L-59, the number of periods is taken as one (1) when the user models planning costs as sunk, as does the regional model. This planning cost rate matches that in Figure L-56.

CCCT		
	RL$/kWyr	$101.50
	1/#per	0.125
	RL $M/MW/per/per	0.0029199

Figure L-61: Construction Cost Rate

D72 = =D9/(1-D9)*(E5+F5)*D40

	A	B	C	D
69				
70		**Planning Costs**		
71				
72		CCCT		0.001491007
73				

Figure L-62: Planning Cost Calculation

Having reproduced the values in Figure L-56, the final step is to verify the costs in Figure L-58. From the status codes, it is evident that construction proceeds without interruption. The optional phase of construction takes four periods and the committed phase takes four periods. Figure L-63 reproduces the costs in each period of Figure L-58. Column D identifies the 0-based period, and the costs begin in period 25 for cohort 25. Column E is just the period escalation factor, i.e., one plus the escalation rate, all raised to the number of periods. Column F has the one-time sunk cost for planning, just the escalation factor times the capacity times the planning rate. (This and the other formulas here are as in the description of columns F through I on page L-70.) In column G, rows 15 through 18, the formula is identical except that the formula uses the construction cost rate instead of the planning rate. The formula appears in the equation window at the top of the page. In column G, row 11, the formula is the same as that in rows 15 through 18, except multiplied by four because all the optional construction costs are "pulsed" into the first period. The reader may now compare the cumulative costs in column H with the costs in row 465 of Figure L-58. Because there is only one active cohort, these costs match those in row 457.

This concludes the description of the new resource capital costing and planning flexibility representation in the portfolio model. This section described the portfolio model's concept of planning and construction flexibility, including features such as market addition of plants, sunk costs for planning, and pulsed construction costs. It presented the three ranges in the workbook that implement new resource additions and planning flexibility. In illustrating the range that specifies the resource plan, it provided some background on the reasons why the Council chose planning commitments to describe the plan and how they selected the planning intervals. Finally, the section reproduced the costs associated with a cohort, using special UDFs that identify the construction status and costs of any specific cohort.

Two areas of modeling are conspicuously absent: summarizing the costs and development of the decision criteria that drive both the DSI and the planning flexibility UDFs results. The present value calculations are in the following subsection. The important issue of decision criteria has its own section following this one.

G16 = =E16*$C$3*$C$5

	B	C	D	E	F	G	H
2	escalation	-0.0008568	per quarter				
3	cap	610	MW				
4	planning rat	0.00149	$M/MW/per^2				
5	constr rate	0.00292	$M/MW/per^2				
6							
7		Column	Period	escl	incr plng	incr cnstr	cum
8					(M$)	(M$)	(M$)
9		AO	23				0.000
10		AP	24				0.000
11		AQ	25	0.9788	0.890	6.973	7.864
12		AR	26	0.9780			7.864
13		AS	27	0.9771			7.864
14		AT	28	0.9763			7.864
15		AU	29	0.9754		1.737	9.601
16		AV	30	0.9746		1.736	11.367
17		AW	31	0.9738		1.734	13.101
18		AX	32	0.9729		1.733	14.834
19		AY	33	0.9721			14.834
20		AZ	34	0.9713			14.834
21		BA	35	0.9704			14.834

Figure L-63: Costs in Each Period

Present Value Calculation

Previous sections have presented the concepts, equations, and formulas for computing the cost of each source of load and energy. Loads, including smelter loads, and resources such as thermal generation, hydrogeneration, conservation, contracts, and renewables -- all of these produce period costs. As seen in the last section, the portfolio model treats the fixed costs associated with capital investment, fuel, and O&M as real levelized period costs, as well. The final step in the portfolio model is to compute the total net present value from these period costs.

The net present value calculation appears in column {CV}. For example, the net present value cost for the on-peak non-DSI loads is in row {323}:

=8760/8064*NPV(0.00985340654896882,$R323:$CS323)*(1+0.00985340654896882)

This equation has three multiplicative terms. The first term is the ratio of the number of hours in a calendar year to the number of hours in a standard year. As described in section "Single Period," all period calculations assume standard months, quarters, and years. This first term performs the cosmetic task of converting dollars per standard year to dollars per year. The portfolio model does not concern itself with the exact number of on- and off-peak hours in each quarter.[27]

The second and third terms discount the period costs to the first period. The Excel net present value function NPV discounts cash flows to the period immediately *before* the first cash flow. The third term merely moves it up to the first cash flow. The discount rate is the discount per quarter, given the four percent discount per year.

This formula represents an unfortunate instance where data appears in code. The ratio of hours in a calendar year to a standard year is a constant and might be appropriate for a formula like this one. The discount rate, however, should never appear in a formula like this. This formula is a vestige of an earlier version of the portfolio model.

The formulas in {CV1063} and {CV1065} total the net present value cost contributions for energy use and production and for the fixed costs of new resources. The only resource that does not contribute to the total net present value cost is the supply curve associated with commercial use of hydrogeneration. The section "Price-Responsive Hydro" explains this convention.

Cell {CV1065} is a Crystal Ball "forecast" cell. It has the default sky-blue color of such cells. Crystal Ball tracks the values in forecast cells and makes them available to the OptQuest add-in. One may think of these cells as the primary "output" of the worksheet.

Below the formulas in cell {CV 1065}, the reader will recognize several cells as risk measures. In fact, it is not possible to determine the risk associated with the distribution of net present value costs from a single future. Instead, after all 750 futures have been simulated and their total system costs calculated by this workbook, and an Excel subroutine uses Crystal Ball functions to recover the 750 values for {CV 1065}, stored in memory. The subroutine then calculates risk measures such as TailVaR_{90} and places the resulting values in Crystal Ball "forecast" cells for use by that application. The section "Using the Regional Model" explains this process.

Decision Criteria

The previous section introduced the concept of decision criteria. Both the DSI smelter startup/shutdown decision and the construction decision for new electric power resources rely on decision criteria. Conservation also uses a decision rule to determine whether to buy more conservation than short-term cost effectiveness would suggest, and if so how much.

This section begins with background on what decision criteria are, how the regional model uses them, and some of the discoveries and considerations that went into selecting the decision criteria. The specific criteria for new resources, conservation, and DSIs then

[27] As explained at the beginning of the section "Single Period," if it became important to do so, a user could recover the exact calendar year costs by applying to each standard quarter the weighting of on- and off-peak hours in that quarter relative to the other quarters in the year.

each have their own sections. The sections describe the particular aspects of each criterion and trace the formulas that implement them though the sample workbook.

Background

The defining characteristic of planning under uncertainty is imperfect foresight. With perfect foresight, there would be no risk. A risk model must therefore incorporate at least two special features. First, a risk model must have the ability to add resource capacity or other course of action without the benefit of perfect foresight. Most production cost or system simulation models capable of capacity expansion use techniques that assume perfect foresight. For example, these models may remove resources that do have sufficient value in the market to cover forward going fixed costs or add resources that would make a risk-adjusted profit in the market. An iterative process removes or adds resources until all new resources would just cover their risk-adjusted costs. Alternatively, a capacity expansion model may choose a capacity expansion schedule that minimizes cost. Both of these approaches must determine future hourly costs and prices to feed back to the capacity expansion algorithm. This feedback determines whether some adjustment to the construction schedule is necessary. If the model modifies the schedule, of course, the model must re-estimate future costs and price changes. The process repeats until the model finds a solution. These estimates of future costs and prices represent perfect foresight regarding how resources, costs, and prices affect one another. Perfect foresight, however, is contrary to the principles of risk analysis.[28]

Second, a risk model that incorporates capacity expansion must have a decision rule that determines whether to build or continue building. Because a risk model cannot use perfect foresight, the value of this criterion must use information about the current situation or about the past. Of course, different resources may use different criteria. A good test of a decision criterion, as it turns out, is whether it reduces cost and risk.

A decision criterion need not be perfect. The assessment of the value of planning flexibility relies on how well a resource plan performs when circumstances *do not* materialize as planned. As long as the decision criterion adds resources and makes wrong forecasts (from the standpoint of perfect foresight) in a realistic manner, it could be deemed adequate.

All decision criteria implement the concept of causality. Decisions to build, shut down or start up smelters, and so forth rely on the strict past (prior periods). That is, the logic that controls construction progress or smelter operation references the criterion value in the *prior* period. The reasons appear above in the section "Concept Of Causality," beginning on page L-58.

All decision criteria formulas are in the Twilight Zone, rows {223} through {316}. The model updates these before beginning any period calculations and with any iterations of

[28] A peculiar side effect of perfect foresight models is they often lead decision makers to rely on the market. Capacity expansion models with perfect foresight add power plants precisely when they have greatest value. Following this approach, however, leads to market prices that match the fully allocated cost of the capacity expansion alternative or to long-term marginal expansion costs that match market prices. Given that the decision maker is no better building a plant than she would be if she purchased firm power in the market, there is little incentive to incur the considerable risks and challenges of building.

the RRP algorithm. The reason this is necessary is that some intermediate values that contribute to decision criteria will change with each iteration, such as power plant value when electricity price changes.

New Resource Selection

The section "New Resources, Capital Costs, and Planning Flexibility" describes how the model uses a decision criterion to halt or continue activity during the earlier phase of construction. The model incorporates such behavior to permit the valuation of planning flexibility.

Given how important the decision criterion is to assessing planning flexibility, it is natural to ask what alternatives exist and why the Council chose this particular decision rule. The first rule implemented in early versions of the portfolio model was valuation using forward prices. One concern that arose when consideration turned to valuing conservation is that plans with more conservation often received substantial value by virtue of "being there" when high market price excursions occurred.[29] Resources that used only valuation in the market could only react to these excursions; often completing construction after the excursion subsided. Although this may help describe behavior during the 2000-2001 energy crisis, a more experienced market will probably pay careful attention to physical resource adequacy in the future. Moreover, when a resource-load balance criterion replaced the market valuation criterion in the portfolio model, the feasibility space and its efficient frontier displayed reduced risk at no increase in cost. Resource-load balance does a better job of predicting the need for resources.

Resource-load balance alone, however, presents some problems as a decision criterion. An examination of particular futures revealed unrealistic behavior. Resource-load balance ignores economics completely. Given a future with high gas prices, for example, the portfolio model would be as likely to develop a gas-fired turbine as a coal plant if it has a choice between the two. Consequently, the criterion in the final version of the portfolio model gives consideration first to resource-load balance and then uses plant valuation to make the resource choice.

For conventional thermal resources and wind generation, the approach that performed best incorporates information about resource-load balance and forward prices for fuel and electricity prices. Specifically, the model uses a three-year average of load growth and any change in resource capability to determine when in the future resource-load balance would cross below a given threshold. The selection of the threshold is itself part of the choice the model makes to minimize cost or risk. That is, the threshold is in a Crystal Ball decision cell, under the control of the optimizer. In each simulation period and for each resource candidate, the model determines whether the crossover point is less than the construction time required for that resource.

[29] This value comes not only from the advantageous resource-load position, but also from price moderation due to the additional resources. This raised the question of whether other resources, built to maintain some reserve margin, would not also benefit plans. This turns out to be the case, although – as the section "Conservation Value Under Uncertainty" describes – conservation often can serve this role a lower net cost.

If the model needs a resource to meet anticipated future load, the criterion consults pertinent forward prices for each resource. For example, for a gas-fired power plant, the model would estimate the plant's value from forward prices for electricity and natural gas and compare those to capital and other fixed costs to determine whether the plant would pay for itself. If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues.

The model uses forward prices for electricity, natural gas, and other commodities, but it cannot use perfect foresight. Consequently, the model estimates forward prices using the assumption that futures and forward prices closely track current prices. This relationship is apparent in data for many commodities for which storage of the commodity is limited, including natural gas and electricity. For example, for gas-fired new resources, average commodity price for natural gas and electricity over the last 18 months is the forecast of those forward prices. This reflects the fact that it often takes awhile for perceptions about long-term prices to change.

Model Representation

In the workbook, we will trace the decision criterion for the CCCT backward from the final value. This section will also point out any differences with the decision criteria for the coal plant, SCCT, demand response, and wind. Demand response and wind, in particular, merit a paragraph each at the end of this discussion.

The CCCT new capacity UDF in cell {AQ455} points to the decision criterion in cell {AP302}. The formula in cell {AP302} is as follows

```
=IF(AP$297<$O303,IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1),-1)
```

This formula first checks to determine whether the forecasted crossover point for resource-load balance is less than the lead time for construction of the CCCT. If that is false, then the decision criterion is set to -1 (no-go). Otherwise, the formula sets the value to +1 (go) if the CCCT either is expected to make money in the market or is the least cost resource among the available alternatives and to –1 otherwise. It may be useful to parse the formula to better understand it. The outside "if statement"

```
=IF(AP$297<$O303,...,-1)
```

checks the forecasted crossover point in cell {AP297} against the number of periods for construction in cell {O303}. If the lead time for construction is greater than the forecasted crossover time, the formula returns to –1 indicating that construction is unnecessary and undesirable. Otherwise the inner if statement is executed

```
IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1)
```

the first condition in the OR test

```
AP253>=0
```

checks whether the CCCT makes money in the market. The second condition in the OR test

```
AP253>(AP$282-$R$283)
```

checks to see whether the cost of the CCCT is within some small interval, specified in {R283}, of the minimum cost among all resources, calculated in cell {AP253}. There are four key variables in this formula:

- Construction lead time
- Neighborhood of the minimum cost
- Forecasted Energy Margin Crossover Point
- Market Viability

The first two variables are easy to describe. The construction lead-time is the sum of the periods for optional and committed construction:

```
=C455+D455+E455
```

The first term in the sum points to the number of periods for planning and siting, but that value is zero for all new resources in the regional model.

The test with the minimum uses a neighborhood for technical reasons. The model does not test whether the cost of the CCCT is *exactly* the minimum cost among all resources, because of the problem associated with comparing any two real numbers in computer code. That is, some manipulation, e.g., finding the minimum of a set of numbers, may corrupt the minimum by an infinitesimal amount. This corruption could render the comparison invalid. To avoid this situation, the formula instead checks whether the resource is within some very small neighborhood of the minimum.

The remaining two variables, Forecasted Energy Margin Crossover Point and Market Viability, are more complex and merit their own sections. These are the next two sections.

Forecasted Energy Margin Crossover Point

The forecasted crossover point ({AP297}) is an estimate of when requirements will surpass resources. The calculation of load requirements for this estimate, however, includes the addition of a user-specified, energy reserve margin target. This user-specified target is under the control of the optimization software through its assignment to a Crystal Ball decision cell.

The formula in cell {AP297} is the following

```
=IF(AP295<AP296,(AP295-$T$3)*12/(AP296-AP295),IF(AP295<$T$3,-1,100))
```

This formula checks to see if resource net of total load ({AP295}) has declined over the last three years. If so, it uses the rate of decline to determine how many periods will pass before resources decline below the load plus energy reserve margin. If not, it checks whether resource net of total loads is below the energy reserve margin target ({$T$3}). If so it returns the value -1. Otherwise it returns the value 100. These values are the number of periods before crossover is anticipated to take place. Negative one (-1), of course, will be less than the construction time for any resource and will therefore result in a positive value for the decision criterion, other factors permitting. The value 100 exceeds the construction time of any resource and would typically result in a negative decision criterion value.

It can of course happen that the balance ({AP295}) has declined over the last three years but is already below the target energy-reserve margin. In this case, the formula will return a negative number. This number is a back-cast of the number of periods in the past that the balance slipped below the target. Any negative value signals that construction is necessary.

The cell {AP295} computes resources net of loads by adding the various terms immediately above that cell in the worksheet, as shown in Figure L-64. The model updates these for the new values under this future. (The Figure L-64 also demonstrates the situation described above where the balance has declined but is already below the 3000MW target energy reserve margin, and the value returned is negative.)

The load estimate in cell {AP289} is the hydro year's average, weather-corrected non-DSI load (the range {AL126: AO126}), plus the DSI load in the final period. The model's weather corrected load is simply the load, less the stochastic part that represents weather variation in the winter and summer. The reader will find a complete discussion of load representation in Appendix P.

AP295 = =SUM(AP289:AP294)

	Q		AP
287			
288	Reserve Margin, ver 2: annual energy (MWa)		
289	loads		-21000
290	contracts, net import		252
291	conservation		613
292	new capacity		0
293	variable capacity thermal resources		1,973
294	existing resources		20895
295	**total (MWa)**		2733
296	**total (MWa) three year's prior**		3091
297	periods to hit target reserve margin		-9.0

Figure L-64: Resources Net of Loads

Net import contract energy in MWa (cell {AP290}) is given by

=4/7*AVERAGE(AL84:AO84)+3/7*AVERAGE(AL88:AO88)

This is merely the average of contracts (MWa) over the previous four quarters on peak (row {84}) and off peak (row {88}), weighted by the respective number of on- and off-peak hours in the standard quarters.

Conservation in MWa (cell {AP291}) is

=(SUM(AL377:AO377)+SUM(AL386:AO386)+SUM(AL741:AO741)+SUM(AL749:AO749))/(4*(1152+864))

This formula references the lost opportunity (rows 377 and 741) and discretionary (rows 377 and 741) conservation energy in MWh on- and off-peak over the last four quarters. The average MW are then this sum, divided by the hours in a standard year, 4*(1152+864).

New capacity in MWa (cell {AP292}) is

=AO455+AO469+AO483+0.3*(AO509+AO519)

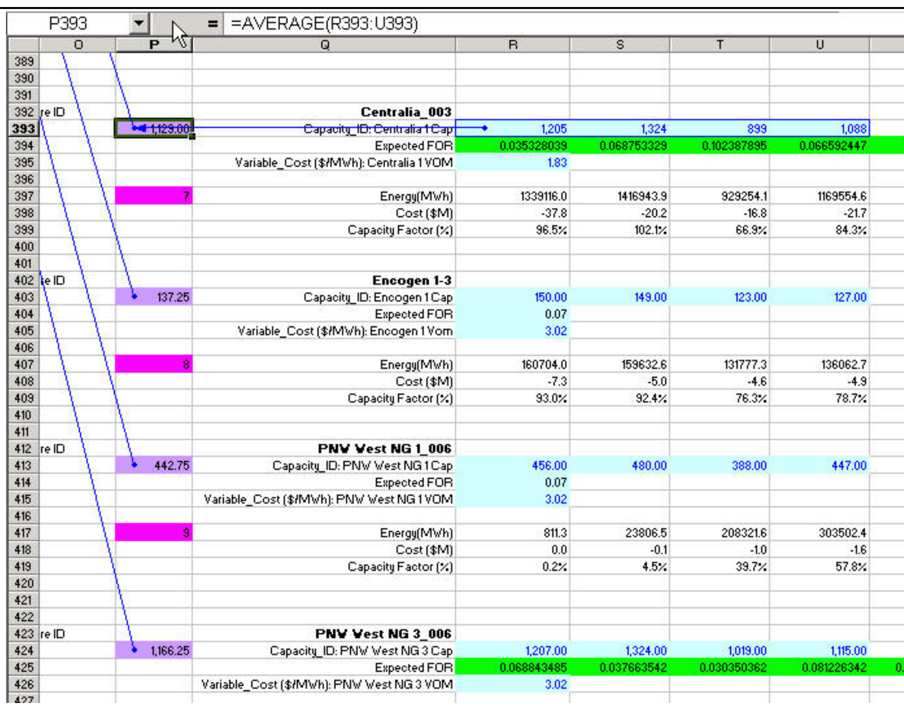
The CCCT, SCCT, and coal-fired capacity in the last period is added to 30 percent of the two wind unit capacities. Energy from the wind units must be discounted, because of the low availability of wind. Missing here is any capacity from demand response (DR). DR is considered an emergency resource in these studies and its expected energy contribution is nil.

"Variable capacity thermal resources" (cell {AP292}) is a misnomer. In fact, there is a substantial amount of renewable (wind) energy in this sum. This capacity changes from year to year. It requires summing the annual average capacity of those resources.

=SUM(AVERAGE(AL345:AO345),AVERAGE(AL355:AO355),1497+0.3*(AVERAGE(AL536:AO536)-1497),AVERAGE(AL610:AO610))

In this workbook, developed before the draft plan, three generic thermal resources are retired over 10 years. The average capacity for each appears as the first, second, and forth terms in this sum. Must run resources, the third term, include thermal resources that stay at the same capacity (1497 MW) over this period and wind resources that increase in capacity. There is an error in this formula. The energy of the wind is discounted twice, once in the values reported in the range {AL536:AO536} and again by the formula. In the version of the model used to create the final plan, there are no thermal unit retirements, and the double-discounting does not take place. The cell is also labeled more accurately, "variable must-run firm energy."

The "existing resources" (cell {AP293}) are those resources that have annual energy production that is constant over the study. Hydro generation energy is included at the critical water amount. The formula in cell {AP293} merely adds the critical-water hydro


P393 = =AVERAGE(R393:U393)

	O	P	Q	R	S	T	U
389							
390							
391							
392	re ID		**Centralia_003**				
393		1,129.00	Capacity_ID: Centralia 1 Cap	1,205	1,324	899	1,088
394			Expected FOR	0.035328039	0.068753329	0.102387895	0.066592447
395			Variable_Cost ($/MWh): Centralia 1 VOM	1.83			
396							
397		7	Energy(MWh)	1339116.0	1416943.9	929254.1	1169554.6
398			Cost ($M)	-37.8	-20.2	-16.8	-21.7
399			Capacity Factor (%)	96.5%	102.1%	66.9%	84.3%
400							
401							
402	re ID		**Encogen 1-3**				
403		137.25	Capacity_ID: Encogen 1 Cap	150.00	149.00	123.00	127.00
404			Expected FOR	0.07			
405			Variable_Cost ($/MWh): Encogen 1 Vom	3.02			
406							
407		8	Energy(MWh)	160704.0	159632.6	131777.3	136062.7
408			Cost ($M)	-7.3	-5.0	-4.6	-4.9
409			Capacity Factor (%)	93.0%	92.4%	76.3%	78.7%
410							
411							
412	re ID		**PNW West NG 1_006**				
413		442.75	Capacity_ID: PNW West NG 1 Cap	456.00	480.00	388.00	447.00
414			Expected FOR	0.07			
415			Variable_Cost ($/MWh): PNW West NG 1 VOM	3.02			
416							
417		9	Energy(MWh)	811.3	23806.5	208321.6	303502.4
418			Cost ($M)	0.0	-0.1	-1.0	-1.6
419			Capacity Factor (%)	0.2%	4.5%	39.7%	57.8%
420							
421							
422							
423	re ID		**PNW West NG 3_006**				
424		1,166.25	Capacity_ID: PNW West NG 3 Cap	1,207.00	1,324.00	1,019.00	1,115.00
425			Expected FOR	0.068843485	0.037663542	0.030350362	0.081226342
426			Variable_Cost ($/MWh): PNW West NG 3 VOM	3.02			

Figure L-65: Resources with Constant Annual Energy Availability

energy, a user-specified constant, and the total capacity for the fixed-capacity resources. The total fixed capacity in cell {I289} merely points to averages of energies across the hydro year for each relevant plant, as illustrated in Figure L-65.

Market Viability

Returning to the beginning of this section, “Model Representation” on page L-83, the last variable in the decision criterion for new resources is market viability (cell {AP253}). The market viability test is made in a set of rows just above those where the worksheet determines resource-load balance. As explained above, the intent is to simulate forward curves values and calculate whether or not the value of the resource in the market would cover its fixed costs. Figure L-66 shows the formula for this cell.

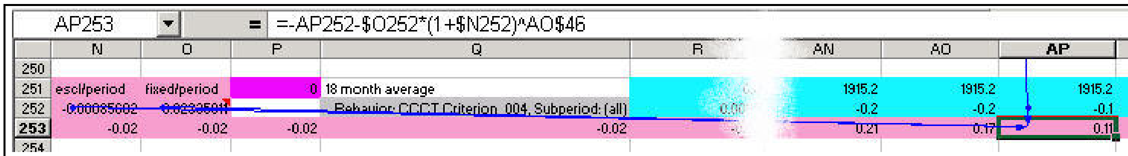


Figure L-66: The Net Market Value Test

The first term in the formula {AP252} is the value of the CCCT in the market. It contains a call to the spread option UDF described in the section “Thermal Generation,” above, which returns the value (2004 $M) in the market. (See Figure L-67.) This call is identical to the one for the generic CCCT itself with three exceptions: the size of the plant is 1MW, the electricity price is an 18-month average of flat electricity prices, and the natural gas price is also an 18-month average. The market viability valuation uses equal 1MW capacities for all new resource candidate to normalize the value to dollars per MW. The 18-month averages of past prices, as explained above, is used as a surrogate for forward prices and to reflect the time necessary for owners to develop confidence in the forward prices. The development of these stochastic prices appears in Appendix P.

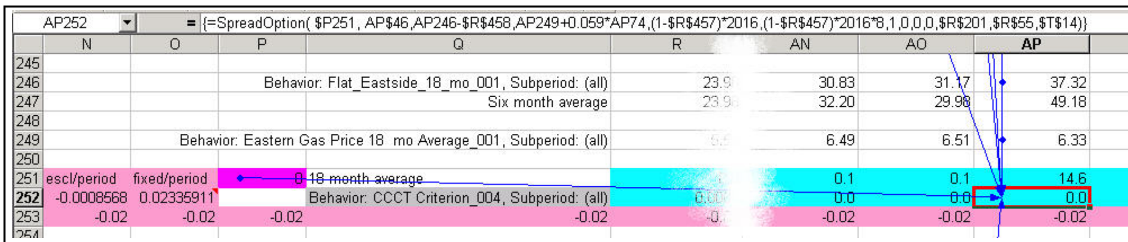


Figure L-67: Value of Plant in Market

The second additive term in formula {AP252}, \$O252*(1+\$N252)^AO\$46, is the fixed cost per MW. (See Figure L-66.) The cell {\$N252} references the escalation rate per period for CCCT fixed costs, and the cell {AO\$46} is the zero-based period index. The formula for 2004\$ fixed cost per MW in cell {\$O252} is

=SUM(D455:E455)*I455

which sums the number of optional and committed construction periods and multiplies it by the real levelized millions of dollars per period squared. The cost for planning periods, which are zero anyway, should not be included as they are sunk cost for the plan.

For demand response, the treatment is identical to the CCCT decision criterion with the following exceptions. Demand response (DR) is modeled as a thermal unit with a dispatch cost of $150/MWh (2004$). Because DR programs require little time to implement, they can respond more quickly to changing circumstances. Their relatively small set-up cost minimizes the risk of having the opportunity disappear. For this reason, the DR decision criterion does not use an 18-month average electricity price, but uses the period price instead. Note also that in both the draft and final plans, the plans hard-wire the plan for DR development (row {7}) rather than placing it under the control of the optimizer. The model still uses the decision criterion logic.

For wind generation, the treatment is identical to the CCCT decision criterion with the following exceptions. The value of wind in the market (cell {AP$277}) is

```
=2016*0.3*(AO$506-AP$247)/1000000
```

As before, the implied capacity is 1MW. The value in 2004 $M is then just the energy times the market price adjusted for any costs. The energy is 1MW times the number of hours in the period, times the capacity factor. The adjusted market price is the six-month average of flat electricity prices (cell {AP$247}), less the net of integration cost, production tax credit, green tag credit, and variable O&M (cell {AO$506}). The model uses a six-month average for electricity price instead of the 18-month average because the Council believed that, with the shorter construction cycle for wind, owners would want to respond more quickly and would not take as much time to build confidence in their lower dollar commitment to the more modular wind units. This represents an approach to averaging past prices that fall between that of DR and the thermal resources.

This concludes the discussion of decision criteria for new resources. One shortfall of these criteria is that they include the full fixed cost of construction irrespective of where plants are in their construction cycle. That is, forward-going construction decisions should treat costs associated with past construction as sunk cost. Modeling this economics would probably require a significant revision to the new capacity-planning flexibility UDF, as such detail must be tracked by cohort. It might make for even more realistic behavior, however.

Conservation

Conservation uses a decision criterion somewhat different from that for new resources. Conservation can introduce thorny problems, like cost shifting for ratepayers and revenue recovery for load-serving entities. Consequently, special regulatory or administrative intervention is typically necessary. Cost effectiveness has been the standard that administrators use to deem the type and amount of conservation to pursue.

Because conservation uses a cost-effectiveness standard, a criterion that resembles such a standard seems appropriate. However, the challenges in constructing a cost-effectiveness criterion are several.

- Cost effectiveness levels change over time as market prices for electricity change, although administrators tend to base them on long-term equilibrium prices for electricity. Models that estimate equilibrium prices for electricity are sensitive to commodities that have been less volatile than electricity prices, such as natural gas price. Regardless, cost-effectiveness standards are subject to uncertainty and change depending on the particular future.

- Because they are often determined administratively, they change more slowly than commodity prices. Moreover, the time between changes in efficiency standards and when the conservation measure starts to contribute can be a year or more, while load-serving entities develop their budgets and ramp up programs. Thus, there is considerable lag time between changes in commodity prices and changes in conservation energy rate of addition.

- Some types of conservation become institutionalized, such as that associated with new codes and standards for building construction. Once the codes pass into law, the corresponding measures are no longer directly subject to the cost-effectiveness standard. Thus, the decision criterion for this kind of conservation is "sticky downward." It does not decrease, and it increases only when the cost-effectiveness standard passes the previous "high-water mark."

- The NW Power Act requires that the power plan assign a ten percent cost advantage to the acquisition of conservation. By using a criterion that accessed the supply curve as a level at least 10 percent higher than a market-based cost-effectiveness standard, the portfolio would accommodate this requirement.

- A long-standing Council objective has been to understand what value there may be in sustained, orderly development of conservation. Is there any advantage to this policy over the sustained, orderly development of any other resource? Is there any cost or risk advantage to developing more conservation than a conventional cost-effectiveness standard would suggest?

These considerations drove the design of the decision criteria for conservation. The decision criterion takes the form of a price. This price and a supply curve determine how much conservation to develop in a given period. Both lost-opportunity and discretionary conservation[30] criteria are the sum of two terms. The first term approximates the cost-effectiveness standard. This is a "myopic" estimate of cost effectiveness, which depends on the specific future and changes over time in that future. The second term determines how much additional conservation to deploy compared to the cost-effectiveness level. This second term, a price adjustment, is under the control of the logic that helps the portfolio model find the least-cost plan, given a fixed level of risk.

[30] The description of these classes of conservation appears in Chapter 3

Lost Opportunity Conservation

Lost opportunity conservation modeling uses the supply curve UDF described in the section "Conservation," beginning on page L-44. In the column {AQ}, the model accesses the lost-opportunity conservation supply curve using the price {AP$233+$R$375}. (See Figure L-68.) The first term represents the cost-effectiveness standard. The second term, {$R$375}, merely points to a cell which, in turn, references a Crystal Ball decision cell. The optimizer can change the value in the decision cell to specify the plan. Our focus here will be the cost-effectiveness measure in cell {AP$233}.

Note that the formula in cell {AQ377} also accesses the response to load factor in cell {AP240}. This is not part of the decision criterion. This appendix addresses the response to load factor in section "New Resources," beginning on page L-99.

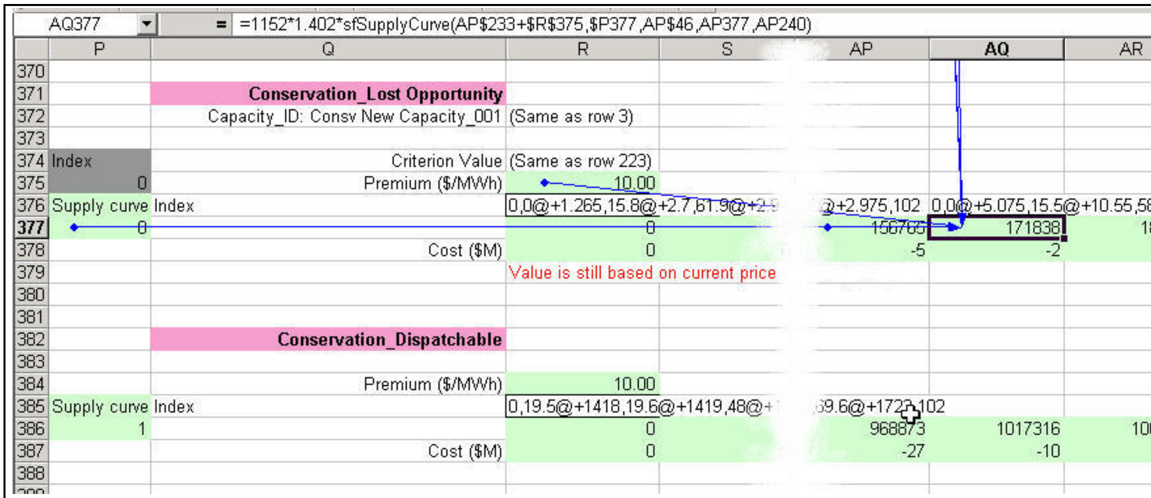


Figure L-68: Criterion References for Conservation

The formula in cell {AP$233} clearly does nothing more than find the highest value in the preceding row since the beginning of the study:

=MAX($Q$232:AO232)

This facilitates the "sticky downward" behavior. The value of the decision criterion will always be the highest value the preceding row achieves. As explained above, this represents such things as market transformation and the implementation of codes and standards.

Columns in the preceding row uses a fairly complicated formula. For example in column {AO}, the formula is

=MAX(0,20-AN46)*$Q$232/20+MIN(20,AN46)*
AVERAGE(OFFSET($Q$230,0,MAX(0,AN46-19),1,MIN(AN46+1,20)))/20

(Column {AO} is the last column referenced by cell {AP$233}.) This formula computes a five-year (20 period) average of the electricity price values in row {230}. The electricity price values in row {230} are weighted by the amount of conservation on- and off-peak. We will return to them shortly.

The reason for the complexity of the formula is that a single cell is providing an estimate of electricity prices in the past. For many prices and other stochastic variables, the worksheet contains explicit values for the time before the beginning of the study wherever necessary. For such a long reach into the past, however, a different approach was necessary. This formula uses the average of electricity prices over the past 20 periods, unless the beginning of the averaging interval is less than 20 periods in the past. In the latter case, it uses the value in cell {$Q$232} to form a weighted average, giving the value in {$Q$232} to as many periods as precede the beginning of the study.

The electricity price values in row {230} are of the form

```
=AP$207*1.402*4/7 + AP$219*0.465*3/7
```

This weighs the on-peak electricity price west of the Cascades by the expected on-peak conservation savings (1.402) and the fraction (4/7) of hours on peak during a standard quarter. The second term is the off-peak contribution, calculated in an identical fashion. Much of the load and conservation potential lies west of the Cascades.

Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection "Supply Curves" of the section "Resource Implementation and Data," below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of the weighting factor 1.402 appears in that section.

Discretionary Conservation

Returning to Figure L-68 and the worksheet, the user finds a near-identical supply curve formula for discretionary conservation in cell {AQ386}. As in the lost-opportunity case, the supply curve access price is the sum of two values, the cost-effectiveness standard and value that references a Crystal Ball decision cell, which is under the control of the optimizer.

The cost-effectiveness calculation is different from that for lost opportunity. In cell {AP235}, which cell {AQ386} references, we find

```
=AVERAGE(AH230:AK230)
```

Because discretionary conservation is available for implementation at any time, codes and standards are not necessary to capture it. Utilities can wait until prices and the cost-effective standards increase before taking action. This formula averages the conservation-weighted electricity price from not the immediate past year, but the *preceding* year, to obtain the cost-effectiveness level. The reason for looking back two years is to reflect budgeting delays. That is, utilities usually set a budget earlier in the year for the following year and follow that schedule the following year. When they prepare that budget, however, they would be looking back over the preceding year.

DSIs and Smelters

As with thermal plants, the model uses prices for aluminum and electricity over the preceding 18 months as a surrogate for forward prices. These inform the decision to shutdown or start up each of the seven smelters in the region. (See section "DSIs" for a description of the algorithm for smelter operation.)

The UDF for smelter capacity in cell {AQ327} references the 18-month average of flat electricity prices in row {227} and the 18 month average of aluminum prices in row {270}. These averages are straight forward. The model of electricity prices and aluminum prices appears in Appendix P.

This section addressed decision criteria. It reviewed some of the experiences that led to the final selection of decision criteria for new resources, and it explained the calculation of resource-load balance and market viability of resources. It also explained the thinking behind, and formulas that implement, decision criteria for conservation and smelters.

With an understanding in principle of how various ranges in the worksheet function, this appendix now turns to the detailed representation of plants and conservation, including the model's data.

Resource Implementation and Data

This section begins with the procedure by which existing regional resources are aggregated into the thirty plants in the regional model. It dedicates extra sections to the treatment of the region's independent power producers and system benefit charge (SBC) wind. It then addresses the candidate new resources, such as the generic CCCT, coal, and wind plants used for capacity expansion. Because forced outages are really an aspect of the future, detailed description of their modeling appears in Appendix P, although the key descriptive statistic, the effective forced outage rate (EFOR), appears in this appendix. Conservation is a candidate for meeting new requirements, and there is a section on data for the conservation supply curves and on conservation energy weighting assumptions. The section concludes with documentation for the contract data used in the model.

Existing Resources

The portfolio model consolidates regional resources into surrogates with identical technology and similar operating characteristics. Besides simplifying the worksheet, this reduces the computation time.[31] Each surrogate has regional plants of identical fuel type

[31] Each UDF call requires approximately 300 microseconds. This execution cost appears to be largely independent of the amount of VBA code behind the UDF. The execution cost is associated primarily with Excel's handling of the function call. Each plant in the regional model occupies 80 periods and two subperiods. This results in 48 milliseconds per plant or about 21 plants per second. This computational burden does not include the calls to other UDF's, such as those for planning flexibility or smelter operation. If a worksheet requires one second to compute, a thousand plans under 750 futures -- a typical requirement for the construction of a feasibility space -- would require approximately 8.7 days of computation time. Although the regional model wound up with about 30 surrogate plants, distributed processing across 10 machines reduced computation time to one day. Although modeling each of the 115 plants individually is feasible in principle, it would have increased these runtimes fourfold with questionable benefit.

and technology (CCCT, SCCT, etc.). Surrogates also represent plants of similar variable operating cost, which plant heat rate largely determines. Surrogates have a heat rate equivalent to the capacity-weighted heat rate of their constituents.

Monthly availabilities for the surrogate are the sum of the regional plants' monthly availabilities. The monthly availability of existing regional power plants appears in Figure L-69 and Figure L-70 [**7**]. Genesys simulations generate the monthly availabilities [**8**]. The simulations rely on the database that the Council uses to populate its Aurora model. These availabilities reflect maintenance outages but not forced outages. The reference for forced outage data is [**9**]. The model captures forced outages through a stochastic variable or explicit capacity de-ration. (See Appendix P and below.)

The characteristics of the surrogate plants appear in Figure L-71[**10**]. The quarterly availabilities are averages of the corresponding monthly availabilities. Forced outage rates reflect forced outage rates of the constituent plants. For some of these plants, the model uses capacity duration to reflect forced outages. The policy for determining whether to use stochastic forced outages or capacity de-ration is that larger existing plants use stochastic forced outages. Smaller existing plants contributed little risk. Modeling stochastic forced outages for new plants represented a challenge not attended to by the regional model. In particular, the reliability of an ensemble of plants is better than that of a single plant. As the model added capacity, either the forced outage rate characteristics of the ensemble would have to improve, or the model would have to provide each cohort with its own stochastic forced outage schedule. Both of these approaches presented a considerable programming challenge for questionable benefit. This version of the regional model, therefore, takes the more simplistic approach.

In the workbook, the first on-peak resource listed is a surrogate resource, "PNW West NG 5_006." (The meta-model Olivia generated these names, and the "006" has no particular significance. See section "Olivia" below for information about this model.) In Figure L-72, auditing reveals the references for cell {AQ 339}. This cell contains the UDF for computing energy for a thermal resource. (See section "Thermal Generation.") Above, this appendix has described most of the references. The following, however, are noteworthy. First, the UDF is referencing the stochastic forced outage rate in cell {AQ 336}. The model uses this forced outage rate to modify the assumed availability of the plant. Second, the seasonal availabilities for this surrogate plant are evident in row 335, columns R through U. The formula cycles among these four availabilities. The cycling assures proper representation of seasonal variation and differences due to maintenance.

The regional model represents other thermal surrogate resources similarly. Must-run resources are an exception. The energy and value for the must-run units are simple to calculate because energy is uncorrelated with market price. The value is simply the market price of electricity times the energy. In addition, because must-run resources include system benefit charge (SBC) wind generation, and the wind capacity increases over time, the capability references do not cycle as with thermal resources. Instead, the UDF references typically point to the capability in the same period. SBC wind is the subject of the next section.

Unit Name	Alternative name/description	Aggr_Unit	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
			(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Bailey (Clatskanie GT)	Alden Bailey	PNW West NG 7	10	11	11	11	11	11	10	9	9	9	10	10
Beaver 1-7	Beaver	PNW West NG 5	475	487	498	504	505	500	435	370	364	359	469	468
Beaver 8	Beaver 8	PNW West NG 6	23	23	24	24	24	24	22	20	19	19	22	22
Big Hanaford	Big Hanaford	PNW West NG 3	233	239	245	248	248	246	214	182	179	176	230	230
Biomass-One 1	Biomass One	Must Run	23	23	23	23	23	23	23	23	23	23	23	23
Boardman 1	Boardman	Boardman 1	556	556	556	556	556	556	467	379	379	379	556	556
Boise Cascade Medfor	Boise Cascade Medfor	PNW West NG 1	8	8	8	8	8	8	8	8	8	8	8	8
Boulder Park	Boulder Park	PNW East NG 6	24	24	24	24	24	24	24	24	24	24	24	24
Boundary GT	(emergency)	PNW Oil												
BP (Cherry Point) GTs	BP Cherry Point GTs	PNW West NG 7	69	70	72	73	73	72	66	59	59	58	68	68
Centralia 1	Centralia 1	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
Centralia 2	Centralia 2	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
Chehalis Generation Facility	Chehalis Generating	PNW West NG 3	489	501	513	519	520	515	448	381	375	369	483	482
Coffin Butte 1	Coffin Butte	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
Colstrip 1	Colstrip 1	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
Colstrip 2	Colstrip 2	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
Colstrip 3	Colstrip 3	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
Colstrip 4	Colstrip 4	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
Columbia Generating Station	Columbia Generating	Must Run	1170	1170	1170	1170	1170	1170	944	720	720	720	1170	1170
Combine Hills I	Combine Hills I	Must Run	12	11	17	22	24	32	7	10	8	7	7	11
Condon Wind Project Phase I	Condon 2001	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Condon Wind Project Phase II	Condon 2002	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Corrette	J.E. Corrette	Corrette	160	160	160	160	160	160	134	109	109	109	160	160
Coyote Springs 1	Coyote Springs 1	PNW East NG 3	208	215	221	226	226	223	192	163	159	156	202	203
Coyote Springs 2	Coyote Springs 2	PNW East NG 3	258	267	274	280	280	276	238	202	197	193	251	252
Crystal Mountain 1 &	Crystal Mountain 1 &	PNW West NG 6	3	3	3	3	3	3	3	3	3	3	3	3
D R Johnson Lumber (Riddle, Coge	Cogen II	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
Danskin	Danskin (Evander And	PNW So ID NG 2	83	86	88	90	90	89	77	65	63	62	81	81
Eastsound 4 & 5	Eastsound 4 & 5	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Encogen 1	Encogen 1-3	Encogen 1	151	154	158	160	160	159	138	117	115	114	149	148
Equilon GTs	Equilon GTs	PNW West NG 7	37	38	38	39	39	39	35	32	31	31	36	36
Everett Cogen 1	Everett Cogen	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
Finley	Finley	PNW East NG 6	25	26	26	27	27	27	24	22	21	21	24	24
Foote Creek	Foote Creek	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
Frederickson 1	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Frederickson 2	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Frederickson Power 1	Frederickson Power (	PNW West NG 1	259	265	271	275	275	273	237	202	198	195	255	255
Fredonia 1	Fredonia 1	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
Fredonia 2	Fredonia 2	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
Fredonia 3	Fredonia 3	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
Fredonia 4	Fredonia 4	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
Frontier Energy	(no match)	Waste Burner												
Georgia Pacific (Camas)	Georgia-Pacific (Cam	Must Run	47	47	47	47	47	47	47	47	47	47	47	47
Georgia Pacific (Wauna)	Georgia-Pacific (Wau	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
Georgia-Pacific (Bellingham) GTs	Georgia-Pacific (Bel	PNW West NG 7	9	10	10	10	10	10	9	8	8	8	9	9
Glenns Ferry Cogeneration	Glenns Ferry Cogener	PNW East NG 3	8	9	9	9	9	9	8	7	7	7	8	8
Goldendale Energy Ce	Goldendale Energy Ce	PNW East NG 2	229	236	243	248	248	245	211	179	174	171	222	223
Grays Harbor ICs	Hoquiam 1 - 5	PNW Oil	10	10	10	10	10	10	10	10	10	10	10	10
Hermiston Generating 1	Hermiston Gen 1	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
Hermiston Generating 2	Hermiston Gen 2	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
Hermiston Power Project	Hermiston Power	PNW East NG 1	581	600	617	629	630	621	536	454	443	435	564	566
ICT PP&L/Utah&Wyo to	ICT PP&L/Utah&Wyo to	Valmy	184	160	168	154	187	187	178	171	189	265	296	253
Jim Bridger 1	Jim Bridger 1	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 2	Jim Bridger 2	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 3	Jim Bridger 3	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 4	Jim Bridger 4	Bridger	173	173	173	173	173	173	145	118	118	118	173	173
Kettle Falls GT	Kettle Falls GT	PNW East NG 3	6	7	7	7	7	7	6	6	5	5	6	6
Kettle Falls ST	Kettle Falls	Must Run	45	45	45	45	45	45	45	45	45	45	45	45
Klamath Cogen Project	Klamath Cogeneration	PNW East NG 1	443	457	470	480	480	473	408	346	337	331	430	432
Klamath Expansion (GTs)	(no match)	PNW East NG 3												
Klondike	Klondike	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Libby 1 Champion	(retired)	Must Run												
Libby 2 Champion	(retired)	Must Run												
March Point 1&2	March Point	PNW West NG 3	132	135	138	140	140	139	121	103	101	99	130	130
Mariah	Mariah	Must Run	0	0	0	0	0	0	0	0	0	0	0	0
Marion Solid Waste 1	Covanta Marion	Waste Burner	9	9	9	9	9	9	9	9	9	9	9	9
MEAD	MEAD	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Morrow Power	Morrow Power	PNW East NG 6	23	24	25	25	25	25	21	18	18	17	22	22
Mountain View	Mountain View	PNW East NG 6	148	152	157	160	160	158	136	115	112	110	143	144
Nine Canyon	Nine Canyon	Must Run	14	12	20	25	27	36	9	11	10	8	8	12
Nine Canyon	Nine Canyon Expansio	Must Run	4	4	6	8	9	12	3	4	3	3	3	4
North Side	North Side	PNW East NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Northeast	Northeast 1 & 2	PNW East NG 6	62	64	66	67	67	66	57	48	47	46	60	60
Okanogan Co PUD ICs Ph 2	Okanogan Co. PUD ICs	PNW Oil	25	25	25	25	25	25	25	25	25	25	25	25
OR RPS/SBC Wind 03	OR RPS/SBC Wind 03	Must Run												
Pasco	Pasco	PNW So ID NG 2	40	41	42	43	43	42	38	34	34	33	39	39
Pine Products	(out of the mix)	Must Run												
Pocatello Waste 1	(lost)	Waste Burner												
Point Whitehorn 2	Point Whitehorn 2	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Point Whitehorn 3	Point Whitehorn 3	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Potlatch Corp 1-4	Potlatch Corp. 1-4	Must Run	53	53	53	53	53	53	53	53	53	53	53	53
Prairie Wood Products (Cogen 1)	Prairie Wood Product	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
Randolph Road 1- 20	Randolph Road 1- 20	PNW East NG 6	31	31	31	31	31	31	31	31	31	31	31	31
Rathdrum 1 & 2	Rathdrum 1 & 2	PNW East NG 6	162	168	172	176	176	174	150	127	124	121	158	158
Rathdrum Power Project	Rathdrum Pwr Proj	PNW East NG 2	223	231	237	242	242	239	206	174	170	167	217	218
River Road 1	River Road	PNW West NG 1	233	239	245	248	248	246	214	182	179	176	230	230
Rock River	Rock River	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
Roosevelt Landfill	Hill	Must Run	9	9	9	9	9	9	9	9	9	9	9	9
Rupert Cogeneration	Rupert Cogeneration	PNW So ID NG 2	8	9	9	9	9	9	8	7	7	7	8	8
Salmon 1 & 2	Salmon 1 & 2	PNW East NG 6	6	6	6	6	6	6	6	6	6	6	6	6
SDS Lumber ST	(unavailable)	Must Run												
Short Mountain	Short Mountain	Waste Burner	3	3	3	3	3	3	3	3	3	3	3	3
Simplot Cogen 1	Simplot Pocatello	PNW East NG 3	8	8	8	8	8	8	8	8	8	8	8	8
Skagit Co Waste 1	(retired)	Waste Burner												
SP Newsprint (Newberg)	SP Newsprint GT	PNW West NG 3	86	88	90	91	91	90	82	74	73	72	85	84
Spokane MSW 1	Spokane MSW	Waste Burner	21	21	21	21	21	21	21	21	21	21	21	21
Springfield ICs Phase II	Springfield Ph II	PNW West NG 6	10	10	10	10	10	10	10	10	10	10	10	10
Stateline	Stateline	Must Run	156	141	227	286	310	415	98	129	111	93	91	141
Steam Plant No 2 1	(retired)	Waste Burner												
Steam Plant No 2 2	(retired)	Must Run												
Sumas Energy 1	Sumas Energy	PNW West NG 3	116	119	121	123	123	122	106	90	89	87	114	114
Tacoma Landfill	Tacoma Landfill	PNW West NG 6	2	2	2	2	2	2	2	2	2	2	2	2
Tenaska 1	Tenaska Washington I	PNW West NG 3	231	236	242	245	245	243	211	180	177	174	228	227
Vaagen Bros 1	Vaagen Bros Lumber	Must Run	4	4	4	4	4	4	4	4	4	4	4	4
Valmy 1	Valmy 1	Valmy	127	127	127	127	127	127	107	86	86	86	127	127
Valmy 2	Valmy 2	Valmy	134	134	134	134	134	134	113	91	91	91	134	134
Vansycle Ridge	Vansycle	Must Run	6	5	9	11	12	16	4	5	4	4	3	5
Wah Chang	(unavailable)	PNW West NG 1												
Warm Spgs Forest Products	Warm Springs Forest	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
West Boise Waste 1	(lost)	Must Run												
West Point Treatment Plant 3	West Point	Must Run	1	1	1	1	1	1	1	1	1	1	1	1
Weyco Energy CTR 1	Weyerhaeuser Springf	Waste Burner	18	18	18	18	18	18	18	18	18	18	18	18
Whatcom MSW	Whatcom MSW	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
Willamette Industries (Albany) GT (	(unavailable)	PNW West NG 3												
Wood Plants 2	Evergreen Forest Pro	Must Run	5	5	5	5	5	5	5	5	5	5	5	5

Figure L-69: Existing Resources, Sorted by Name

Fuel	Heat Rate BTU/kWh	VOM 2004$/MWh	Unit Name	Alternative name/description	Aggr_Unit	Sep (MW)	Oct (MW)	Nov (MW)	Dec (MW)	Jan (MW)	Feb (MW)	Mar (MW)	Apr (MW)	May (MW)	Jun (MW)	Jul (MW)	Aug (MW)
##55	10836	1.83	Boardman 1	Boardman	Boardman 1	556	556	556	556	556	556	467	379	379	379	556	556
	9990	1.40	Jim Bridger 1	Jim Bridger 1	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 2	Jim Bridger 2	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 3	Jim Bridger 3	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 4	Jim Bridger 4	Bridger	173	173	173	173	173	173	145	118	118	118	173	173
##53	10240	1.83	Centralia 1	Centralia 1	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
##53	10240	1.83	Centralia 2	Centralia 2	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
	11170	1.30	Colstrip 1	Colstrip 1	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
	11170	1.30	Colstrip 2	Colstrip 2	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
	10650	1.83	Colstrip 3	Colstrip 3	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
	10650	1.83	Colstrip 4	Colstrip 4	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
	11010	1.83	Corrette	J.E. Corrette	Corrette	160	160	160	160	160	160	134	109	109	109	160	160
#112	5000	3.02	Encogen 1	Encogen 1-3	Encogen 1	151	154	158	160	160	159	138	117	115	114	149	148
###7	8000	2.15	Biomass-One 1	Biomass One	Must Run	23	23	23	23	23	23	23	23	23	23	23	23
###5	10064	2.15	Columbia Generating Station	Columbia Generating	Must Run	1170	1170	1170	1170	1170	1170	944	720	720	720	1170	1170
			Combine Hills I	Combine Hills I	Must Run	12	11	17	22	24	32	7	10	8	7	7	11
##30	0	1.40	Condon Wind Project Phase I	Condon 2001	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
##30	0	1.40	Condon Wind Project Phase II	Condon 2002	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
###7	8000	2.15	D R Johnson Lumber (Riddle, Coge	Cogen II	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
###7	5000	2.15	Everett Cogen 1	Everett Cogen	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
			Foote Creek	Foote Creek	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
###7	5000	2.15	Georgia Pacific (Camas)	Georgia-Pacific (Cam	Must Run	47	47	47	47	47	47	47	47	47	47	47	47
###7	5000	2.15	Georgia Pacific (Wauna)	Georgia-Pacific (Wau	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
###7	14380	2.15	Kettle Falls ST	Kettle Falls	Must Run	45	45	45	45	45	45	45	45	45	45	45	45
##30	0	1.40	Klondike	Klondike	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
###7	12380	2.15	Libby 1 Champion	(retired)	Must Run												
###7	15476	2.15	Libby 2 Champion	(retired)	Must Run												
			Mariah	Mariah	Must Run	0	0	0	0	0	0	0	0	0	0	0	0
##30	0	1.40	Nine Canyon	Nine Canyon	Must Run	14	12	20	25	27	36	9	11	10	8	8	12
##30	0	1.40	Nine Canyon	Nine Canyon Expansio	Must Run	4	4	6	8	9	12	3	4	3	3	3	4
##30	0	1.40	OR RPS/SBC Wind 03	OR RPS/SBC Wind 03	Must Run												
###7	17000	2.15	Pine Products	(out of the mix)	Must Run												
###7	8000	2.15	Potlatch Corp 1-4	Potlatch Corp. 1-4	Must Run	53	53	53	53	53	53	53	53	53	53	53	53
###7	5000	2.15	Prairie Wood Products (Cogen 1)	Prairie Wood Product	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
			Rock River	Rock River	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
###7	10000	2.15	Roosevelt Landfill	Hill	Must Run	9	9	9	9	9	9	9	9	9	9	9	9
###7	6000	2.15	SDS Lumber ST	(unavailable)	Must Run												
##30	0	1.40	Stateline	Stateline	Must Run	156	141	227	286	310	415	98	129	111	93	91	141
###7	14000	2.15	Steam Plant No 2 2	(retired)	Must Run												
###7	8000	2.15	Vaagen Bros 1	Vaagen Bros Lumber	Must Run	4	4	4	4	4	4	4	4	4	4	4	4
##30	0	1.40	Vansycle Ridge	Vansycle	Must Run	6	5	9	11	12	16	4	5	4	4	3	5
			Warm Spgs Forest Products	Warm Springs Forest	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
###7	8000	2.15	West Boise Waste 1	(lost)	Must Run												
###7	8000	2.15	West Point Treatment Plant 3	West Point	Must Run	1	1	1	1	1	1	1	1	1	1	1	1
###7	8000	2.15	Wood Plants 2	Evergreen Forest Pro	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
#114	6700	3.02	Hermiston Power Project	Hermiston Power	PNW East NG 1	581	600	617	629	630	621	536	454	443	435	564	566
#114	6800	3.02	Klamath Cogen Project	Klamath Cogeneration	PNW East NG 1	443	457	470	480	480	473	408	346	337	331	430	432
			Goldendale Energy Ce	Goldendale Energy Ce	PNW East NG 2	229	236	243	248	248	245	211	179	174	171	222	223
#114	7050	3.02	Hermiston Generating 1	Hermiston Gen 1	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
#114	7050	3.02	Hermiston Generating 2	Hermiston Gen 2	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
#114	7000	3.02	Rathdrum Power Project	Rathdrum Pwr Proj	PNW East NG 2	223	231	237	242	242	239	206	174	170	167	217	218
#114	7050	3.02	Coyote Springs 1	Coyote Springs 1	PNW East NG 3	208	215	221	226	226	223	192	163	159	156	202	203
#114	6950	3.02	Coyote Springs 2	Coyote Springs 2	PNW East NG 3	258	267	274	280	280	276	238	202	197	193	251	252
#120	8000	3.02	Glenns Ferry Cogeneration	Glenns Ferry Cogener	PNW East NG 3	8	9	9	9	9	9	8	7	7	7	8	8
#114	9500	8.62	Kettle Falls GT	Kettle Falls GT	PNW East NG 3	6	7	7	7	7	7	6	6	5	5	6	6
#114	8700	8.62	Klamath Expansion (GTs)	(no match)	PNW East NG 3												
#120	5000	3.45	Simplot Cogen 1	Simplot Pocatello	PNW East NG 3	8	8	8	8	8	8	8	8	8	8	8	8
#114	11600		Boulder Park	Boulder Park	PNW East NG 6	24	24	24	24	24	24	24	24	24	24	24	24
#114	10700		Finley	Finley	PNW East NG 6	25	26	26	27	27	27	24	22	21	21	24	24
#114	11500		Morrow Power	Morrow Power	PNW East NG 6	23	24	25	25	25	25	21	18	18	17	22	22
			Mountain View	Mountain View	PNW East NG 6	148	152	157	160	160	158	136	115	112	110	143	144
			North Side	North Side	PNW East NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#114	10750		Northeast	Northeast 1 & 2	PNW East NG 6	62	64	66	67	67	66	57	48	47	46	60	60
			Randolph Road 1- 20	Randolph Road 1- 20	PNW East NG 6	31	31	31	31	31	31	31	31	31	31	31	31
			Rathdrum 1 & 2	Rathdrum 1 & 2	PNW East NG 6	162	168	172	176	176	174	150	127	124	121	158	158
			Salmon 1 & 2	Salmon 1 & 2	PNW East NG 6	6	6	6	6	6	6	6	6	6	6	6	6
##84	13000		Boundary GT	(emergency)	PNW Oil												
##84	11600		Grays Harbor ICs	Hoquiam 1 - 5	PNW Oil	10	10	10	10	10	10	10	10	10	10	10	10
##84	11600		Okanogan Co PUD ICs Ph 2	Okanogan Co. PUD ICs	PNW Oil	25	25	25	25	25	25	25	25	25	25	25	25
#120	12100		Danskin	Danskin (Evander And	PNW So ID NG 2	83	86	88	90	90	89	77	65	63	62	81	81
#114	11500		Pasco	Pasco	PNW So ID NG 2	40	41	42	43	43	42	38	34	34	33	39	39
#120	8000	3.02	Rupert Cogeneration	Rupert Cogeneration	PNW So ID NG 2	8	9	9	9	9	9	8	7	7	7	8	8
			Boise Cascade Medfor	Boise Cascade Medfor	PNW West NG 1	8	8	8	8	8	8	8	8	8	8	8	8
#112	7000	3.02	Frederickson Power 1	Frederickson Power (	PNW West NG 1	259	265	271	275	275	273	237	202	198	195	255	255
#112	7000	3.02	River Road 1	River Road	PNW West NG 1	233	239	245	248	248	246	214	182	179	176	230	230
#112	5800	3.45	Wah Chang	(unavailable)	PNW West NG 1												
#112	7200	3.02	Big Hanaford	Big Hanaford	PNW West NG 3	233	239	245	248	248	246	214	182	179	176	230	230
#112	7000	3.02	Chehalis Generation Facility	Chehalis Generating	PNW West NG 3	489	501	513	519	520	515	448	381	375	369	483	482
			March Point 1&2	March Point	PNW West NG 3	132	135	138	140	140	139	121	103	101	99	130	130
#112	5500	8.62	SP Newsprint (Newberg)	SP Newsprint GT	PNW West NG 3	86	88	90	91	91	90	82	74	73	72	85	84
#112	8000	3.02	Sumas Energy 1	Sumas Energy	PNW West NG 3	116	119	121	123	123	122	106	90	89	87	114	114
#112	7700	3.02	Tenaska 1	Tenaska Washington I	PNW West NG 3	231	236	242	245	245	243	211	180	177	174	228	227
#112	5500	8.62	Willamette Industries (Albany) GT (	(unavailable)	PNW West NG 3												
#112	9200	3.02	Beaver 1-7	Beaver	PNW West NG 5	475	487	498	504	505	500	435	370	364	359	469	468
#112	11500		Beaver 8	Beaver 8	PNW West NG 6	23	23	24	24	24	24	22	20	19	19	22	22
			Crystal Mountain 1 &	Crystal Mountain 1 &	PNW West NG 6	3	3	3	3	3	3	3	3	3	3	3	3
			Eastsound 4 & 5	Eastsound 4 & 5	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#112	10600		Frederickson 1	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10600		Frederickson 2	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10711		Fredonia 1	Fredonia 1	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
#112	10711		Fredonia 2	Fredonia 2	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
#112	10300		Fredonia 3	Fredonia 3	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
#112	10300		Fredonia 4	Fredonia 4	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
			MEAD	MEAD	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#112	10600		Point Whitehorn 2	Point Whitehorn 2	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10600		Point Whitehorn 3	Point Whitehorn 3	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	11600		Springfield ICs Phase II	Springfield Ph II	PNW West NG 6	10	10	10	10	10	10	10	10	10	10	10	10
			Tacoma Landfill	Tacoma Landfill	PNW West NG 6	2	2	2	2	2	2	2	2	2	2	2	2
#112	11500		Bailey (Clatskanie GT)	Alden Bailey	PNW West NG 7	10	11	11	11	11	11	10	9	9	9	10	10
#112	13000		BP (Cherry Point) GTs	BP Cherry Point GTs	PNW West NG 7	69	70	72	73	73	72	66	59	59	58	68	68
#112	13000		Equilon GTs	Equilon GTs	PNW West NG 7	37	38	38	39	39	39	35	32	31	31	36	36
#112	13000		Georgia-Pacific (Bellingham) GTs	Georgia-Pacific (Bel	PNW West NG 7	9	10	10	10	10	10	9	8	8	8	9	9
			ICT PP&L/Utah&Wyo to	ICT PP&L/Utah&Wyo to	Valmy	184	160	168	154	187	187	178	171	189	265	296	253
	10030	1.83	Valmy 1	Valmy 1	Valmy	127	127	127	127	127	127	107	86	86	86	127	127
	10030	1.83	Valmy 2	Valmy 2	Valmy	134	134	134	134	134	134	113	91	91	91	134	134
###6	8000	2.15	Coffin Butte 1	Coffin Butte	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
###7	17000	2.15	Frontier Energy	(no match)	Waste Burner												
###6	8000	2.15	Marion Solid Waste 1	Covanta Marion	Waste Burner	9	9	9	9	9	9	9	9	9	9	9	9
###7	8000	2.15	Pocatello Waste 1	(lost)	Waste Burner												
			Short Mountain	Short Mountain	Waste Burner	3	3	3	3	3	3	3	3	3	3	3	3
###6	8000	2.15	Skagit Co Waste 1	(retired)	Waste Burner												
###6	8000	2.15	Spokane MSW 1	Spokane MSW	Waste Burner	21	21	21	21	21	21	21	21	21	21	21	21
###7	14000	2.15	Steam Plant No 2 1	(retired)	Waste Burner												
###6	12500	2.15	Weyco Energy CTR 1	Weyerhaeuser Springf	Waste Burner	18	18	18	18	18	18	18	18	18	18	18	18
			Whatcom MSW	Whatcom MSW	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2

Figure L-70: Existing Resources, Sorted by Aggregate Unit

Name	Heatrate	Fuel	FOR	FOR Stochastic	VOM	Sep-Nov	Dec-Feb	Mar-May	Jun-Aug
	kBTU/kWh	2004$/MWh			2004$/MWh	(MW)	(MW)	(MW)	(MW)
Boardman 1	10.836	$1.20/MMBTU	0.07	TRUE	1.83	556.0	556.0	408.3	497.0
Bridger	9.990	$0.89/MMBTU	0.07	TRUE	1.40	704.0	704.0	518.0	629.7
CCCT	7.270	PNW East NG_006	0.05	FALSE	3.11	610.0	610.0	610.0	610.0
Centralia	10.240	$1.82/MMBTU	0.07	TRUE	1.83	1340.0	1340.0	983.3	1197.3
Coal	9.550	$1.00/MMBTU	0.07	FALSE	1.94	400.0	400.0	400.0	400.0
Colstrip 1&2	11.170	$0.78/MMBTU	0.07	TRUE	1.30	614.0	614.0	450.7	548.7
Colstrip 3&4	10.650	$1.00/MMBTU	0.07	TRUE	1.83	1480.0	1480.0	1086.7	1322.7
Consv_LO	0.000	(none)	0.00	FALSE					
Consv_NLO	0.000	(none)	0.00	FALSE					
Contracts	0.000	(none)	0.00	FALSE					
Corrette	11.010	$1.00/MMBTU	0.07	FALSE	1.83	160.0	160.0	117.3	143.0
Encogen 1	5.005	Waste	0.07	FALSE	3.02	154.3	159.7	123.3	137.0
Hydro	0.000	(none)	0.00	FALSE					
Hydro Commercial	0.000	(none)	0.00	FALSE					
Must run	0.000	(none)	0.05	FALSE	0.00	1699.7	1956.3	1227.0	1444.7
PNW East NG 1	6.743	PNW East NG_006	0.05	TRUE	3.02	1056.0	1104.3	841.3	919.3
PNW East NG 2	7.032	PNW East NG_006	0.05	TRUE	3.02	915.7	958.0	729.3	796.7
PNW East NG 3	7.050	PNW East NG_006	0.07	FALSE	3.02	504.3	527.7	404.7	440.3
PNW East NG 6	10.603	PNW East NG_006	0.07	FALSE	3.02	495.3	515.3	408.7	438.7
PNW So ID NG 2	11.741	PNW So ID NG_004	0.00	FALSE	3.02	135.3	141.3	111.0	119.3
PNW West NG 1	6.968	PNW West NG A_006	0.07	FALSE	3.02	512.0	529.7	412.0	455.0
PNW West NG 3	7.337	PNW West NG A_006	0.05	TRUE	3.02	1318.0	1362.7	1062.0	1171.3
PNW West NG 5	9.200	PNW West NG A_006	0.05	TRUE	3.02	486.7	503.0	389.7	432.0
PNW West NG 6	10.637	PNW West NG A_006	0.05	TRUE	3.02	741.0	764.3	606.0	663.3
PNW West NG 7	12.879	PNW West NG A_006	0.07	FALSE	8.62	128.3	132.7	111.7	117.3
SCCT	9.810	PNW East NG_006	0.07	FALSE	8.65	100.0	100.0	100.0	100.0
Valmy	10.030	$1.00/MMBTU	0.07	FALSE	1.83	431.7	437.0	370.7	504.3
Waste Burner	4.000	Waste	0.10	TRUE		55.0	55.0	55.0	55.0
Wind	0.000	(none)	0.70	FALSE	1.06	100.0	100.0	100.0	100.0
Wind - MT	0.000	(none)	0.64	FALSE	1.06	100.0	100.0	100.0	100.0

Figure L-71: Surrogate Plant Characteristics

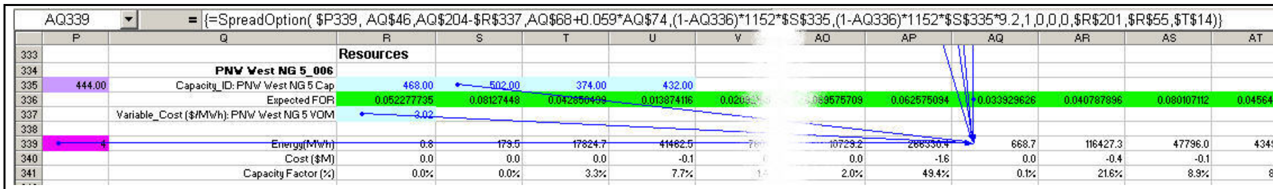


Figure L-72: Thermal Resource UDF References

System Benefit Charge Wind

Senate bill 1149, the state of Oregon's 1999 electric power restructuring legislation, established a "system benefit charge" which funds conservation and renewable development. Other states have looked at establishing similar reserves. Those responsible for renewables development have identified a preliminary system benefit charge (SBC) wind development schedule for the next 10 years. The regional model does not find that wind technology will be cost effective until the next decade, but SBC wind is included in the regional models baseline set of resources in the "must run" surrogate. SBC wind is one of very few future resources included in the baseline. It is included in part because it appears certain the region is proceeding with the development of this wind. It is included in part because the Council recognizes the importance of developing experience with this resource before it becomes a major resource for the region. The recommended plan relies heavily on commercially competitive wind generation after 2010.

The amount of SBC wind in the regional model's baseline appears in Figure L-73 [**11**]. Although the table extends only through 2014, these availabilities extend indefinitely in the regional model. Apart from the capacity duration forced outage rate assigned to the must run surrogate plant in the regional model, the model does not reflect the potentially complex forced outage nature of this resource.

Wind MWa	1st Mo			
Hydro Year	sep	dec	mar	jun
2004		17.5	20.3	19.7
2005	15.3	31.9	45.2	43.9
2006	34.0	53.9	71.0	68.9
2007	53.4	76.9	98.1	95.2
2008	73.8	101.8	128.0	124.1
2009	96.3	130.8	163.4	158.5
2010	122.9	167.6	209.7	203.4
2011	157.7	216.3	271.2	263.1
2012	204.0	284.7	359.3	348.5
2013	270.2	309.9	359.3	348.5
2014	270.2	309.9	359.3	348.5

Figure L-73: SBC Capability, by Hydro Year

Independent Power Producers

The PNUCC Northwest Regional Forecast identifies approximately 3200 average megawatts of IPP generation (3500 MW capacity) that is not under contract to Northwest load. Most of the generation is in the form of gas-fired combined cycle combustion turbines located in Washington and Oregon, much of that west of the Cascades. The 1300 MW Centralia coal-fired power plant located in western Washington is also part of that sum. The Council also surveyed the independent power producers of the region through the Northwest Independent Power Producers Coalition (NIPPC). NIPPC identify 3600 MW (capacity) in Oregon and Washington. Of that, approximately 1400 MW (capacity) is under contract through 2005, 950 MW is under contract through 2008, and 4300 MW is under contract beyond 2008. NIPPC noted, "... Virtually all IPP capacity is, as a result of transmission constraints and by design, committed exclusively to the Northwest."

The Council regards the IPP contribution to the wholesale electricity market significant, both in terms of power and of price stability. The Council chose to model the availability of this IPP generation in the market explicitly. Indeed, the Council considered the alternative of modeling ownership purchase or long-term contracts with IPP generators. They discarded this approach, however, because the region has no way of knowing what contract terms parties might eventually enter into through bilateral purchase or contract negotiation.

Although the energy from IPP generation contributes to the region's energy balance, and therefore affects price through the RRP algorithm, the value of these resources does not offset market purchases. Specifically, the energy is included in the system energy requirement calculation in cell {AQ676} of the sample workbook. When the surrogate plant is valued in the market, however, that portion of the surrogate's value associated with IPP generation does not contribute. A more concrete example of this follows.

Figure L-74 identifies regional IPP ownership [**12**]. The first column identifies the percentage of each plant under contract to meet regional load. The second column identifies to which surrogate plant each IPP unit is aggregated. To determine what fraction of the surrogate plant's capacity and value contribute to the region's portfolio, the seasonal availabilities are multiplied by the contract percentages and summed by surrogate plant. The original surrogate availabilities appear in Figure L-75. These availabilities contribute to the resource-load energy balance of the region. The seasonal availabilities meeting regional load appear in Figure L-76. These determine the amount of economic value the region gets. The fraction of each surrogate unit that contributes value to the region appears in the column on the right hand side of Figure L-76.

Contracted	Aggr_Unit	Unit Name	FoundinFazio	Location	Fall	Winter	Spring	Summer
0%	Centralia 2	Centralia 2	Centralia 2	PNW West	670	670	492	599
0%	Centralia 1	Centralia 1	Centralia 1	PNW West	670	670	492	599
0%	PNW East NG 1	Hermiston Power Project	Hermiston Pow	PNW East	599	627	478	522
21%	PNW East NG 1	Klamath Cogen Project	Klamath Coger		457	478	364	398
100%	PNW West NG 1	Frederickson Power 1	Frederickson F		265	274	212	235
0%	PNW East NG 2	Goldendale Energy Ce	Goldendale Energy Ce		236	247	188	205
100%	PNW East NG 2	Hermiston Generating 1	Hermiston Ger	PNW East	225	235	179	195
100%	PNW East NG 2	Hermiston Generating 2	Hermiston Ger	PNW East	225	235	179	195
0%	PNW East NG 2	Rathdrum Power Project	Rathdrum Pwr	PNW East	230	241	183	201
0%	PNW West NG 3	Chehalis Generation Fac	Chehalis Gene		501	518	401	445
0%	PNW West NG 3	Big Hanaford	Big Hanaford	PNW West	239	247	192	212
100%	PNW West NG 3	March Point 1	March Point	PNW West	135	140	108	120
100%	PNW West NG 3	Sumas Energy 1	Sumas Energy	PNW West	119	123	95	105
100%	PNW West NG 3	Tenaska 1	Tenaska Wash	PNW West	236	244	189	210
100%	PNW East NG 3	Coyote Springs 2	Coyote Springs	PNW East	266	279	212	232
0%	PNW East NG 3	Klamath Expansion (GTs	(no match)		0	0	0	0
0%	PNW East NG 6	Morrow Power	Morrow Power	PNW East	24	25	19	20

Figure L-74: IPP Capabilities

Orginal	Fall	Winter	Spring	Summer	Average
Centralia	1340.0	1340.0	983.3	1197.3	1215
PNW East NG 1	1056.0	1104.3	841.3	919.3	980
PNW West NG 1	512.0	529.7	412.0	455.0	477
PNW East NG 2	915.7	958.0	729.3	796.7	850
PNW West NG 3	1318.0	1362.7	1062.0	1171.3	1229
PNW East NG 6	741.0	764.3	606.0	663.3	694
	5883	6059	4634	5203	5445

Figure L-75: Surrogate Capabilities, including IPPs

Final	Fall	Winter	Spring	Summer	Average	Amt of Value to use
Centralia	0.0	0.0	0.0	0.0	0	0%
PNW East NG 1	96	100	76	84	89	9%
PNW West NG 1	512.0	529.7	412.0	455.0	477	100%
PNW East NG 2	449	470	358	391	417	49%
PNW West NG 3	578.0	597.3	469.0	514.7	540	44%
PNW East NG 6	717	739	587	643	672	97%
	2352	2437	1902	2087	2195	

Figure L-76: Surrogate Capabilities, without IPPs

To see a specific example of how these fractions are applied, consider the on-peak values for the surrogate plant "PNW West NG 3 006" which appear in row {429}. Recall from the discussion of valuation costing and of the thermal dispatch UDF that value is the negative cost appearing in this row. The formula in cell {CV429} discounts these values to the first period:

=0.434512325830654*8760/8064*NPV(0.00985340654896882,$R429:$CS429)*
(1+0.00985340654896882)

Comparing this formula to those described in section "Present Value Calculation," page L-79, we note that this formula has an additional leading coefficient of about 43.45%. This corresponds to the fraction identified on the far right hand side of Figure L-76.

Several of the Council members expressed interest in the impact that contracts for the export of firm energy outside the region might have on model results. A detailed discussion of the impacts appears in Appendix P[32] and in reference [**13**]. To summarize, the impact of such firm contracts would be nil. Of course, firm contract might reduce the pool of counterparties with whom regional utilities could deal. There would be no effect, however, on the market prices, upon which these LSEs are dependent for any unmet requirements.

New Resources

The new resources in the regional model

- CCCT
- SCCT
- coal plant
- IGCC
- demand response
- wind

are based on corresponding resources in the Council's Aurora model [**14**]. Figure L-77 and Figure L-78 summarize these. (The values in these figures are from the model runs for the final plan. Values in the example workbook and in examples appearing elsewhere in this appendix may differ.)

	Expected FOR	Stochastic FOR	Variable_Cost ($/MWh): VOM	Fuel Set (ID)	Heatrate (kBTU/kWh)
CCCT	0.05	FALSE	3.11	PNW East NG	7.270
SCCT	0.07	FALSE	8.65	PNW East NG	9.810
Coal Plant	0.07	FALSE	1.94	Coal_003	9.550
IGCC	0.10	FALSE	1.66	Coal_003	7.790
Demand Response	0.00	FALSE	0.00	(none)	(none)
Wind 1	0.00	FALSE	1.06+PTC+GT+Integration(Cap)	(none)	(none)
Wind 2	0.00	FALSE	1.06+PTC+GT+Integration(Cap)	(none)	(none)

Figure L-77: New Resource Parameters (1/2)

The section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65, describes the parameters in Figure L-78. Reference [**15**] documents the calculation of these values. In addition to the parameters discussed in that section, a column calculating the real levelized $2004 per kilowatt year has been added to the far right hand side of Figure L-78 for reference.

[32] See "Independent Power Producers," in the Appendix P chapter, "Sensitivity Studies."

	Criterion	Index	Planning_Periods	Optional_Construction_Periods	Committed_Construction_Periods	Planning_Costs (RL $M/MWPeriod^2)	Mothball_Costs (RL $M/MWPeriod^2)	Cancellation_Costs (RL $M/MWPeriod^2)	Construction_Costs (RL $M/MWPeriod^2)	CancelThreshold	Const Cost Escl (.01=1%/period)	Annual Escl	ResourceLife (periods	OptionLife (periods	PermitMarketAdds (T/F)	PlannedPlanning_Costs	RLL 2004$/kWyr
CCCT	R-L, then cost	0	0	4	4	0	0.00029	0.01168	0.00292	-99999	-0.086%	-0.34%	80	20	FALSE	0.00149	108.0
SCCT	R-L, then cost	1	0	0	4	0	0.00055	0.02185	0.00546	-99999	-0.100%	-0.40%	80	20	FALSE	0.00044	96.8
Coal Plant	R-L, then cost	2	0	5	9	0	0.00034	0.01355	0.00339	-99999	0.018%	0.07%	80	20	FALSE	0.00048	208.1
IGCC	R-L, then cost	2	0	8	8	0	0.00033	0.01310	0.00328	-99999	-0.116%	-0.46%	80	20	FALSE	0.00107	232.3
Demand Response	fixed	3	0	0	1	0	0.00005	0.00200	0.00050	-99999	0.000%	0.00%	80	80	FALSE	0.00002	2.3
Wind 1	R-L, then cost	4	0	2	2	0	0.00074	0.02970	0.00743	-99999	-0.430%	-1.71%	80	80	FALSE	0.00061	131.7
Wind 2	R-L, then cost	5	0	2	2	0	0.00166	0.06623	0.01656	-99999	-0.179%	-0.71%	80	80	FALSE	0.00135	293.7

Figure L-78: New Resource Parameters (2/2)

The CCCT, SCCT, Coal, IGCC, and demand response plants use the calculations described in sections "Thermal Generation" and "New Resources, Capital Costs, and Planning Flexibility" to determine costs[33]. While wind plants use the techniques described in the latter section for capital costs calculations, the variable cost calculation is different from that of the other new resources.

The variable cost for wind consists of four parts: variable operations and maintenance (VOM), green tag credit (GTC), production tax credit (PTC), and integration cost (IC). The VOM and IC increase cost; GTC and PTC decrease cost. The history of the PTC and GTC appear in Chapter 6 of the plan. The GTC and PTC are essentially aspects of the future, and Appendix P therefore covers their derivation. VOM is deterministic and IC is a function of wind deployment. This section therefore limits itself to how IC works and how the cost of wind incorporates these various cost components.

Windpower shaping costs range from $3 to $8 per megawatt hour, lower than expected several years ago. The model uses deterministic shaping costs: $5.02 per megawatt hour for the first 2,500 megawatts of wind capacity and $10.76 per megawatt hour thereafter (2004$).

In the example worksheet, the cells {AQ509} and {AQ510}, which compute the wind capacity and cost of capacity, use the same new capacity UDFs as the other resources, as just mentioned:

```
=lfPFCap(AP$314,AP$46,$P509)
```

[33] The model represents demand response as a combustion turbine with a fixed $150/MWh dispatch cost. When better information is available for describing the supply curve of regional demand response, the Council will enhance this representation. Also, while implementation uses the planning flexibility logic, the plan is fixed. Given the uncertainty surrounding the cost and availability of this resource, the Council elected to hold the plan for DR constant in all simulations.

=sfPFCost(AQ509,AP$46,$P509)

The energy (cell {AQ511}) is the capacity (MW) times the capacity factor times the number of on-peak hours in a standard quarter:

=AQ509*1152*0.3

The cost of wind (cell {AQ512}) in millions of 2004 dollars is

=AQ$511*(AQ$506-AQ$204)/1000000

Here the reader will recognize the now familiar valuation formula for costs, the energy times the value of the energy in the market. The on-peak price of electricity is in cell {AQ$204} and cell {AQ$506} contains the variable costs.

During the preparation of the final plan, the calculation of the variable costs change from what is in the sample workbook. This description will first explain the old logic in the sample worksheet. It will then explain how the new logic in the final plan works.

The sample workbook, the GTC and PTC went away completely with the advent of any carbon penalty. Moreover, the IC was $4.00/MWh for 2500 MW or less of wind and $8.00/MWh otherwise. The variable cost in cell {AQ$506} contains the formula

=IF(AQ74=0,AQ79+AQ505+AQ80+AQ81*(1+$R$78*AQ$46/80),AQ505+AQ80)

This formula is testing whether there is a tax for carbon. If so, the variable costs are the sum of the integration charge (cell {AQ505}) and the variable O&M in cell {AQ80}. The integration cost, in turn is given in cell

=IF(AP509+AP519>2500,2*$R$77,$R$77)

As we might expect, the integration cost formula merely doubles the $4.00/MWh in cell {$R$77} if the sum of the capacities for the wind plants exceeds 2500 MW.

If there is no carbon tax, then to these two terms the model adds the PTC (cell {AQ79}) and the GTC. The GTC has the formula

AQ81*(1+$R$78*AQ$46/80)

This simply changes the GTC linearly over time. Depending on the future, the GTC in the draft plan always started out at $6.66 (2004$) and increased or decreased linearly over time.

In the revised logic that the final plan employs, the situation is a bit more complicated. The GTC and PTC are relatively large, and several parties commented that it seemed unreasonable that these would disappear if even the smallest carbon tax occurred. The Council agreed. To make the behavior more realistic, the Council decided that PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains [34]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range. A complete description of the regional model's treatment of GTC and PTC appear in the Appendix P chapter, "Uncertainties."

[34] The conversion of carbon penalty ($/US short ton of CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh.

In the workbook, the variable cost formula is now

=AQ505+AQ82-AQ81-AQ83

The VOM in cell AQ82 of the new workbook is still fixed, and the integration cost in cell AQ505 is similar to the test described as above. The other two components, however, are more interactive with the carbon tax and the model treats them strictly as elements of the model future. Appendix P therefore describes those worksheet formulas.

Supply Curves

The portfolio model employs supply curves to represent conservation and price response hydro. This section describes data that the model uses, and it explains some of the choices and considerations behind these representations. During the Council's early modeling efforts, an unexpected relationship emerged between the shape of the supply curve and the value of conservation under uncertain market prices. This appendix describes those discoveries in section "Conservation Value Under Uncertainty," beginning on page L-129.

This section begins with a description of energy allocation for conservation across the on- and off-peak periods. The allocation pertains to both lost opportunity and discretionary conservation.

Energy Allocation

Figure L-79 illustrates the assumed conservation energy allocation by month [**16**]. Because these are percentages of annual energy, instead of power rates (MW), both the rate of usage and the number of hours in each subperiod influence the values. The regional model, which uses standard periods and power rates, requires the restatement of these percentages.

	High Load	Low Load
Jan	7.7%	1.9%
Feb	7.1%	1.7%
Mar	7.5%	1.5%
Apr	7.0%	1.6%
May	6.2%	1.3%
Jun	5.5%	2.0%
Jul	5.8%	1.5%
Aug	6.0%	1.2%
Sep	5.6%	1.3%
Oct	7.0%	2.0%
Nov	6.9%	1.8%
Dec	7.6%	2.1%
Jan	7.7%	1.9%
Feb	7.1%	1.7%

Figure L-79: Energy by Month

2005	High Load	Low Load	Total
Jan	416	328	744
Feb	384	288	672
Mar	432	312	744
Apr	416	304	720
May	416	328	744
Jun	416	304	720
Jul	416	328	744
Aug	432	312	744
Sep	416	304	720
Oct	416	328	744
Nov	416	304	720
Dec	432	312	744
			8760

	on-peak	off-peak	
Sp	1232	928	2160
Sum	1248	936	2184
Fall	1264	944	2208
Win	1264	944	2208
			8760

Figure L-80: Typical Hours Per Year and Hydro Quarter

Using the assumptions in Figure L-80, which represent a typical year, we obtain the average power by hydro quarter by subperiod in Figure L-81:

MW=MWh/hrs

There is significant difference in the weightings for on-and off peak power, but the seasonal variations in these factors is relatively small. To simplify calculations, the model uses the average of the seasonal values, which appear in Figure L-81. These averages are the constants to which the section "Conservation" (page L-44) and other sections refer.

	on-peak	off-peak
Sp	1.48	0.42
Sum	1.22	0.44
Fall	1.35	0.46
Win	1.55	0.53
average	1.402	0.465

Figure L-81: Relative Power Rates

Lost Opportunity Conservation

As explained in Chapter 3, lost opportunity conservation arises from new building construction and similar situations. While current codes and standards capture a significant amount of lost opportunity conservation, these effects are already captured in the "frozen efficiency" load forecast. That is, the frozen efficiency load forecast incorporates the effects of existing codes and standards on *future* growth in requirements. The lost opportunity conservation in the regional model's supply curves is therefore *new, incremental* conservation. Much of the potential for lost opportunity conservation comes from the advent of new technology.

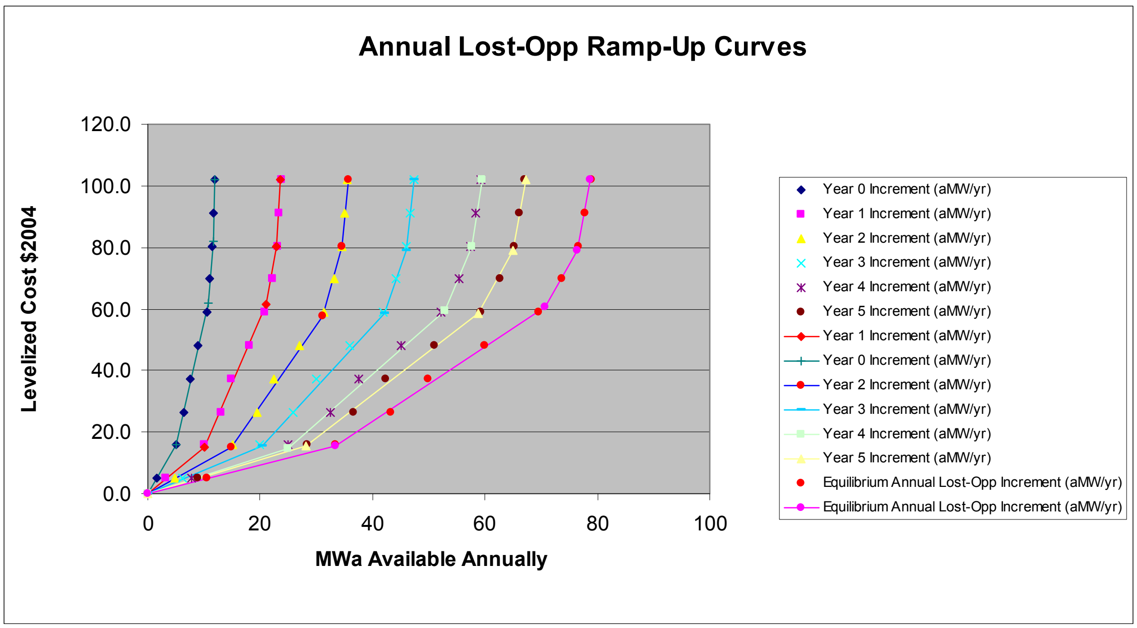


Figure L-82: Lost Opportunity Supply Curves

The regional model captures the development of new lost opportunity conservation technology through a sequence of supply curves that reflect increasing potential over time at each price point. This set of supply curves appears in Figure L-82, and the corresponding data appear in Figure L-83 [**17**]. At the bottom of Figure L-83, the reader will find the corresponding representation that the regional portfolio model uses. All supply curves reflect 5.5 mills per kilowatt-hour T&D credit and credit for any benefits unrelated to electric energy efficiency improvement.

In Figure L-83, six years pass before conservation achieves a mature level of potential. This mature level of potential is 85 percent of the theoretical potential. The Council recognizes that the even under the most optimistic conditions, the region will not be able to develop all conservation. Moreover, the rate of development is even more gradual in the regional model than this figure suggests. Instead of one year between supply curves, the regional model assumes two years, and no conservation commences before December of calendar year 2004. For lost opportunity, therefore, the first supply curve applies to the one year period after December 2004, the next supply curve applies to December 2005 up to December 2007, and the remaining supply curves apply every second year through December 2015, when potential reaches maturity.

Annual Energy (Q)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	5.06	10	14.9	20.3	25	28.1	33.5
Point 3	10.8	21.1	31.2	42.2	52.8	58.8	70.6
Point 4	11.6	22.9	34.6	45.9	57.7	65	76.5
Point 5	11.9	23.6	35.6	47.4	59.4	67.2	78.8

Quarterly Energy (Q)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	1.265	2.5	3.725	5.075	6.25	7.025	8.375
Point 3	2.7	5.275	7.8	10.55	13.2	14.7	17.65
Point 4	2.9	5.725	8.65	11.475	14.425	16.25	19.125
Point 5	2.975	5.9	8.9	11.85	14.85	16.8	19.7

Price (P)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	15.8	15	15	15.5	14.5	15.5	15.5
Point 3	61.9	61.5	57.6	58.5	59.5	58.5	60.5
Point 4	81.8	80.3	80.3	78.9	80.3	78.9	78.9
Point 5	102	102	102	102	102	102	102

0,0@+1.265,15.8@+2.7,61.9@+2.9,81.8@+2.975,102
0,0@+2.5,15@+5.275,61.5@+5.725,80.3@+5.9,102
0,0@+3.725,15@+7.8,57.6@+8.65,80.3@+8.9,102
0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102
0,0@+6.25,14.5@+13.2,59.5@+14.425,80.3@+14.85,102
0,0@+7.025,15.5@+14.7,58.5@+16.25,78.9@+16.8,102
0,0@+8.375,15.5@+17.65,60.5@+19.125,78.9@+19.7,102

Figure L-83: Lost Opportunity Supply Curve Values

As described in section "Supply Curves," page L-44, lost opportunity conservation depends on the rate at which construction is taking place, which is related to overall load growth. The supply curve logic for lost opportunity conservation accommodates this behavior. In the sample workbook, the cell {AQ377} contains the following formula

=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)

The last parameter in the UDF refers to cell {AP240}. Row 240 contains the ratio of on-peak load in column {AP} to an on-peak load benchmark level:

=AP183/AP195

If the period's on-peak load exceeds the period's benchmark on-peak load by 1%, the applicable supply curves quantity will increase 1% at each price level.

The section "Supply Curves" describes the remaining parameters in these formulas. The section “Decision Criteria,” page L-90, explains the price criterion (AP$233+$R$375) in this formula.

Discretionary Conservation

Discretionary conservation, also referred to as dispatchable or schedulable conservation, is energy efficiency that the region can pursue at any time. Some of these opportunities will disappear over time, so the supply curve represents a forecast of the balance of measures available in 2025. Figure L-84 illustrates a supply curve that the regional models uses for representing discretionary conservation. The values are in Figure L-85 [17]. This source of conservation also has a T&D credit of 5.5 mills per kilowatt-hour.

Discretionary conservation does not increase over time for a couple of reasons. First, the Council does not attempt to forecast technology improvements. The technology and standards are static. Second, the Council assumes that any structure built today with all cost-effective efficiencies will have no potential for additional improvement in 10 years. If conservation for the new facility becomes a lost opportunity, it remains a lost opportunity. It cannot become discretionary after some time has passed.

Several aspects of discretionary conservation economics became evident early in studies with the regional model. First, because there is so much discretionary conservation that is cost-effective at today's market prices that, without constraining the rate of development, the model would select unrealistic rates of conservation acquisition. In practice, program infrastructure, rate impacts, and budgets constrain development. To reflect this, the supply curve logic was modified to incorporate a rate limit. The Council considered several levels of ramp rate, and settled on a rate (30 MW) that appeared to significantly improve cost and risk but be realistic in light of some of the known

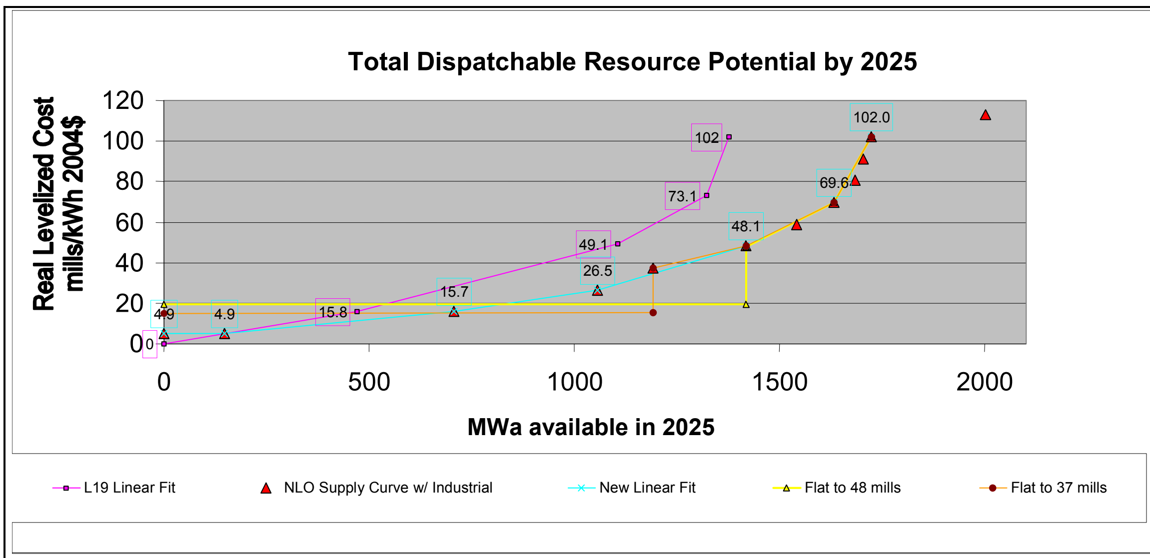


Figure L-84: Discretionary Conservation Supply Curve constraints. The selection of this discretionary conservation ramp rate is the subject of a sensitivity analysis in Appendix P.

The second aspect of discretionary conservation economics that became evident was that bundling of conservation programs prohibited strict implementation of the supply curve. When a utility decides to pursue discretionary conservation, they commit resources and crews to a commercial or industrial location. While at these locations, it makes economic sense to implement a host of programs, not just the ones below a given point on the supply curve. It is not realistic to expect that utilities will be able to "cherry pick" only those measures that are cost-effective and do so with 100 percent effectiveness.

Flat to 48 mills	
Energy (Q)	**Year 2025 Total Available**
Point 1	0
Point 6	1418
Point 6	1419
Point 8	1633
Point 11	1723
Price (P)	
Point 1	19.5
Point 6	19.6
Point 6	48.0
Point 8	69.6
Point 11	102.0

0,19.5@+
1418,19.6@+
1419,48@+
1633,69.6@+
1723,102

0,19.5@+1418,19.6@+1419,48@+1633,69.6@+1723,102

Figure L-85: Data for Discretionary Conservation Supply Curve

To model the situation, the model uses a modified discretionary conservation supply curve. Council staff decided to change the shape of the supply curve to increase the average cost of discretionary conservation available at the low end of the supply curve. Where to make these modifications is to an extent arbitrary. Council staff considered several factors including the regional portfolio model's apparent appetite for discretionary conservation costing less than 40 mills per kilowatt-hour, the historic performance of utility programs, and the mix of discretionary conservation measures available. The staff chose to represent discretionary conservation with a first block representing all the conservation under the curve up to 48 mils per kilowatt-hour. This is about 1490 average megawatts and average cost of 19.6 mils per kilowatt-hour in 2004 constant dollars. It includes 200 average megawatts of conservation above 40 mils per kilowatt-hour. [17]

The supply curve logic for discretionary conservation in cell {AQ377} contains the following formula

=sfSupplyCurve(AP235+$R$384,$P386,AP46,AP386)*1152*1.402

The section "Supply Curves" describes the parameters in this formulas. The section "Decision Criteria," page L-91, explains the price criterion (AP235+$R$384) in this formula.

Price Responsive Hydro

The model uses a reversible supply curve to represent price responsive hydro. Section "Supply Curves," page L-48, describes the considerations that went into selecting values to represent this resource.

Contracts

Contract data represents firm energy imports and exports to the region. The source of this data is the BPA 2004 White Book [18]. Energy values appear in Figure L-86 as extracted from the source. Note that this figure uses calendar years, not hydro years.

Using a calendar of NERC holidays, the energy values in Figure L-86 become power levels over each hydro quarter. This permits restatement in standard periods. Figure L-87 illustrates the resulting values, which the model then incorporates. Because the values provided by BPA extend only through 2014 and because of the regular pattern exhibited in the last several years, the model extends the pattern of energy values through the end of the study.

As explained in section "Contracts," page L-32, the model can counter-schedule these firm contracts for economic reasons. Consequently, the contracts have little effect on market prices. Counter-scheduling affects the amount of power available to the market, which stabilizes prices. The contracts, however, do affect portfolio economics and risk. Regional load still benefits from the protection that these contracts afford against economic exposure to the market.

This concludes the appendix description of resources that the regional model uses. The model represents existing regional resources in aggregate plants, but SBC wind and IPP modeling requires special attention. Contract data reflects the most recent BPA White Book, extended through the end of the study. Most new resources use the UDF described in the section "New Resources, Capital Costs, and Planning Flexibility" for capital costs; all new resources except wind use the UDF described in "Thermal Generation" for variable costs. Wind must account for integration cost and special renewables credits. New conservation energy has its own, special supply curve logic.

One aspect of the resources that this section did not discuss is how the model constructs plans. Plans must conform to certain constraints: A plant, once constructed, may not disappear the next year, for example, and there are constraints on the addition of wind generation. The next section describes how the Crystal Ball and OptQuest Excel add-ins use the regional model to prepare the feasibility space, including constructing plans subject to constraints and finding least-cost plans subject to risk constraints. It also describes some utilities that help the analyst make sense of the simulation results.

MWhs			Month											
On/Off Peak	Cal Yea	I/E	1	2	3	4	5	6	7	8	9	10	11	12
On-Peak	2004	Export								1009725	982675	877696	824291	874006
		Import								163798	127562	170293	313234	424215
	2005	Export	801258	733297	790424	773177	784213	876105	909973	910011	873102	742359	705020	736716
		Import	392401	318405	287876	234573	130284	172270	190170	187681	155162	179321	329674	412567
	2006	Export	727018	665963	737764	712355	739955	795224	811648	804054	772577	617872	585371	606787
		Import	382401	307691	269559	219490	102443	171521	181210	149319	132522	153725	301904	373910
	2007	Export	611999	552671	611035	592672	615517	672647	710778	728831	693228	609790	572397	594008
		Import	345772	262714	226411	178287	87527	143906	134992	140868	92166	139149	279464	363590
	2008	Export	554273	517882	548613	540204	548669	577665	591676	566925	552765	544691	505046	534237
		Import	265610	259835	231893	194563	106788	149176	156358	68746	56616	80397	157859	208871
	2009	Export	533241	481879	527510	522319	530517	566911	576003	615994	600009	593652	556458	587668
		Import	207370	179846	171864	133744	49577	84542	82144	68746	56616	80397	157859	208871
	2010	Export	582702	530029	584596	573560	583288	613019	623807	604813	589060	578493	551365	578666
		Import	201310	179846	176774	133744	49577	65323	63549	50151	56616	77930	123928	168103
	2011	Export	573659	521787	575314	564448	572062	607287	613611	602545	582472	571772	545234	572658
		Import	162110	142214	134438	92976	49577	65323	61792	51574	56616	77930	123928	168103
	2012	Export	567608	533510	569018	553813	567586	594468	600522	588566	564402	559651	530453	554066
		Import	162110	147835	134438	90327	50794	65323	61792	51574	54726	80397	117520	156565
	2013	Export	556503	502423	549805	543019	551864	574990	589465	573374	550241	553050	524466	548234
		Import	159981	136234	131096	92976	50794	63816	63549	51574	54726	80397	117520	156565
	2014	Export	550624	497030	543662	536926	545266	547101	560816					
		Import	159981	136234	131096	92976	50794	63816	63549					
Off-Peak	2004	Export								294739	277615	204704	200887	212999
		Import								151512	129214	157907	254667	322426
	2005	Export	206106	173346	185717	187526	187707	220818	278787	228051	227494	177214	175611	184580
		Import	315020	223304	199821	172771	114193	127641	180810	158877	151294	165046	267819	313242
	2006	Export	192800	162197	173580	184952	166932	190604	233049	225936	225078	113840	114234	127931
		Import	306420	215268	186592	175200	84375	127094	173105	131171	133182	144848	245665	306460
	2007	Export	121181	106807	113301	123682	103719	131737	176143	174600	181766	100408	106934	120228
		Import	254097	181529	155384	142399	72655	106883	133502	125022	107164	125005	227713	297585
	2008	Export	81735	71666	78202	78940	63894	81183	85311	83285	79150	69034	77862	80842
		Import	195503	176759	171776	138310	74153	103328	125513	60159	56590	68730	130767	142349
	2009	Export	80178	69203	76357	77201	64188	74782	83524	81268	77238	67130	78969	82189
		Import	133657	104994	108520	86326	31222	47578	66998	60159	56590	68730	130767	142349
	2010	Export	85423	70346	73597	78239	65095	75714	84594	82248	78101	72013	76203	83601
		Import	139718	104994	103609	86326	31222	28637	47277	40438	51694	61810	96586	112734
	2011	Export	86806	71546	74821	79328	66045	76693	90101	78848	78988	72996	77395	85051
		Import	108535	79055	75563	61165	26162	28637	49034	39016	51694	61810	96586	112734
	2012	Export	88228	73662	76080	84855	64784	77699	91245	79895	84318	63831	72235	83606
		Import	108535	81337	75563	63815	24945	28637	49034	39016	53583	59343	96586	117651
	2013	Export	79220	68301	74755	75553	59241	76751	81468	74743	78558	64894	73523	85174
		Import	104042	79055	78905	61165	24945	30144	47277	39016	53583	59343	96586	117651
	2014	Export	80757	69633	76115	76764	60299	77839	82705					
		Import	104042	79055	78905	61165	24945	30144	47277					

Figure L-86: Regional Contract Energy (MWh)

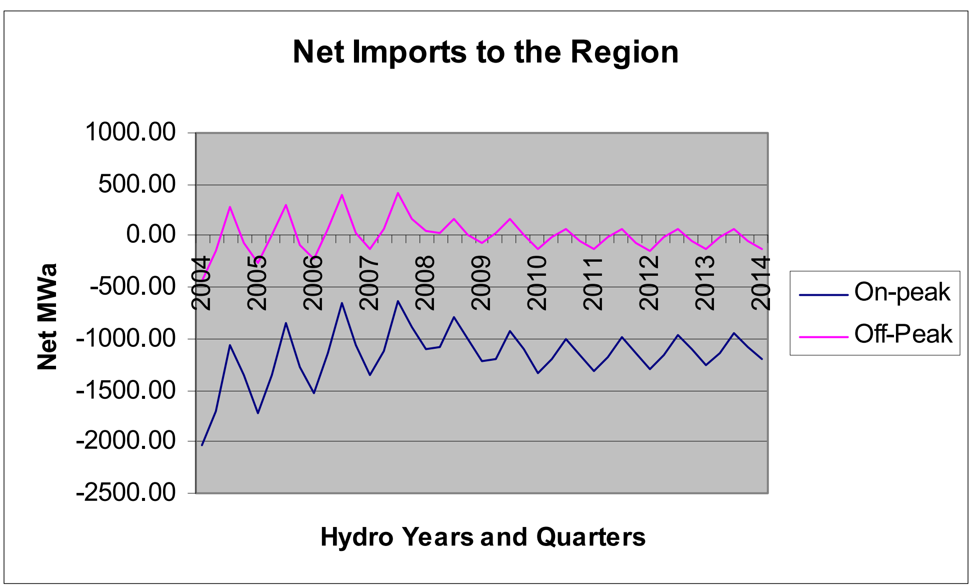


Figure L-87: Net Contract Imports MW

Using the Regional Model

This section describes how a user can run the regional model alone, or can use Excel add-ins to perform Monte Carlo simulation and plan optimization. The last portion of this section describes utilities the Council used to verify modeling and extract additional insights from the simulations.

Stand-Alone Calculation

When the workbook opens, the Excel calculation mode is set to Manual and special macros recalculate the worksheet in the order described in section "Logic Structure," at page L-9, and in section "RRP algorithm," page L-51. Because the workbook does not recalculate automatically, making changes to data in the workbook appears to have no effect.

To recalculate the worksheet, the user must execute the workbooks "Auto_Open" macro. By default, this macro is assigned the hotkey combination <CTRL>-I.

When the user presses <CTRL>-I, she can watch the calculations proceed from left to right across the worksheet. Recalculation requires about a second and a half. During recalculation, most of the values in the worksheet, and in particular the total system cost, are invalid. Their values may appear nonsensical. For example, prices may be negative.

Crystal Ball Simulations

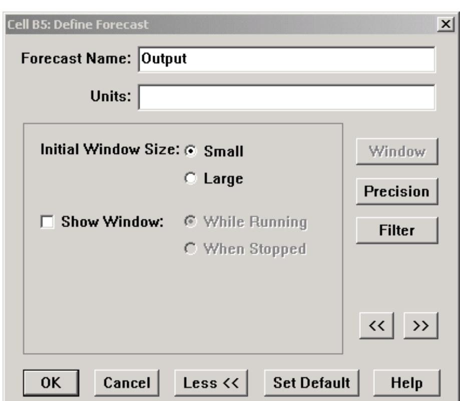


Figure L-88: Defining Forecasts

To perform Monte Carlo simulation or to prepare for creating a feasibility space, the user must specify Monte Carlo run preferences. The user should configure forecast cells to suppress forecast windows during the run, as in Figure L-88. Clicking on the Run Preferences button, illustrated in Figure L-89, the user has a sequence of choices to make.

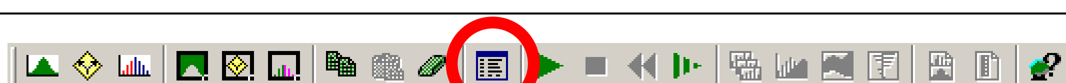


Figure L-89: Run Preferences

The first of these choices, illustrated in Figure L-90, determines the number of games or futures and how the application should handle calculation in each of those. Regional model studies used 750 games. This assured that there are 75 samples of the 10% worse outcomes. This number of samples yields a standard error that is about 12% of the tail's standard deviation. The 750 games provide a standard error of the mean that is about 4% of the distribution's standard deviation, or about $250 million net present value. Because of the size of the standard error of the mean, the Council always studied those plans that were nearly efficient. The Council examined all plans that were within $250 million cost and risk of the efficient frontier for evidence that a different resource strategy might be efficient.

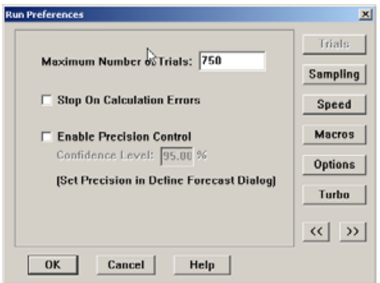


Figure L-90: Run Prefs, Trials

The second run preference is Sampling (Figure L-91). All studies used the same sequence of random numbers and the same initial seed value. Specifying the random number seed value is essential to reproducing and verifying simulations. Latin Hypercube is a statistical method that forces the sampling of less likely portions of a statistical distribution. All regional model simulations used the Latin Hypercube option.

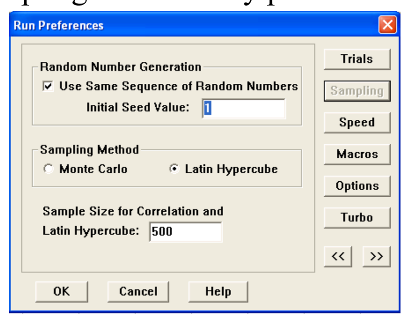


Figure L-91: Run Prefs, Sampling

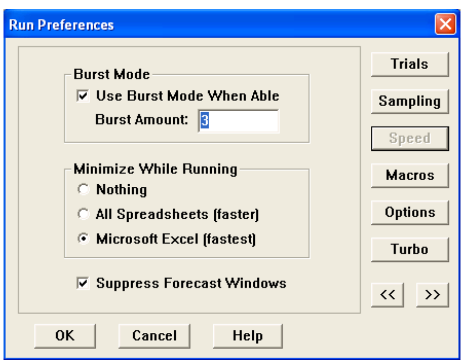


Figure L-92: Run Prefs, Speed

The third run preference, Speed, features an option called Burst Mode (Figure L-92). Burst Mode does different things depending on whether the user is running under Normal or Turbo simulation mode. Under Normal mode, this option suppresses screen updating for the number of games that the user specifies. Under Turbo mode, this controls the number of games each Worker receives in a packet. For the regional model, small packets containing only three futures appear to optimize performance.

The fourth run preference permits the user to specify macros that Crystal Ball will run during its simulation. The regional model employs two such macros, illustrated in Figure L-93. The macro names must be here whenever the user runs a Monte Carlo simulation or executes the regional model under Crystal Ball's single-step feature.[35] The regional model has a special macro that loads the names of the two subroutines into the correct fields in this dialog box. The user invokes this macro by pressing <CTRL>-M. Using the macro not only saves time but also reduces the likelihood of inadvertent errors. The

[35] Warning: The single-step feature does not reproduce the same games as when Monte Carlo simulation employs a user-specified seed value, even if the user specifies a seed value. The next section describes a utility to extract the values for assumption cells corresponding to a particular future.

subroutine names specified in this run preference dialog box must include the name of the regional portfolio model workbook. This name to typically changes from run to run.

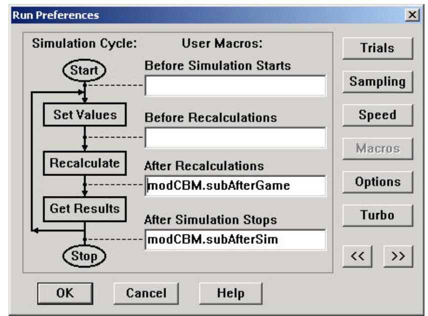


Figure L-93: Run Prefs, Macros

Executing the <CTRL>-M macro serves another purpose. For the macros in the regional model to perform correctly, there must not be any other Excel workbook present. Depending on the computer environment, Excel may load personal or hidden workbooks that are not evident to the user. This macro will locate any such workbooks and warn the user to close them.[36]

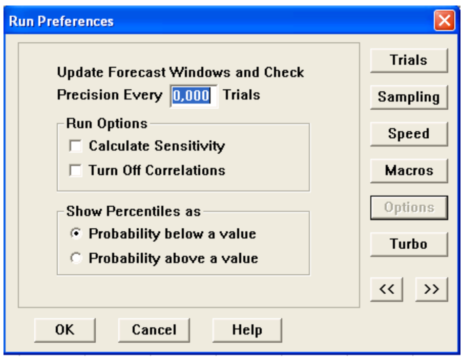


Figure L-94: Run Prefs, Options

Figure L-94 illustrates a fifth option, which should be set up as shown and thereafter disregarded. For reasons described in the next section, the regional model does not use precision or confidence testing.

The final option controls whether the Monte Carlo simulation will run in Normal (Figure L-96) or Turbo mode (Figure L-95). The user can run the regional model in either mode. For the Council's work, Turbo mode produced a tenfold decrease in run time for the creation of feasibility spaces. An important verification test, described below, is comparing the results of a plan run under Normal mode on a single machine and under Turbo model on multiple machines. The results for each game must be identical.

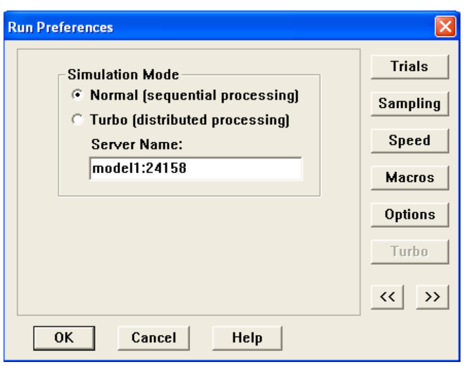


Figure L-96: Run Prefs, Turbo (Normal)

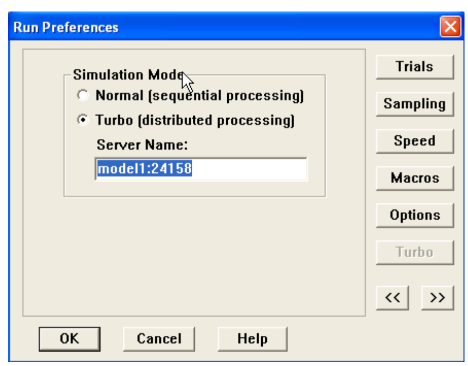


Figure L-95: Run Prefs, Turbo (Turbo)

[36] Closing the workbook may require entering the Visual Basic editing environment and issuing the Workbooks("***name***.xls").close command in the Immediate Window, where ***name*** is the offending workbook.

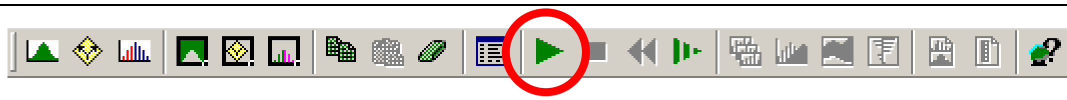


Figure L-97: Begin Simulation

With these preparations, the user is prepared to begin the Monte Carlo simulation using the start button in Figure L-97 or to prepare a stochastic optimization run as illustrated in Figure L-98. The next section describes considerations when preparing the optimization.

OptQuest Stochastic Optimization

When a user endeavors to create feasibility space using OptQuest, he can either open an existing configuration file or create one from scratch. If he chooses to create one from scratch, OptQuest will read the workbook and find all assumption, decision, and forecast cells. The user would then proceed through the following steps.

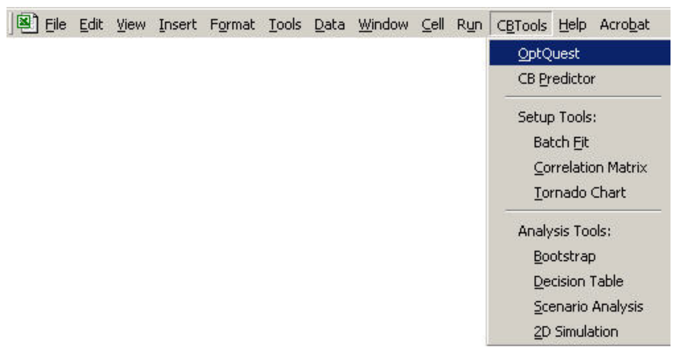
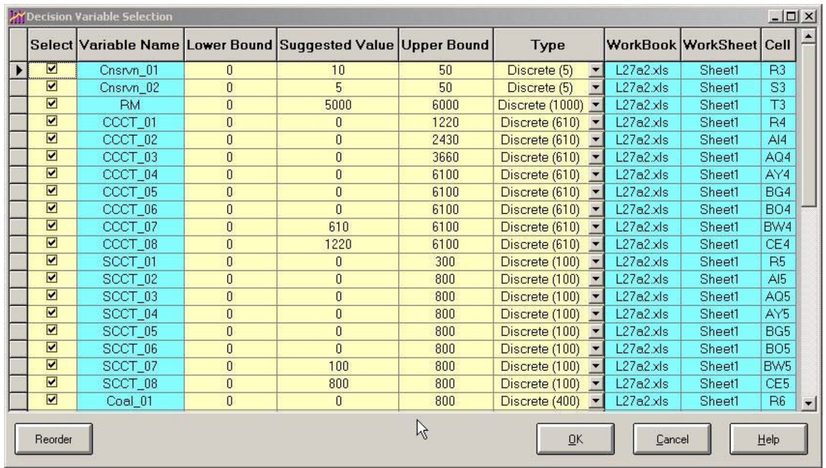


Figure L-98: Menu Bar

The OptQuest menu bar has four buttons that, proceeding from left to right in Figure L-99, open "Variable Selection," "Constraints," "Forecast Selection," and "Run Options" dialog boxes, respectively.

Figure L-99: OptQuest Menu Bar

Variable Selection, Figure L-100, is where the user specifies the value for decision cells. The optimizer will endeavor to perform its task by modifying the values of these cells. The column labeled "Type" specifies how the optimizer can vary the associated cell value. In this example, the optimizer can choose capacities for CCCT_01 in the fourth row between zero and 1220 MW in discrete steps of 610 MW. CCCT_01 is the decision cell that determines how much cumulative construction might be started by September of calendar year 2003. (See section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65.). CCCT_02 is the corresponding number of megawatts for December, 2007, and so forth. The user must determine step size, upper limit, and lower limit through trial and error. If an upper or lower limit is constraining the plans along the efficient frontier, this would be an indication that the values for the constraints should be adjusted. The user endeavors to keep the number of choices as small as possible, however, because the size of the search space grows explosively with the number of steps and decision cells available. [**19**]



Select	Variable Name	Lower Bound	Suggested Value	Upper Bound	Type	WorkBook	WorkSheet	Cell
☑	Cnsrvn_01	0	10	50	Discrete (5)	L27a2.xls	Sheet1	R3
☑	Cnsrvn_02	0	5	50	Discrete (5)	L27a2.xls	Sheet1	S3
☑	RM	0	5000	6000	Discrete (1000)	L27a2.xls	Sheet1	T3
☑	CCCT_01	0	0	1220	Discrete (610)	L27a2.xls	Sheet1	R4
☑	CCCT_02	0	0	2430	Discrete (610)	L27a2.xls	Sheet1	AI4
☑	CCCT_03	0	0	3660	Discrete (610)	L27a2.xls	Sheet1	AQ4
☑	CCCT_04	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	AY4
☑	CCCT_05	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	BG4
☑	CCCT_06	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	BO4
☑	CCCT_07	0	610	6100	Discrete (610)	L27a2.xls	Sheet1	BW4
☑	CCCT_08	0	1220	6100	Discrete (610)	L27a2.xls	Sheet1	CE4
☑	SCCT_01	0	0	300	Discrete (100)	L27a2.xls	Sheet1	R5
☑	SCCT_02	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AI5
☑	SCCT_03	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AQ5
☑	SCCT_04	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AY5
☑	SCCT_05	0	0	800	Discrete (100)	L27a2.xls	Sheet1	BG5
☑	SCCT_06	0	0	800	Discrete (100)	L27a2.xls	Sheet1	BO5
☑	SCCT_07	0	100	800	Discrete (100)	L27a2.xls	Sheet1	BW5
☑	SCCT_08	0	800	800	Discrete (100)	L27a2.xls	Sheet1	CE5
☑	Coal_01	0	0	800	Discrete (400)	L27a2.xls	Sheet1	R6

Figure L-100: Variable Selection

The values for decision cells illustrated in Figure L-100 are completely independent. The optimizer uses the equations in the Constraints dialog box, Figure L-101, to enforce any relationship among those values. The first seven equations in Figure L-101, for example, constrain the amount of CCCT capacity to be non-decreasing. The last seven equations in Figure L-101 specify that the model construct no more than 2000 MW of wind between decision cells. Two years separate each technology's decision cells after 2007 in the regional model.

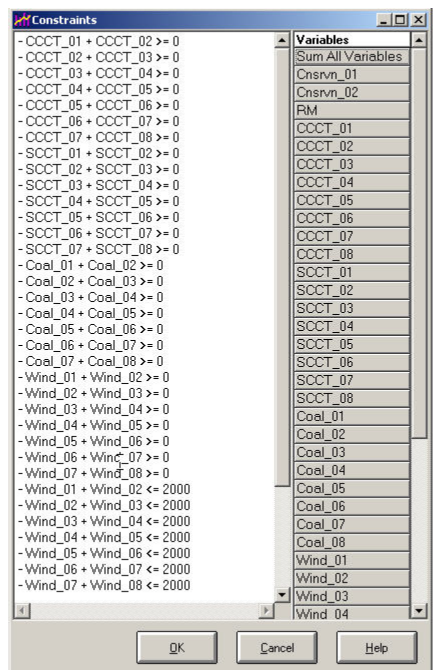
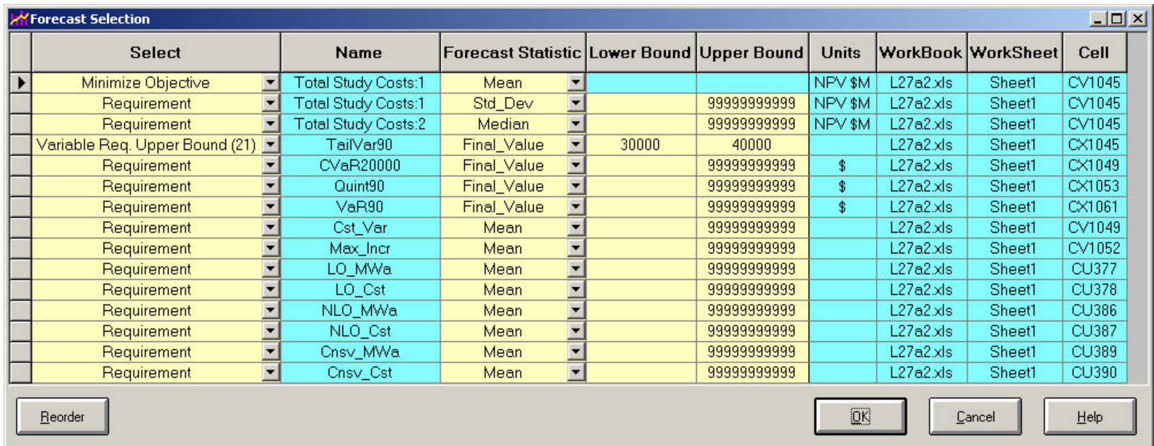


Figure L-101: Constrains

The "Forecast Selection" dialog window, illustrated in Figure L-102, is where the user specifies the objective function and risk constraint. The first row in this example specifies that our objective is to minimize total study cost. The fourth row specifies that a plan will be deemed feasible if it satisfies the upper bound on TailVaR$_{90}$. The optimization does not use the other rows. By specifying that other variables are requirements and placing an upper bound on these requirements guaranteed to be non-binding, the user fools the optimizer into keeping track of their values and reporting their values in the final optimization log.

Specifying that the TailVaR$_{90}$ risk measure is a variable-requirement upper bound permits the user to create the efficient frontier. Initially, this upper bound will start out at its lowest value, \$30 B in this example. (Bounds for TailVaR$_{90}$ in Figure L-102 are in millions of 2004 NPV dollars.) The optimizer will first attempt to find a plan that satisfies this upper bound. By choosing a sufficiently low upper bound, the user guarantees that the optimizer will seek the least-risk plan. After giving the optimizer sufficient opportunity to identify the least-risk plan, the user lifts the upper bound. In our example, the upper bound will have 21 even steps between \$30 B and \$40 B inclusive. (See the value in parenthesis under the first column.) After the upper bound has been



Forecast Selection

	Select	Name	Forecast Statistic	Lower Bound	Upper Bound	Units	WorkBook	WorkSheet	Cell
▶	Minimize Objective	Total Study Costs:1	Mean			NPV $M	L27a2.xls	Sheet1	CV1045
	Requirement	Total Study Costs:1	Std_Dev		99999999999	NPV $M	L27a2.xls	Sheet1	CV1045
	Requirement	Total Study Costs:2	Median		99999999999	NPV $M	L27a2.xls	Sheet1	CV1045
	Variable Req. Upper Bound (21)	TailVar90	Final_Value	30000	40000		L27a2.xls	Sheet1	CX1045
	Requirement	CVaR20000	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1049
	Requirement	Quint90	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1053
	Requirement	VaR90	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1061
	Requirement	Cst_Var	Mean		99999999999		L27a2.xls	Sheet1	CV1049
	Requirement	Max_Incr	Mean		99999999999		L27a2.xls	Sheet1	CV1052
	Requirement	LO_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU377
	Requirement	LO_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU378
	Requirement	NLO_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU386
	Requirement	NLO_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU387
	Requirement	Cnsv_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU389
	Requirement	Cnsv_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU390

Figure L-102: Forecast Selection and Requirements Specification

lifted a sufficient number of times, the optimizer will find at least one plan that satisfies the upper bound. At this point, the optimizer will endeavor to minimize the cost objective function. The optimizer will attempt to find the least cost plan subject to this risk constraint. After giving the optimizer sufficient opportunity to identify the least cost plan, the user then again lifts the upper bound on TailVaR_{90}. The optimizer will then endeavor to minimize cost subject to the new upper bound on TailVaR_{90}. The process continues until the optimizer has swept out the entire efficient frontier.

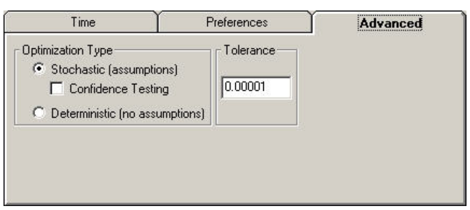


Figure L-103: Run Options (1/3)

Finally, the user specifies options for the run by clicking on the clock icon on the OptQuest menu bar (Figure L-99) to open the Options tab sheet. The first tab, labeled Advanced in Figure L-103, permits the user to specify whether optimization should be deterministic or stochastic. To create the feasibility space, the user selects Stochastic. It is imperative that the user leave the Confidence Testing option box unchecked. An undocumented problem running Crystal Ball Turbo under OptQuest produces random, meaningless results. The second to Options tab, Preferences, permits users to specify a descriptive string for output reports and the location of the optimization log file. An example of the log file appears below. The third Options tab, Time, permits the user to specify the amount of time for the optimization run. Using the Turbo mode, a feasibility space requires between 24 and 30 hours. Permitting two days for the optimization run should be ample therefore.

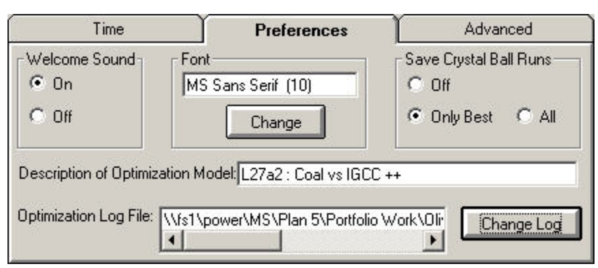


Figure L-104: Run Options (2/3)

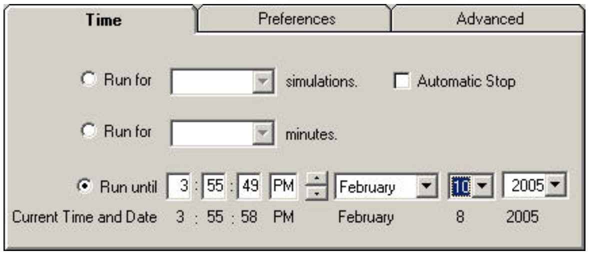


Figure L-105: Run Options (3/3)

The optimization is ready to run. The user may click on the run button in Figure L-106 to launch the optimization.

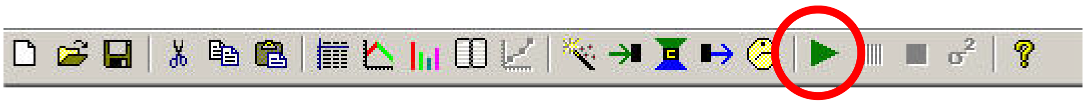


Figure L-106: LAUNCH!

Portfolio Model Reports And Utilities

In section "New Resources, Capital Costs, and Planning Flexibility," page L-74, the appendix describes a utility for extracting the planning status and cost for each cohort of a new resource. The Council has developed many other applications for extracting and evaluating regional model data. This section describes some of these utilities, including those that help the user perform the important tasks of verifying the computer simulations and "drilling down" through simulation results to the calculations performed by each cell for each plan, under each future.

This section describes utilities which
- create feasibility spaces and efficient frontiers
- extract data for each future and animate the "spinner" graphs, illustrating the behavior and performance of a plan under each future
- extract the assumption values for a particular future and populate a copy of the portfolio model with them for detailed examination
- run arbitrary sets of plans automatically and collect data
- paint prescribed cells with assumptions or forecasts
- compare two feasibility spaces to determine which, if any, plans are identical
- permit the user to compute the "stochastic adjustment" that results in distributions with a target mean, by period
- install menu bars to perform standard portfolio model or Olivia tasks, such as those listed above

Many of these utilities are included as special macros in the regional model. Some of them are macros in stand-alone workbooks. All of them are available to users from the Council upon request. They appear in this appendix because they demonstrate the ease with which and Excel-based model facilitates analysis. They also provide some insight into how the Council performed some of the tasks described elsewhere in this appendix.

Creating Feasibility Spaces and Efficient Frontiers

The previous section describes the means to constructing a feasibility space. A routine analysis is the comparison of two feasibility spaces. For example, one feasibility space may reflect a slightly modified set of assumptions, such as alternative probabilities for a CO_2 tax; the other may employ basecase assumptions. The comparison takes the form of an Excel graph such as the example in Figure L-107. The steps that the user would go through manually to create such a graph are:

- Convert the OptQuest output (see Figure L-108) to an Excel worksheet for analysis
- Sort the plans to reveal those that are 1) on the efficient frontier, 2) near the efficient frontier, and 3) do not belong to either of these categories (see Figure L-109)
- Re-label columns for easier comprehension. For example, the column of representing values for CCCT_02 might be relabeled to CCCT_1207 to reflect the fact that this decision cell controls construction beginning December 2007.

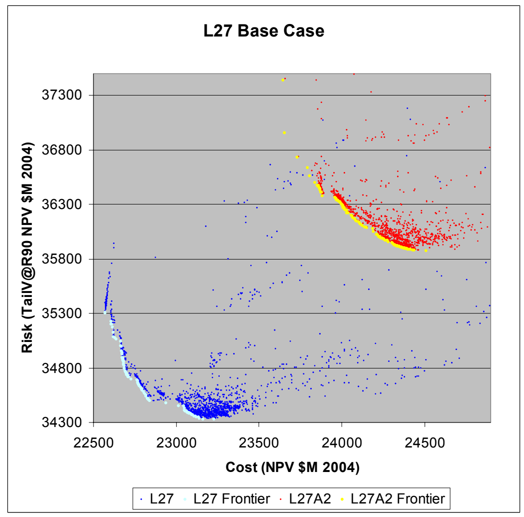


Figure L-107: Comparison of Feasibility Spaces

- Add the data points from the worksheet to a graph that already has the data points for the basecase. This includes identifying which points are on the efficient frontier and formatting those points with a distinct shape and color so that they are clearly distinguished.

The workbook "Analysis of Optimization Run.xls"[37] contains the macro sub_PROCESS, which performs these tasks automatically. To use the macro, the user merely identifies the file containing the OptQuest output and a string for labeling the analysis or sensitivity case.

It may be helpful to understand the typical structure of the worksheet containing sorted plans, illustrated in Figure L-109. An example of this report appears in worksheet "Base Case" of the workbook "Analysis of Optimization Run.xls." Figure L-109 is an abbreviated version, with certain columns and rows removed for clarity.

- Column A identifies the plan number, which is assigned sequentially as the simulations are performed
- Columns B through AR specify the value of decision cells. As described in previous sections, these specify the plan.

[37] This workbook is available from the Council's website or from the Council upon request.

- Columns AS through BG specify the values for forecast cells. These are the results of the simulation. Particularly significant are the mean net present value study cost in column AS and the TailVaR$_{90}$ risk in column AV.

```
Simulation: 1

Values of Variables:
Cnsrvn_01: 20
Cnsrvn_02: 10
RM: 5000
CCCT_01: 0
CCCT_02: 0
CCCT_03: 0
CCCT_04: 0
CCCT_05: 0
CCCT_06: 0
CCCT_07: 610
CCCT_08: 1220
SCCT_01: 0
SCCT_02: 0
SCCT_03: 0
SCCT_04: 0
SCCT_05: 0
SCCT_06: 0
SCCT_07: 200
SCCT_08: 200
Coal_01: 0
Coal_02: 0
Coal_03: 0
Coal_04: 0
Coal_05: 0
Coal_06: 0
Coal_07: 0
Coal_08: 0
Wind_01: 0
Wind_02: 0
Wind_03: 100
Wind_04: 600
Wind_05: 2500
Wind_06: 4500
Wind_07: 5000
Wind_08: 5000
IGCC_01: 0
IGCC_02: 0
IGCC_03: 0
IGCC_04: 425
IGCC_05: 425
IGCC_06: 425
IGCC_07: 425
IGCC_08: 425

Objective: Total Study Costs:1: Mean: 24421.4227133067
Feasible Requirement: Total Study Costs:1: Std_Dev: 5614.3871222492
Feasible Requirement: Total Study Costs:2: Median: 23223.7005012319
Feasible Requirement: TailVar90: Final_Value: 35924.8641878857
Feasible Requirement: CVaR20000: Final_Value: 26183.2357784132
Feasible Requirement: Quint90: Final_Value: 32370.2595941873
Feasible Requirement: VaR90: Final_Value: 7948.83688088056
Feasible Requirement: Cst_Var: Mean: 5.01001288051045
Feasible Requirement: Max_Incr: Mean: 13.503317703262
Feasible Requirement: LO_MWa: Mean: 1016.67790085181
Feasible Requirement: LO_Cst: Mean: 25.4497985131799
Feasible Requirement: NLO_MWa: Mean: 1561.91236255434
Feasible Requirement: NLO_Cst: Mean: 23.278176520789
Feasible Requirement: Cnsv_MWa: Mean: 2578.59026340615
Feasible Requirement: Cnsv_Cst: Mean: 24.1821505178384


Simulation: 2

Values of Variables:
Cnsrvn_01: 25
Cnsrvn_02: 25
RM: 3000
CCCT_01: 610
CCCT_02: 1220
CCCT_03: 1830
CCCT_04: 3050
CCCT_05: 3050
CCCT_06: 3050
CCCT_07: 3050
…. Etc….
```

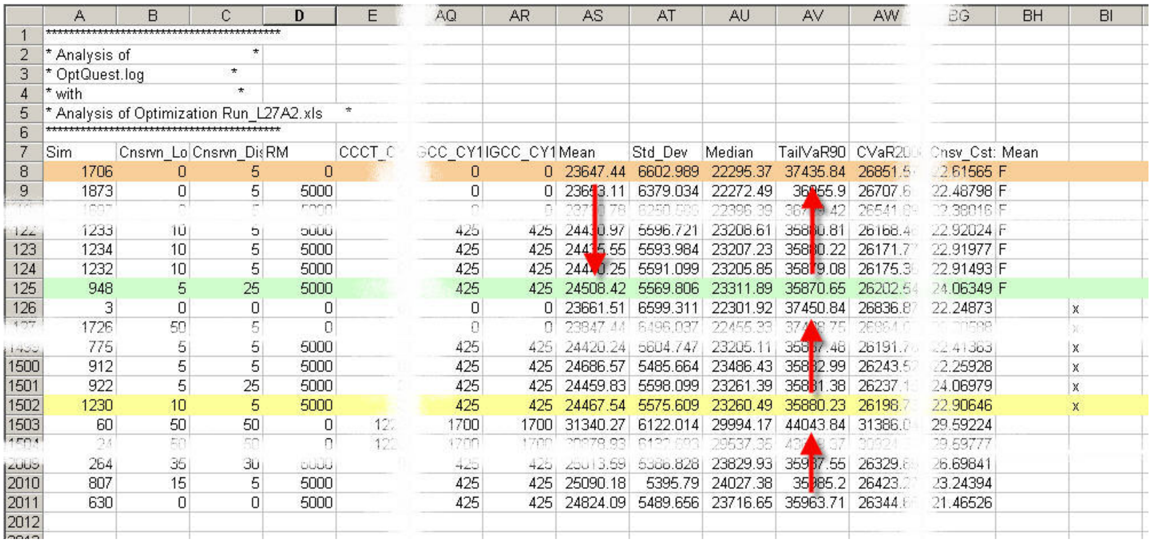
Figure L-108: OptQuest Log

- Column BH specifies plans on the efficient frontier. This report sorts the plans so that all of the plans on the efficient frontier appear together at the top of the report.
- Column BI specifies plans that are near the efficient frontier. These are plans within \$250 million cost and risk of the efficient frontier.

Plan A dominates Plan B if Plan A has lower cost *and* lower risk then Plan B. The plans on the efficient frontier of those plans that are not dominated by any other plan. Along the efficient frontier, sorting by risk automatically sorts by cost. We illustrated this sorting by the arrows in columns AS and AV of Figure L-109. For the remaining plans, there generally is no way to simultaneously sort cost and risk. The report sorts the near-efficient plans and the remaining plans, therefore, merely by risk.

Data Extraction And Spinner Graphs

A developer does not validate a strategic planning model that incorporates uncertainty the same way that he would most models. When a developer wants to validate the typical simulation model, he performs calibration of the model on a portion of historical data but withholds a portion of historical data for testing. Validation consists of checking the performance of the model against this test data. The situation is different for a long-term planning model. The future will differ from the past in ways that are predictable. For example, structural changes in the supply and demand of natural gas will affect future prices. New resources will similarly affect demand for natural gas, supply of electricity, and transmission power flows. Using data from the past would not be valid. Similarly, while some types of variation, like stream flows, may indicate future variation, they probably don't have any bearing on strategic uncertainty or risk. Strategic uncertainty deals with changes about which we have little current information, such as diminished stream flow due to climatic change, new regulation, or unforeseen changes in irrigation requirements.



	A	B	C	D	E	AQ	AR	AS	AT	AU	AV	AW	BG	BH	BI
1	**														
2	* Analysis of *														
3	* OptQuest.log *														
4	* with *														
5	* Analysis of Optimization Run_L27A2.xls *														
6	**														
7	Sim	Cnsrvn_Lo	Cnsrvn_Dis	RM	CCCT_C	GCC_CY1	IGCC_CY1	Mean	Std_Dev	Median	TailVaR90	CVaR20	Cnsv_Cst:	Mean	
8	1706	0	5	0		0	0	23647.44	6602.989	22295.37	37435.84	26851.5[illegible]	22.61565	F	
9	1873	0	5	5000		0	0	236[illegible]3.11	6379.034	22272.49	36[illegible]55.9	26707.6	22.48798	F	
[illegible]	1697	0	5	5000		0	0	237[illegible].78	6250.[illegible]	22396.39	36[illegible].42	26541.8[illegible]	22.38016	F	
122	1233	10	5	5000		425	425	244[illegible]0.97	5596.721	23208.61	358[illegible]0.81	26168.4[illegible]	22.92024	F	
123	1234	10	5	5000		425	425	244[illegible]5.55	5593.984	23207.23	358[illegible]0.22	26171.7[illegible]	22.91977	F	
124	1232	10	5	5000		425	425	244[illegible]0.25	5591.099	23205.85	358[illegible]9.08	26175.3[illegible]	22.91493	F	
125	948	5	25	5000		425	425	24508.42	5569.806	23311.89	35870.65	26202.5[illegible]	24.06349	F	
126	3	0	0	0		0	0	23661.51	6599.311	22301.92	37450.84	26836.8[illegible]	22.24873		x
127	1726	50	5	0		0	0	23847.44	6496.037	22455.33	37[illegible].75	2686[illegible]	[illegible]		x
[illegible]	775	5	5	5000		425	425	24420.24	5604.747	23205.11	358[illegible].46	26191.7[illegible]	22.41363		x
1500	912	5	5	5000		425	425	24686.57	5485.664	23486.43	358[illegible]2.99	26243.5[illegible]	22.25928		x
1501	922	5	25	5000		425	425	24459.83	5598.099	23261.39	358[illegible]1.38	26237.1[illegible]	24.06979		x
1502	1230	10	5	5000		425	425	24467.54	5575.609	23260.49	35880.23	26198.7[illegible]	22.90646		x
1503	60	50	50	0	12[illegible]	1700	1700	31340.27	6122.014	29994.17	44043.84	31386.0[illegible]	29.59224		
[illegible]	24	50	50	0	12[illegible]	1700	1700	30878.93	612[illegible]	29537.35	43[illegible].37	3092[illegible]	29.59777		
[illegible]	264	35	30	[illegible]		425	425	25013.59	5386.828	23829.93	359[illegible]7.55	26329.6[illegible]	26.69841		
2010	807	15	5	5000		425	425	25090.18	5395.79	24027.38	35[illegible]85.2	26423.[illegible]	23.24394		
2011	630	0	0	5000		425	425	24824.09	5489.656	23716.65	35963.71	26344.[illegible]	21.46526		
2012															

Figure L-109: Plans, Arranged By Cost and Risk

In lieu of traditional validation, therefore, the Council relies on decision makers' direct evaluation of futures. That is, witnessing individual futures, including all sources of uncertainty taken as a joint event, convinces decision makers and builds credibility. If decision makers find that the futures are realistic and the plans respond to the futures appropriately, they are apt to have confidence in the results.

The workbook L24DW02-f06-P.xls[37] contains the macro subRunPlans for running a simulation on a given plan and placing selected data from each of the 750 futures into specific worksheets. A collection of Excel graphs displays the data, including values for all sources of uncertainty in each period. A sample of these graphs appears as Figure L-7 through Figure L-11, starting on page L-12.

The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs."

The same workbook that creates the spinner graphs can also extract data for any cell in the portfolio model and for any set of plans, not just a single plan. The user can specify the plans to be subjected to the futures by pasting copies of the decision cells into the worksheet "Plans," as illustrated in Figure L-110. The macros in this workbook will

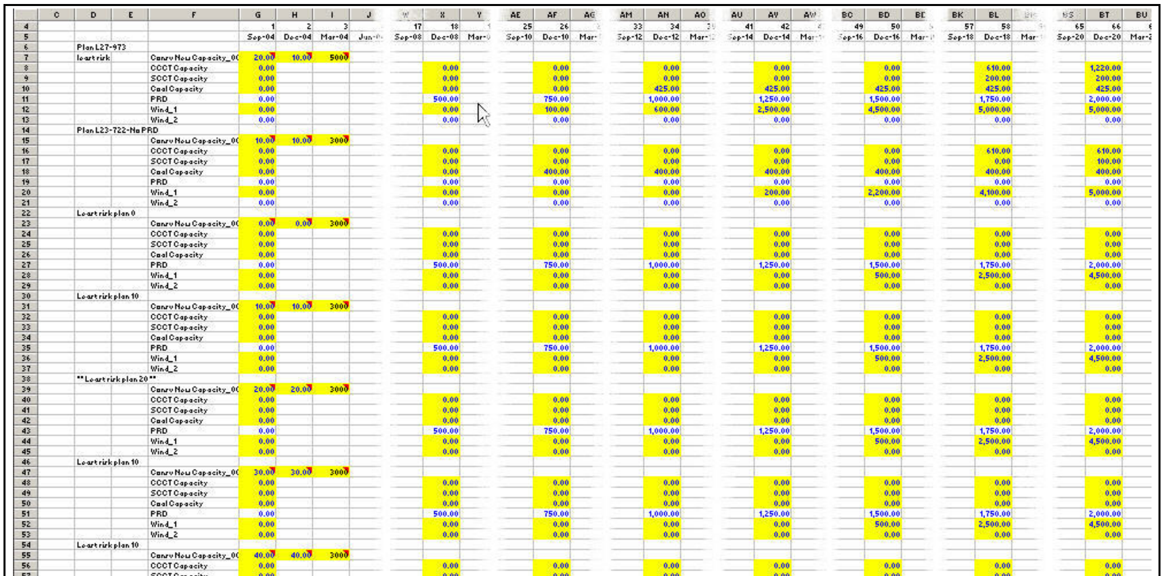


Figure L-110: Specified Plans Simulation Utility

perform a Monte Carlo simulation on each of these plans in turn and place the results in specified worksheets.

The data that the macro places into the selected worksheets comes from Crystal Ball forecast cells. To prepare a spinner graph, the user must prepare about 3200 forecast cells in the regional portfolio model worksheet. Converting a cell into a Crystal Ball forecast cell at a minimum requires the user to assign a unique name to the cell. The macro subAutoPaintForecasts in the workbook L24DW02-f06-P.xls does this work automatically. The macro reads instructions from the worksheet "Forecast Addresses", illustrated in Figure L-111. This worksheet identifies the rows and columns to be "painted with" forecast cells. The text in column B forms the names that the macro assigns to the forecast cells, together with the number of the column, and the address of the cell. Column H determines the names of the worksheets into which the macro places the resulting data. With a minor modification, this macro can also paint cells as Crystal Ball *assumption* cells.

	A	B	C	D	E	F	G	H	I
1									
2			long	long	long	long	long	string	
3	Description	Name	Start Row	Start Col	Width	Offset	Step	Root of New Worksheet Name	
4	natural gas price, 2004 $/MMBTU	NGP	68	18	80	0	1	NGP	
5	CO2 Tax, 2004 $/US short ton	CO2Tax	74	18	80	0	1	CO2Tax	
6	electricity price, independent term, 2004 $/MWh	EP_ind	104	18	80	0	1	EP_ind	
7	aluminum price, 2004 $/metric tonne	AL	174	18	80	0	1	AL	
8	electricity price, Western system, on-peak, 2004 $/MWh	EP_NP	207	18	80	0	1	EP_NP	
9	electricity price, Western system, off-peak, 2004 $/MWh	EP_FP	219	18	80	0	1	EP_FP	
10	annual reserve margin, MWa	RM	295	22	73	0	4	Other	
11	CCCT manifest capacity, MW	CCCT_cap	455	18	80	0	1	CCCT_cap	
12	SCCT manifest capacity, MW	SCCT_cap	469	18	80	0	1	SCCT_cap	
13	Coal manifest capacity, MW	Coal_cap	483	18	80	0	1	Coal_cap	
14	Wind manifest capacity, MW	Wind1_cap	509	18	80	0	1	Wind1_cap	
15	imports in addition to contracts, on-peak, MWh	Req_NP	676	18	80	0	1	Req_NP	
[illegible]	Unmet requirement[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	[illegible]	
[illegible]	[illegible]	Shortfall_Av	[illegible]	[illegible]	[illegible]	0	1	Shortfall_Av	
37	lost-op conservation, MWa	LO_MWa	1055	18	80	0	1	LO_MWa	
38	non-lost-op conservation, MWa	NLO_MWa	1056	18	80	0	1	NLO_MWa	
39	Total study cost (NPV $M 2004)	study_cost	1065	100	1	0	1	Other	
40	lost-op conservation EOS, MWa	LOEOS_MWa	377	99	1	0	1	CnsvEOS	
41	lost-op conservation EOS, 2004 $/MWh	LOEOS_Cost	378	99	1	0	1	CnsvEOS	
42	non-lost-op conservation EOS, MWa	NLOEOS_MWa	386	99	1	0	1	CnsvEOS	
43	non-lost-op conservation EOS, 2004 $/MWh	NLOEOS_Cost	387	99	1	0	1	CnsvEOS	
44	total (lost op + non-lost op) conservation EOS, MWa	CnsvEOS_MWa	389	99	1	0	1	CnsvEOS	
45	total (lost op + non-lost op) conservation EOS, 2004 $/MWh	CnsvEOS_Cost	390	99	1	0	1	CnsvEOS	
46									
47									

Figure L-111: Specified Cells To Make Assumptions or Forecasts

Calculations for a Particular Future

To verify the calculations in the regional model, the user must be able to drill down into the results to check calculations at the lowest level. Typically, when the user sees something that he or she does not understand, they will attempt to identify a plan in which that behavior is extreme. Using this plan, they look for a future in which the same behavior is evident. Depending on the issue, they may then need to trace the problem to a particular resource or period under that future. This final step requires that the user have access to the calculations taking place in every cell of the portfolio model worksheet for that plan and for that future.

As mentioned in the previous section (page L-110), single stepping with Crystal Ball does not reproduce the same sequence of futures that obtains from a simulation starting with a specific seed value for the random number generator. For this reason, it is necessary to run the simulation up to the future of interest. In simulation mode, however, the macros that the regional model uses to recalculate are not available to the user for experimentation and debugging. Therefore, the user must capture of the values of the assumption cells and put them in a copy of the regional model that the user can run independently, as described in section "Stand-Alone Calculation."

The user can run the Monte Carlo simulation up to the future of interest, and copy and paste the values of the regional model worksheet into a new worksheet. The workbook "L24DW02-f06-P.xls"[37] contains a macro, subCBAssumptionCopy, that transfers values from the cells in one worksheet to the corresponding assumption cells in a target worksheet. A dialog box interface prompts the user for the source and target worksheet names.

Finding the Intersection of Two Feasibility Spaces

Occasionally, an analyst may see something surprising and counterintuitive when he compares two feasibility spaces. For example, suppose the user were comparing two feasibility spaces, the first with a base case set of assumptions regarding resource availability, and the second with resources that were constrained relative to the base case. Perhaps the CCCT capacity expansion resource is constrained from developeding to the same quantity (megawatts) in later years as under the base case. We would expect that the efficient frontier for the base case would dominate that of the constrained case. That is, we would not expect a plan from the constrained case would outperform the plans from the base case. A natural question to ask would be, "has the model changed?"

This question may not be so easy to answer. Perhaps the computers or software versions are different. It may be difficult to reproduce a specific plan from the base case. Even if the results for a particular plan matched, we have little reassurance that results would have matched if we chose another plan.

The macro sub_Compare in the module mod_ComparisionOfPlans.bas[37] permits the user to locate and compare identical plans from two feasibility spaces. It compares two feasibility space plan listings, such as that illustrated in Figure L-109. Specifically, for any matching plan the macro reports the difference in mean distribution cost and $TailVaR_{90}$. If these are identical for all of the matching plans, the user has greater confidence that the difference he is seeing is real and not merely the result of the change in logic or platform.

This macro has served a particularly important role for the Council. Recall that the modeling process uses optimization to find least cost plans given risk constraints. The primary reason for using optimization is to avoid simulating and comparing a very large number of plans[38]. Optimizing nonlinear, stochastic processes is a thorny technical problem, and initial conditions and early results can lead the optimizer to suboptimal search strategies. By comparing two feasibility spaces, the user gets a better idea of when and why the optimizer began a particular search strategy. A plan like the one just described in our example may be the result of such alternative strategy. The efficient frontier produced for the base case may simply not be optimal.

This situation is a reminder that the Council's model is no substitute for judgment. The analyst must study the feasibility space to determine whether alternative strategies near the efficient frontier exist and are beneficial. She must also question whether she can improve the strategies on the efficient frontier.

It has been the experience of the Council that, where the base case efficient frontier has proven to be suboptimal, intervention made at best marginal improvement. Occasionally, one resource of a given fuel type can substitute for another of the same fuel type, and the optimizer may tend to report only one of these along the efficient frontier. This has had little impact on the overarching strategy along the efficient frontier, however. These observations have provided the Council with overall confidence in the optimizer's efficient frontier.

Stochastic Adjustment

Prices in the model derive from the Council's assumptions for long-term equilibrium prices[39]. For reasons discussed in Chapter 6, these equilibrium prices can be associated with the median price because there is equal probability of being above and below the median price. Some users may prefer, however, for the long-term equilibrium prices to match the price distribution's ***mean***. Because prices in the regional model use a lognormal distribution, however, the mean price is *higher* than the median price. (See Appendix P.)

To accommodate this situation, the model can apply a "stochastic adjustment" to the benchmark price. This adjustment, a number between zero and one, is chosen so that the distributions mean price matches the benchmark price. An example of a stochastic

[38] For the base case used in the final version (L28) of the plan, there are about to 5.1 x 10^{24} possibilities.
[39] Because the median and the mean both described the final distribution of prices after any adjustment, we refer to the starting place as the "benchmark price." The benchmark price is typically the long-term equilibrium price.

adjustment for on peak wholesale electricity market prices appears in the second row of Figure L-112.

	Series: Market Prices Independent Term_005				
Expected_Value_Set: Market Exp Price On-Peak 4x2	32.29	33.04	32.99	32.33	32.66
Stochastic_Adjust_Set: Stoch Adj On-Peak 4x2	0.87	0.73	0.78	0.76	0.85
Principal_Factor_Set: Reg Mkt Prc	-0.02037443	1.00			
Data_Series: Mkt Prin Fac Level	0.50				
	0.007267999	1.00			
Data_Series: Mkt Prin Fac Lin Growth	0.00	0.07			
Combined factors	-0.010187215	-0.009678455	-0.009678455	-0.009678455	-0.009678455
Jump_Set: Elec Mkt_002	8.770426174	0.072691876	8.899814829		
	16.07130502	0.100080134	11.46780741		
Combined Jumps	8.770426174	173.850772	0.072691876	173.850772	220.5905142
	0	0	0	0	0

Figure L-112: Stochastic Adjustment

Each period typically requires a separate stochastic adjustment. The regional model workbook macro subTarget automates this process. The user may specify several different prices, say wholesale electricity price, natural gas price, and oil price, and simultaneously find stochastic adjustments for each of these in every period.

Menu Bars

Menu bars are available for the portfolio model. These menu bars provide a simplified interface to many of the macros and utilities that this section describes. (See Figure L-113.) The menu bars are not in the regional model, because they interfere with distributed computation (see section ".")

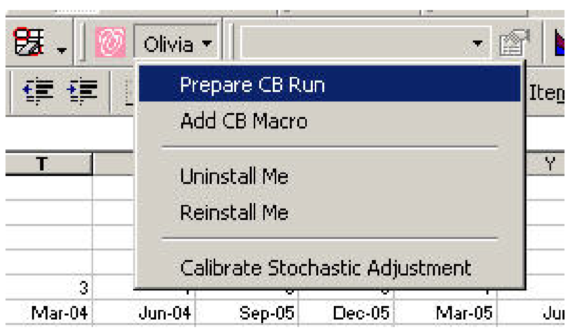


Figure L-113: Olivia Toolbar

Insights

This section summarizes some of the insights and discoveries the Council has made using the regional portfolio model. Many of these insights arose out of paradoxes, behaviors that contradicted our intuition about how the model should behave. For this reason, the section presents these insights as the answers to a series of questions.

General Paradoxes

"The model suggests that we should build the resources we don't expect to use. It calls for conservation that is not cost effective and power plants that are not 'used and useful.' How can we justify this?"

Building resources surplus to our requirements is analogous to buying insurance. We hope we never have to use it, but it would be foolish not to have the protection.

There are several differences between planning under uncertainty and planning with perfect foresight. Most strategic resource planning done today makes implicit use of the perfect foresight assumption. Whenever a plan assumes power plants recover their fully allocated costs or market price average around some long-term equilibrium level, planners are invoking perfect foresight.

Much of the planning today limits its treatment of uncertainty to what the Council would refer to as variation or variability. These are sources of uncertainty about which we have a great deal of information, such as hydro generation variability from year to year or the variation in loads due to weather. This kind of planning, however, does not embrace strategic uncertainty, the possibility that the underlying systems and markets themselves will change, perhaps dramatically and irreversibly. Embracing uncertainty means abandoning faith in averages and equilibrium. It means finding strategies that permit us to respond effectively and inexpensively to changing circumstances and protect us from the direst outcomes.

When we recognize that we need to protect our constituents from an uncertain future, insurance becomes useful. We hope that we will never have to use our insurance. We *hope* to lose money on the insurance, that we will forever pay a premium for our insurance and never have an opportunity to use it, *because if we ever do have to use our insurance, we will be worse off than we would have been otherwise*. The insurance merely reduces the magnitude of the damage; it does not eliminate it and it certainly should not reward us. (We would probably call such an expectation *speculation*, rather than risk mitigation.) Thus, some conservation and power plant capacity surplus to our anticipated need may not be used and useful, but it may be important protection.

Planning that does not embrace uncertainty not only fails to capture the insurance value of resources, but it in fact contributes to a riskier industry environment. Before the energy crisis, many utilities relied on the wholesale market instead of building their own resources. There are several reasons for this. The industry had surplus generating capacity and wholesale prices for electricity were low. Planners in the industry knew, however, that this situation would eventually correct itself. They relied on models, however, that computed long-term equilibrium prices for electricity. These planners elected to use a single price forecast for their analysis. Probably the single most meaningful price forecast is the long-term equilibrium price forecast, because it is the best estimate of where prices should return after any excursions, given a fixed set of assumptions. If one had to choose a single price forecast, this one would be the one to use. The problem with using a single price forecast, of course, is that it doesn't permit the planner to estimate the insurance value of resources. It does not tell the planner what kinds of risks he is incurring.

An insidious trap, however, lay in the fully allocated costs of some new resource setting the equilibrium price[40]. A CCCT is a typical candidate for new resource in the Pacific Northwest. If the planner is evaluating the utility-build decision using such a price forecast, it is unlikely that the utility build option will be cost effective. The new resource that sets the market price is the most cost effective in the region and is unlikely to be the unit that the utility is building. Even if the utility happens to be building the most cost-effective resource, however, there is no incentive to incur the risks associated with building a new resource if the planner believes the utility can purchase electricity from the market for a similar cost. Consequently, the utility does not build. Consequently, there is no gradual return of market prices to equilibrium. This produces a "boom and bust" cycle in electricity prices.

Cost-effectiveness levels change over time. Planning that ignores this will fail to capture the insurance value of resources, and in particular conservation. In the next section, this appendix documents how the shape of the supply curve for conservation and the changing cost-effectiveness level can make a policy of acquiring conservation in addition to that which appears cost effective today beneficial not only because of it reduces risk, but because the policy reduces *expected* cost.

"The regional model tells us that we need resource surplus to our needs for insurance purposes. Why don't the combustion turbines and coal plants my utility wants to build support this objective?"

The Regional Model tells us that having a little surplus is better than having a little deficit, but the principal strategic blunder would be to overbuild. Plans farther from the efficient frontier have higher levels of capacity.

Many utilities got themselves into difficulty during the energy crisis because of their exposure to the market. Twenty years ago, however, a crisis of equal if not greater proportion was visited on the region and much of the rest of the country when loads fell and ratepayers were exposed to fixed-cost risk. This is a source of risk that the regional model warns us may be a problem for the next decade. During the four years following the energy crisis, the region lost 2000 MWa of load and added 3000 MW of new power plants. Much of the load loss was from smelters that shut down. It is unlikely that most of these smelters will return to service. This 5000 MW is a significant portion of the 20,000 MW of regional load. The Council estimates that 3000 MW would probably have been sufficient to keep the region in balance during the energy crisis. Load growth in the region is approximately 300 MW per year, and new resources, such as the 500 MW Port Westward Project and portfolio standard wind, will continue to contribute to this surplus.

When it comes time to build for an energy reserve margin, the region has to be careful about the resources that it selects. A reserve margin criterion that only specifies how

[40] This is classical macroeconomics: equilibrium price equals long-term marginal cost.

much capacity to build surplus to requirements ignores economics and many important sources of risk. Confronted with a capacity reserve margin requirement, a utility will probably build a single-cycle combustion turbine (SCCT). On a dollar per kilowatt basis, this is the cheapest way to meet that requirement. A coal plant might be the cheapest way to meet an energy reserve margin requirement. Both of these fuels expose the utility to greater carbon emission penalty risk and fuel price risk, however.

"Why are IPPs included in the region? My utility has a resource deficit, but there isn't sufficient transmission capacity to wheel IPP power to our load center."

The focus of the regional model is economic efficiency and risk. Market prices across the western states do not deviate materially among themselves. Most of the time, they track each other closely. This means that a utility need not wheel power from a plant in order to reduce economic risk, because it can buy power in the market to meet its load center requirement and offset the cost of that wholesale spot power with the value of power used in a remote market. The economic effect is virtually identical to having a local power plant, selling into the market of the load center.

This is idea is not new; utilities have used this principle for many years. For example, Portland General Electric owns a portion of Colstrip Units 3 and 4 in Montana. While there are contracts to wheel this power to Portland, those contracts are counter-scheduled. When the Kaiser Mead and Columbia Falls aluminum smelter in eastern Washington shut down in response to federal buy-back offers in 2001, a remedial action scheme (RAS) shut down the Colstrip units to prevent instability on the Avista system. Power bottled up on the east side of the West-of-Hatway (WoH) transmission cut-plane. If the fiction of contract path transmission were true, and transmission lines were "electron pipes," there would be no reason for the Colstrip units to be taken down. The load situation in Portland certainly had not changed. The fact is, the Colstrip power is actually serving power loads and supporting the integrated power system east of the WoH cut-plane. Nevertheless, the Colstrip units remain a valuable economic hedge for PGE's customers against the more volatile market power purchased from the Mid-Columbia, and PGE accounts for the units as though the power meets Portland demand. Most utilities have similar arrangements.

"Surplus conservation appears to have a significant benefit to the region. The benefit, however, far exceeds the product of market price and surplus conservation capacity. Where is this extra value coming from?"

Modeling has revealed that early development of conservation can play an important role in moderating price volatility. Reducing price volatility reduces system cost. Conservation is uniquely suited to this task.

Early in regional model studies, the portfolio model used market value as the decision criterion for adding new resources. That is, when the model estimated that a resource would make money in the market based on the model's estimate of forward curves, it would proceed with construction of that resource. The exception to this situation, however, was conservation. Conservation has a slightly different decision criterion that caused continuous and early additions.

This situation effectively created a resource reserve margin. If a situation arose that created a price spike, this surplus of capacity mitigated the spikes. In fact, the value of conservation estimated by looking only at market price and the cost of the conservation would actually go down when the model added surplus conservation. Market prices lowered and conservation costs increased. Nevertheless, these plans performed better because the cost of serving load, a major cost component in the valuation equation, went down with lower market prices.

Conservation has certain advantages with respect to other resources as a source of energy reserve margin. One of these stems from the fact that, if conservation is to be developed into a significant resource, it needs to be developed continuously anyway. Whereas utilities can add power plant capacity on relatively short notice, conservation capacity must be added slowly over time, largely because the opportunities for securing conservation are constrained.

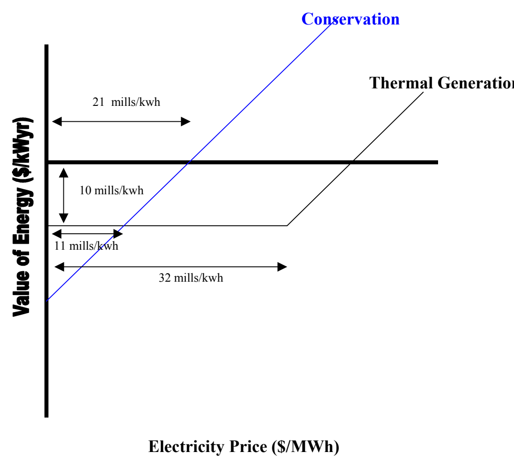


Figure L-114: Supply for Conservation vs Dispatchable

Another advantage of conservation is that it always contributes some value irrespective of market price. In Figure L-114, we assume a combined-cycle combustion turbine (CCCT) has a capital cost of 10 mills per kWh and a dispatch cost of 32 mills. It does not provide a positive net benefit until market prices exceed 42 mills. Assume that this CCCT is setting the market price, which would therefore be 42 mills. If this is the cost-effectiveness level of a supply curve for conservation that is linear between zero and 42 mills, the average cost of conservation would be 21 mills. Between 11 and 21 mills, both the turbine and the conservation would lose money, but the turbine would lose more money. Between 21 mills and 42 mills, the conservation is paying for itself, but the combustion turbine is not. Above 11 mills, conservation provides greater value than the CCCT. While some policymakers may be concerned that pursuing an aggressive program of conservation acquisition is risky when depressed market prices are likely in the future, this example suggests the opposite. Conservation would be the best solution unless market prices are extremely low, below 11 mills per kilowatt-hour. (And under that circumstance, lower purchase power costs for loads not met by conservation provide the utility a hedge against the extra cost.) This example, moreover, ignores the high-price risk mitigation value of conservation described in a previous paragraph.

In the past, system planners have regarded reserve margin primarily as a means to enhance system reliability. The economic and price effects of reserve margin have been largely ignored. The regional portfolio model identifies significant value in the price moderation effect of conservation. Others have seen this effect for renewables, as well. [**20**]

"The regional model appears to find larger energy reserve margins attractive the further out in time we plan. Reserve margins have traditionally been expressed as some percentage of loads or a fixed level of energy surplus to requirements. Why does the regional model's surplus requirements grow so much faster than load growth?"

One of the attributes of uncertainty is that it grows over time. As uncertainty grows, there must be a greater diversity of options and a greater availability (megawatts) of each option to cover contingencies. For example, assume we provide the regional model with only two candidates for new capacity: a coal plant and combustion turbine. There is greater uncertainty about loads and possible carbon penalty 20 years from today. It may also be likely that there will be high natural gas prices. Consequently, the best choice for the model is to plan for and site enough coal plant capacity and combustion turbine capacity to cover the entire load requirement. This may double the apparent amount of construction that the model is calling for. In fact, depending on the future, the owner would construct either one resource or the other, but probably not both.

A couple of related issue are the dependence of the regional model's plans – which specify options for construction – on uncertainty and the need to revise plans as that uncertainty resolves itself. The regional model specifies the risk-constrained, least-cost plans given today's view of uncertainty. Implicit in the plans is the assumption that decision makers must commit to siting and licensing today. For the most part, this is unrealistic. Before committing to plant siting and licensing for construction commencement ten years in the future, for example, there will be opportunities to review the plans to determine whether the siting and licensing costs are still warranted. Decision makers must use these opportunities to update information about assumptions and review plans before committing funds.

"The efficient frontier sweeps out a fairly small range of cost and risk. Given the magnitude of costs going forward, why is this trade-off curve so small?"

The primary reason the trade-off curve is small relative to the scale of costs in this study is that the regional model has no control over the choice of existing resources. While the model can choose resources going forward that reduce exposure to natural gas prices, for example, about 25% of the energy requirement will be met with natural gas in the future irrespective of what the regional model chooses.

We see in many of the sensitivity studies presented in Appendix P that the impact of uncertainties dwarfs the effect of resource choice. The efficient frontier, which may represent a trade-off of \$500 million to \$1 billion, moves between \$6 and \$10 billion if expected gas prices double. CO_2 emission penalties can have even larger impacts. Both of these affect the existing system, over which the model has no control. Perhaps it is useful to remember the relative scale of that which is controllable, compared to that which is out of our hands.

"Market prices in the regional model do not behave as we would expect. For example, you are not building any resources in the future and loads are increasing. Nevertheless, electricity prices stay low. Moreover, if you increase import-export capability, market price volatility increases instead of decreasing. Access to greater imports increases reliability, doesn't it? How do you explain this?"

A model that explicitly incorporates uncertainty behaves in ways that are counterintuitive to those who have used in deterministic models. This behavior is due to two terms: locality and modeling degrees of freedom.

Locality means the model is capturing behavior of local resources and loads, based to a large part on local prices for natural gas and other local parameters. This representation, however, ignores much of the world and many, perhaps most, sources of uncertainty. While local electricity prices depend on local loads, local hydro generation, and local natural gas prices, these factors describe perhaps half of the variation in electricity prices. As we saw during the energy crisis, factors completely outside of the region can determine our local electricity prices. Looking forward, it is easy to see that a California policy encouraging the building of surplus resources probably will affect local prices for electricity. Technology enhancements that may reduce loads and electricity prices are not represented explicitly anywhere in the regional model. For these reasons, a significant contribution to the price of electricity is an independent stochastic variable, intended to represent these factors in aggregate. This large source of uncertainty is unrelated to explicitly modeled, local factors. How can market prices remain low when loads are increasing in no resources are being built? Through non-local factors, such as purchases of inexpensive electricity, supplied by breakthrough solar photovoltaic technology or from conventional resources that are now surplus to depressed copper mine electricity requirements outside the region, for example.

Because of the first law of thermodynamics, energy supply and load must balance. Electricity price, which has the special independent term described in the previous paragraph, determines generation and must have an additive inverse among other parameters in the model. This is a mathematical degrees-of-freedom requirement. (See discussion of the section “RRP algorithm” beginning on page L-51.) In the case of the regional model, import-export capability is the dual to electricity market price. That is, given a market price that includes the independent term, import-export energy together with regional generation must match regional load requirements exactly. If electricity market price uncertainty is large, import-export capability must be large to accommodate the balance; small import-export capability accommodates only a small amount of electric price uncertainty. Having no import-export capability implies that there is only one price that balances system load requirements, that is, there can be no uncertainty about electricity prices. This explains the behavior to which the opening question refers.

To understand intuitively what is taking place in the regional model, think of the regional market as extending to the out-of-region market, via the transmission system. Much of the uncertainty comes from the out-of-region market. If the import-export capability is small, the exposure to this larger market is small. The converse is also true.

The duality between wholesale market prices and import-export levels is in a sense arbitrary. A modeler could choose variables other than import-export capability to maintain energy balance. For example, adjusting regional loads would establish balance. Alternatively, regional resources could have been manipulated through forced outage rates to achieve the same end. Using these mechanisms would have introduced the same questions about cause-and-effect, however.

Whenever we attempt to model closed systems, like transmission constrained power systems, there are conservation laws that constrain the degrees of freedom. Prices, for example, are a direct function of supply and demand in modeling. Similarly, variation of one parameter, say price, correlates perfectly with load or the sum of generation. This representation permits no freedom of any parameter from any other; all variables are dependent variables. Constraining parameters transfer variation on to other variables. If all but one variable is constrained, they all are. In our case, market price variation is dual to imports and exports.

From these observations, we conclude uncertainty models should aspire to feasible scenarios, not complete explanations. In engineering models, such as circuit diagrams, the initial conditions and the system characteristics determine the future state of the system. An analyst can explain all behavior in terms of the model and inputs. Within an uncertainty analysis, where much of the input is, by definition, unknown, the analyst does not have an explicit, detailed story that explains why stochastic variables assume the values that they do. He nevertheless must assure the behavior does not violate the laws of physics. The behavior of the stochastic variables should not conflict with what the decision maker believes is possible, although the decision maker may find the behavior highly unlikely. The decision maker must recognize the scope of possible influences.

Conservation Value Under Uncertainty

As the previous section explains, conservation cost and risk mitigation originates from several sources, including conservation's contribution at low prices and the effect that early conservation development has on reserve margin and price volatility suppression. One of the discoveries that the Council made during studies under uncertainty was that the shape of the conservation energy supply curve could justify policies that would seem foolish if decision makers were to ignore uncertainty.

The following argument is somewhat long, but the basic idea is simple. Under certain circumstances, if the supply curve is nonlinear, the policy of acquiring more conservation than a cost-effectiveness standard would deem prudent can lower cost. Consider a simple world where there are only two market prices, p_1 and p_2, and these occur with equal frequency. (See Figure L-115) In this case, of course, the average price is between the two. Assume that these two prices fall on different segments of the supply curve for lost opportunity conservation, as shown.

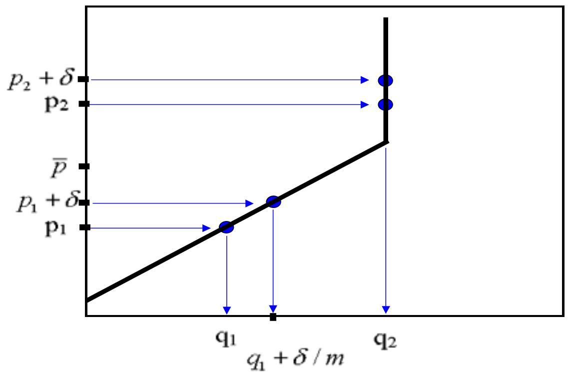


Figure L-116: Supply Curve with Premiums

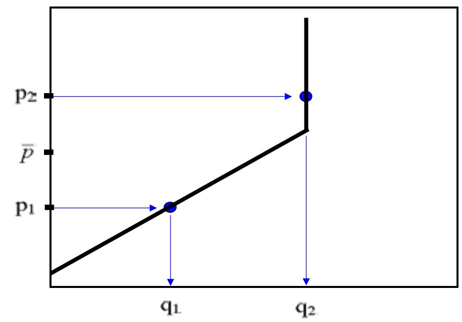


Figure L-115: Nonlinear Curve, Market Prices

Consider now the policy where we acquire conservation up to higher prices, ***p₁+δ*** and ***p₂+δ***. We obviously acquire more conservation than we would have without the premium when the market is at the lower price, p_1. Because the supply curve is vertical at p_2, however, the policy does not result in any additional acquisition at the price p_2. The policy results in acquiring more conservation at cost that is below average. Figure L-117 shows the value of the policy as the shaded area. This figure uses the same cost and value assumptions, such as "no producers' surplus," that the appendix detailed in section "Supply Curves."

Several aspects of this example are unsatisfying. For example, conservation acquisitions must be borne over the life of the measure. This example does not address that. The remaining portion of this section, therefore, provides a more detailed example.

Before proceeding, note that this example is intended to illustrate how the policy we have just described *can* result in lower cost. This is not to suggest that it *must* result in lower cost. Whether this policy reduces cost depends in a sensitive fashion on assumptions about the shape of the supply curve, the time value of money, and other things that this example intentionally glosses over for the purpose of keeping the example a simple as possible.

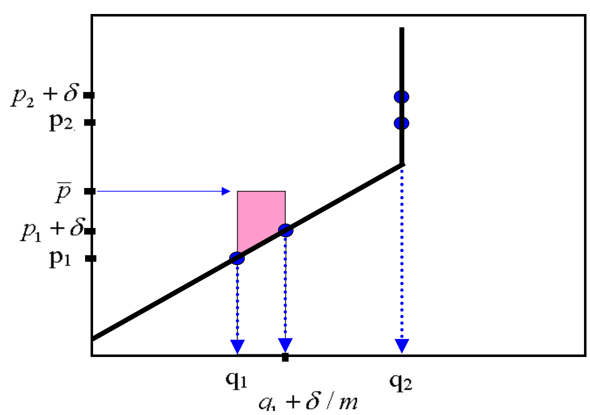


Figure L-117: Value of the Policy

In this example, we repeatedly referred to market price as a cost-effectiveness standard. This is a shorthand way of talking about whatever kind of cost-effectiveness standard would make sense to a decision maker. The Council has traditionally used a long-term equilibrium electricity price forecast produced by a spreadsheet model or by the Aurora model. That price effectively turns out to be the fully allocated cost of the least-expensive resource over the long term, typically taken to be a CCCT. This cost-effectiveness standard changes slowly, but its variation can still be quite large. In the late 1990s, this value would have been about $20 per megawatt hour. During the energy crisis, it could have been hundreds of dollars per megawatt hour in the short term, but probably would have remained about $20 per megawatt hour in the long-term. Today, with expectations for natural gas prices running about twice as high as they have historically, this value would be $35-$40 per megawatt hour. Irrespective of the nature of the cost-effectiveness standard, it is critical to recognize that there is variation and uncertainty in the cost-effectiveness standard over time. If that is recognized, the following example pertains.

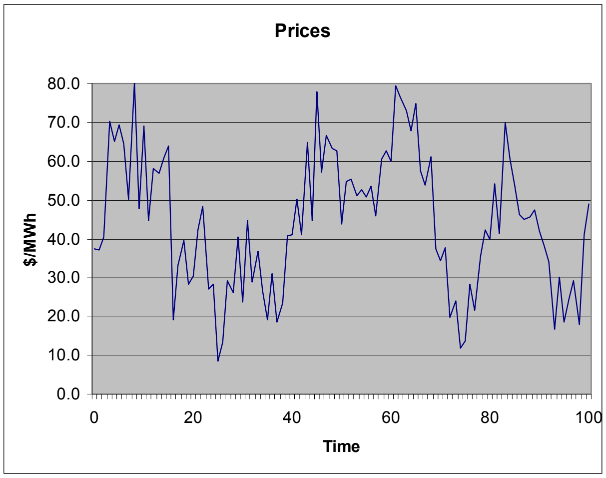


Figure L-118: Prices

Start by choosing a period with a representative distribution of prices (cost-effectiveness levels). This example assumes that prices are stationary over the long-term but have some variation around the average. Figure L-118 illustrates prices that this example will use, and Figure L-119 shows the frequency distribution of these prices. The period chosen, by definition, has prices representative of future periods, as Figure L-120 suggests. In Figure L-120, we take the effective life of the conservation measure to be some multiple, N, of this period. Over periods 2 through N, this example assumes that the distribution of prices, if not identical to that in the first period, has the same average as that in the first period.

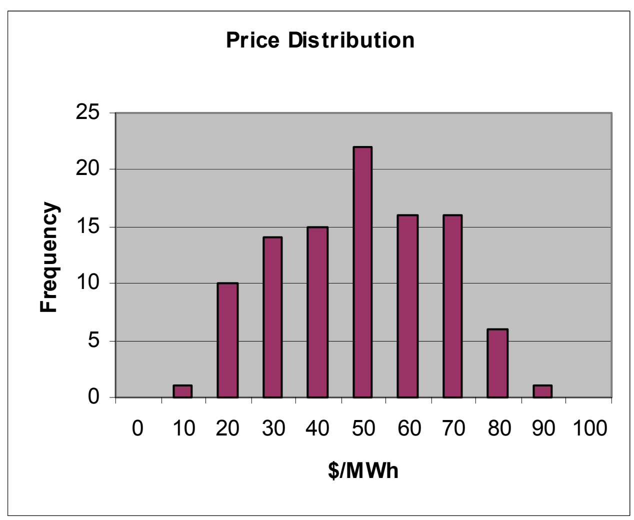


Figure L-119: Distribution of Prices

The conservation is a lost opportunity measure. In each period, potential conservation acquisition is represented by the supply curve in Figure L-121. This

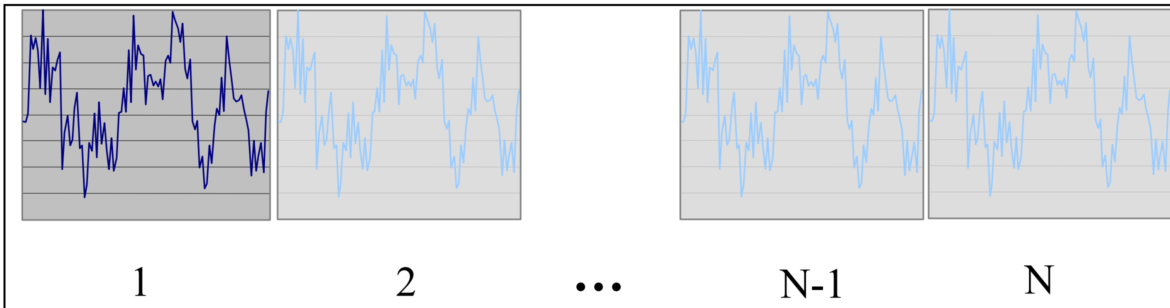


Figure L-120: Prices over Time

appendix's section "Supply Curves" details the technique for computing the amount of energy and the real levelized cost for the conservation from this supply curve.

During the period we have chosen, the example gatherers energy and cost according to the supply curve. In Figure L-122, the rate of acquisition of cost in the upper graph and of energy in the lower graph varies directly with the price. We note that the cost acquisition rate seems to be more sensitive to price variation than the energy acquisition rate, especially during periods of low prices, such as that identified as subperiod B in the figure. The energy and real levelized cost are present through the effective life of the conservation, which in this example we assume is identical to the economic life.

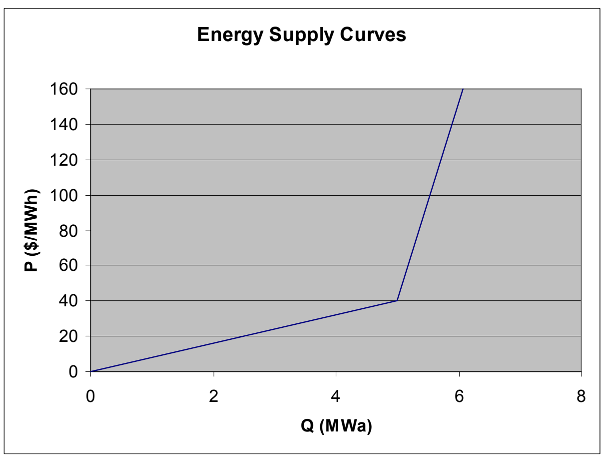


Figure L-121: Supply Curve for Conservation

The gross conservation value associated with the selected period is the sum of the acquisition rates over the selected period (just the cumulative height of the stacked acquisitions), times the average market price, times N-1. To see this, recall that the average market price over each of the N periods is identical, as Figure L-123 suggests. If the prices in period N are identical to those in period 1, the value the remaining life for each cohort *in* period N is unchanged *if moved to period **1***, as illustrated in Figure L-124. Note also that the *order* of the prices in period 1 does not affect the value, only the *distribution*. It is immaterial whether the process begins with a high or a low price.

A similar argument shows that the total cost of conservation acquired over the selected period is the sum of the acquisition rates for cost over the selected period, times N-1. The net benefit of conservation acquisitions over the selected period would then be the gross value minus this cost.

One of the assumptions this example makes to simplify calculations is that money has no time value. This example does not discount any of the cash flows.

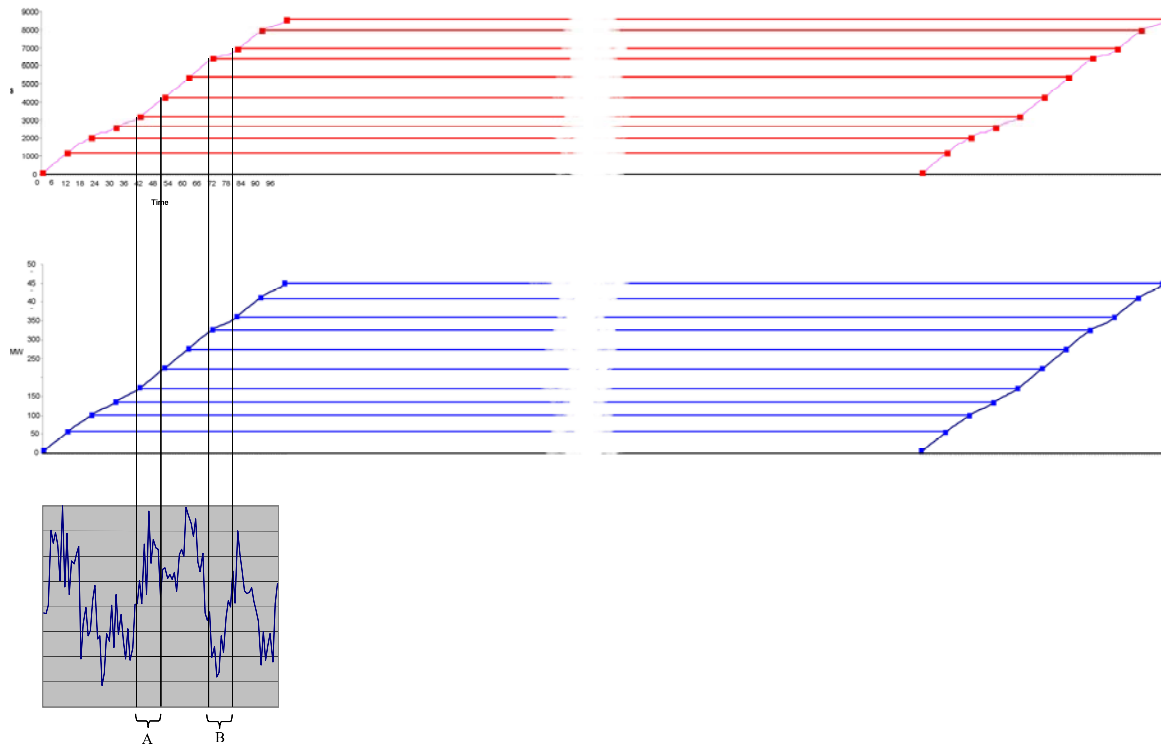


Figure L-122: Conservation Additions

We can summarize the above calculation of the net benefit of conservation acquisitions as follows:

$$V = \overline{p}\Delta q - \Delta c$$

where

$\overline{p}$ is the average market price

Δq is the cumulative increase in quantity

Δc is the cumulative increase in cost

These considerations demonstrate that gross value and cost of conservation acquired over the selected period are both proportional to the sum of the acquisition rates over the

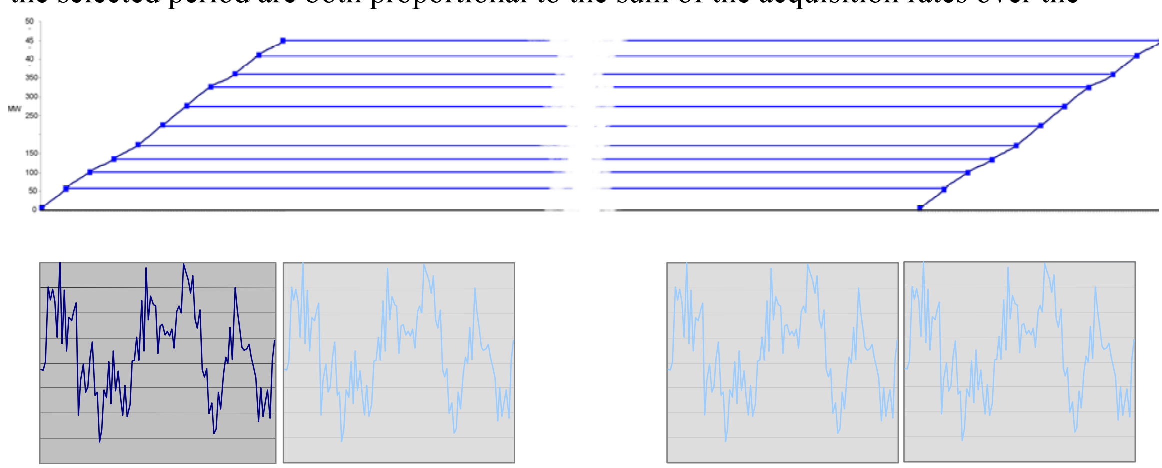


Figure L-123: Value of Conservation

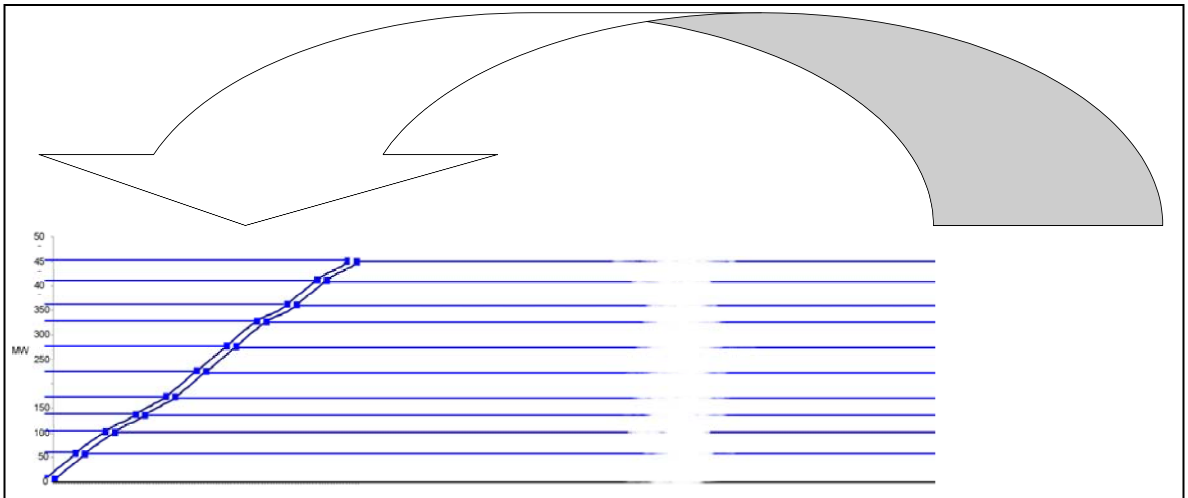
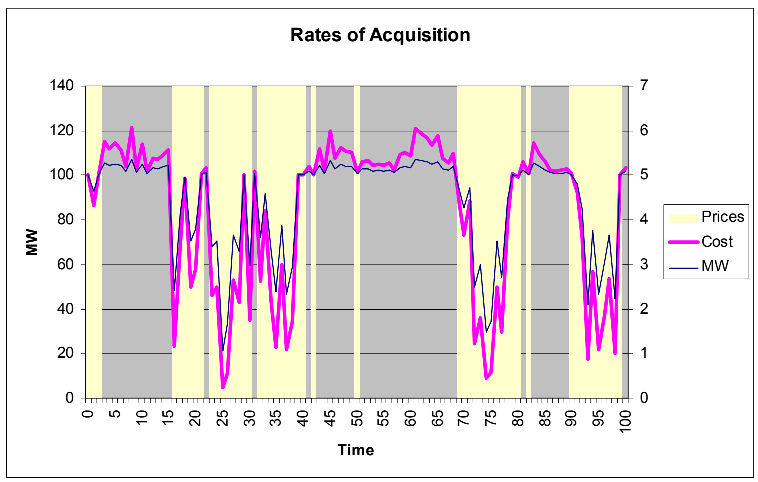


Figure L-124: Rearranging the MW

selected period. (The net benefit, of course, involves the average market price and is not so easily characterized.) Figure L-125 illustrates the rates of acquisition for cost and megawatts over the selected period. In this figure, the subperiods with prices that are below average are highlighted. As we would expect, cost and acquisition rates are much lower during these periods. We also note that the variation in the rate is much greater during subperiods of lower than average price.



Now consider the effect of the policy to acquire conservation up to 10 mills per kilowatt hour over market prices. The corresponding acquisition rates for costs and energy appear in Figure L-126. The policy of paying over market applies to all prices, including higher prices. What is striking, however, is that the acquisition of costs and energy during periods of high prices changes very little, while acquisition rates increase dramatically

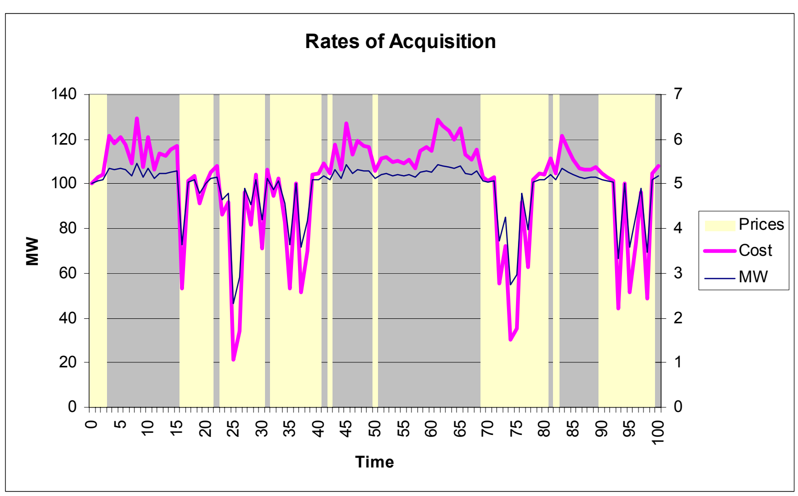


Figure L-126: Acquisition with 10 mill/kWh Adder in times of lower prices. The differences in acquisition rates for energy and cost under the policy are highlighted in Figure L-127and Figure L-128, respectively. This behavior corresponds roughly to that in the example in Figure L-116, which opened this section.

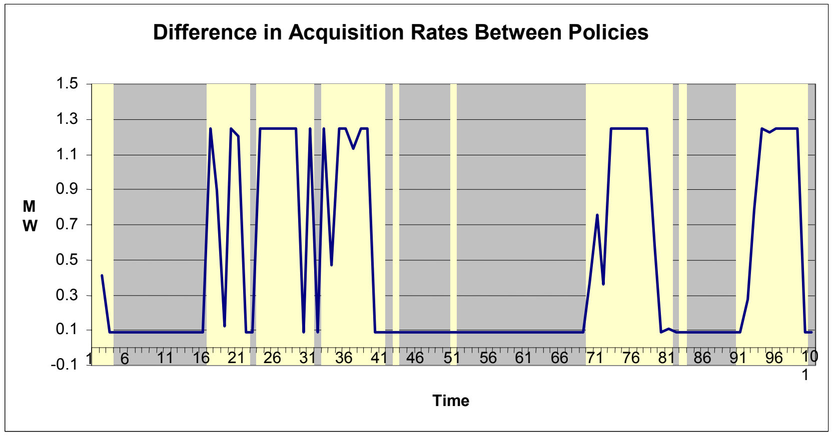


Figure L-127: MW Difference with 10 mill/kWh

Summing up rates of acquisition corresponds to finding the area under the curves in Figure L-125 and Figure L-126. Without the premium, cumulative energy acquisition is 449 MW, and cumulative cost acquisition is $8,553 per period. The average cost is 19.05 mills per kilowatt hour, about half of the average price for electricity, 44.36 mills per kilowatt hour. With the 10-mill premium, the cumulative energy and cost of course go up. The cumulative energy acquisition is 494 MW and the cumulative cost acquisition is $10,047 per period. The average cost increases to 20.33 mills per kilowatt-hour. Because we have acquired so many more megawatts at prices well under the average market price, however, the net value of conservation under the policy is greater. The net value of the policy is $520 per period, of 4.6% gain.

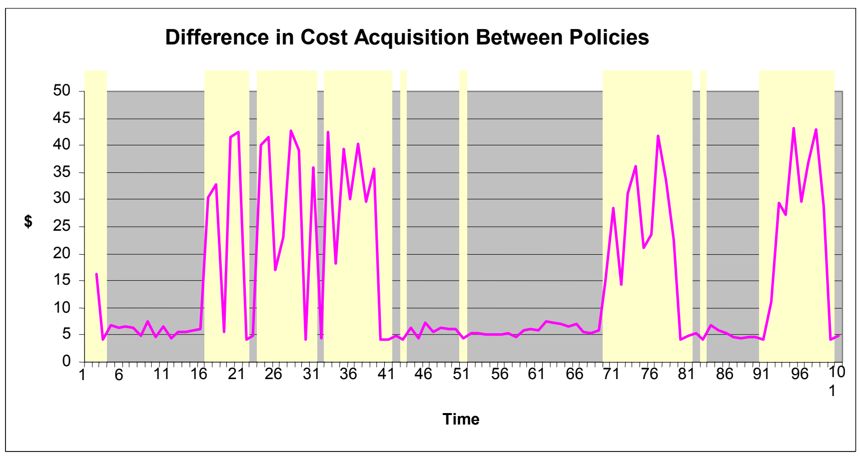


Figure L-128: Cost Difference with 10 mill/kWh

It is important to emphasize that the assumptions in this example are simple and not necessarily representative of existing circumstances. The purpose of this example is only to demonstrate how the shape of the supply curve could produce savings with a policy like the one this example uses. If the supply curve in this example were linear, there would be no net benefit. (Those readers who are becoming conversant in the supply curve cost computations will find the argument in Figure L-129.) Both supply curve non-linearity and uncertainty in cost-effectiveness levels are necessary for this effect.

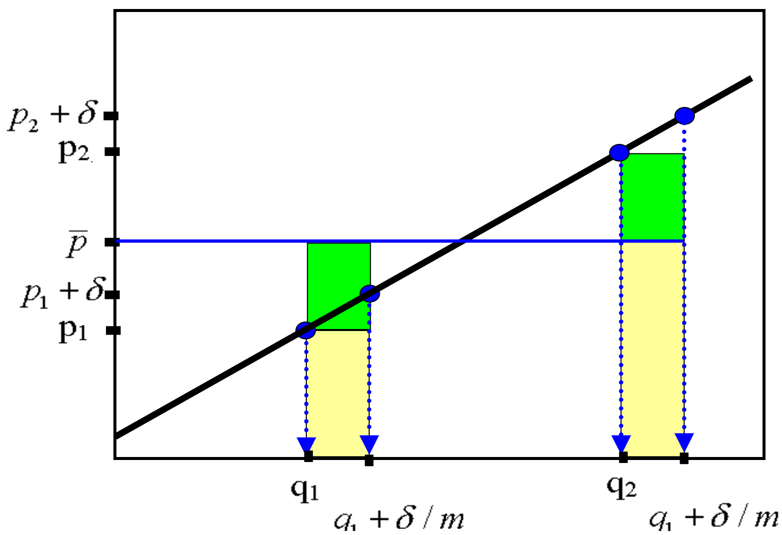


Figure L-129: Comparing Cost Areas

Olivia

On February 6, 2002, the Council released Document 2002-01, "Issues for the Fifth Power Plan." This document solicited comments from the industry on issues that the Council was considering for inclusion in the plan. The first among these issues was, Incentives for Development of Generation:

> "The current market structure appears to have failed to provide adequate and timely incentives for adding new capacity to ensure power supply adequacy and to moderate price volatility. The Council proposes to assess existing incentives and disincentives for development of new generation and examine options available to encourage development that will moderate potential supply demand imbalances and price volatility. Options will be analyzed to determine their effect on prices, system costs, adequacy and reliability. If appropriate, the plan may recommend measures to address systematic problems or improve signals for market development."[41]

The Council considered possible incentives for new capacity and the issues each approach raised. Apart from the questionable efficacy of the various approaches, key

[41] Page 2 of NPPC Document 2002-01.

questions plagued all of the approaches, specifically who should be responsible and how can that responsibility be enforced? The Council was particularly cognizant of the limited formal authority granted to the Council by statute.

One approach that emerged during discussions of the regional portfolio model was to empower individual utilities to make resource selection decisions that reduce their risk and cost. This approach recognized the diverse and independent decisions that utilities make. It assumed that the real leadership the Council exercises stems not from the formal authority of the Council, but from the quality and objectivity of its ideas, data, information, and methods. Utilities have built and acquired resources to meet their own needs, subject to the approval of their commissions and boards. Their requirement for new capacity, not markets for capacity or administrative requirements, drove the demand for new power plants, including those constructed by IPP's. Arguably, utilities have always attempted to incorporate risk assessment into their resource acquisition decisions. Each utility approached risk somewhat differently, however, and consequently few standards have been forthcoming. This made communication with boards and commissions difficult. By providing these parties with concepts, methods, and tools for assessing risk and for assessing the risk mitigation value of resources, the Council would achieve the goal of improving regional reliability by empowering individual utilities to acquire resources that reduce their own risk. These concepts, methods, and tools might eventually lead to standards that would facilitate communication around risk management issues.

Ideally, the Council could hand its portfolio model to utilities and other interested parties. The regional model, however, is an Excel workbook. The selection of this platform makes it possible for those who wish to understand and reproduce the Council's results to do so easily. The associated transparency is consistent with the statutory objectives of the Council. The disadvantages of an Excel workbook, however, are several. If not carefully designed, a workbook will recalculate very slowly. A more serious problem is the structural inflexibility of calculations in a worksheet. For example, changing resources, redefining periods, modifying subperiods, and changing the attributes of resources can require significant restructuring. A utility that wanted to use the logic of the regional model to represent its system would probably need to rewrite the workbook. Because dozens of the workbook macros interact with the worksheets, a non-expert would likely introduce errors into the operation of the model.

To address these concerns, the Council designed Olivia. Olivia is a computer application, illustrated in Figure L-130, that writes workbook portfolio models. The user can characterize his utility's loads and resources, markets for electricity, imports and exports, and other relevant features with simple and high-level parameters. For example, he can type the monthly average energy by subperiod into a column of an Excel worksheet, and paste this into Olivia's database. He can define subperiods within a period and stipulate the number of hours in each. He can characterize a generation resource in terms of its capacity, heat rate, variable operation and maintenance, and most of the other parameters with which individuals who use production cost models are already familiar. He can specify correlations among sources of uncertainty and the kind of stochastic processes he wishes to use to represent the sources of uncertainty. Finally he can specify aspects of the portfolio model such as the layout, the cost and risk criteria he wishes to use, the utilities he would like included in the workbook (described in the previous section, "Portfolio Model Reports And Utilities"), and whether they should be accessible through a new menu bar in the workbook model.

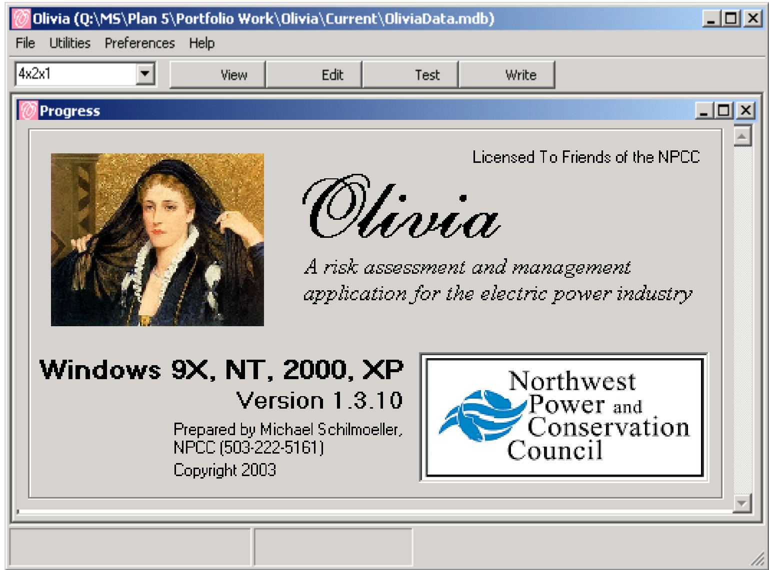


Figure L-130: Olivia

After pasting these data into Olivia's database, the user presses a button and Olivia writes the workbook. The workbook contains not only the data and formulas that the user specifies, but also any macros that the portfolio model needs to perform the simulation. Significantly, this workbook contains only those calculations and macros that this user requires, and no more, despite the richness of options and representations that Olivia can provide to users who need them. This keeps the workbook small and calculation as fast as possible.

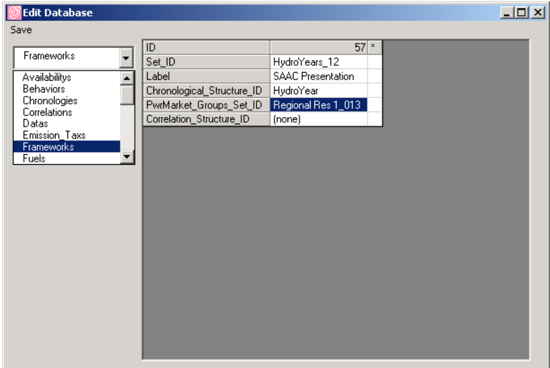


Figure L-131: Editing Olivia's Database

Olivia has editing features that make it easy to modify a portfolio model. The user can make these edits permanent or make edits to a "clone" of the model. Unless the user specifies otherwise, any updates to a model will automatically update all clones. This eliminates the potential for "revision sprawl" and models becoming de-synchronized. (See Figure L-131.) The editing interface features referential integrity, which guarantees that fields link to valid fields in other tables. (See Figure L-132.) There is also a utility that permits the user to test any changes he has made to a model to assure that they are legal and Olivia will interpret them properly.

This section is not a complete description of Olivia. As of this writing, Olivia is not in full production, although a version of Olivia extant in December 2003 produced the regional model used for this plan's analysis. The Council intends to release a production version of Olivia in Spring of 2005 and hold classes on its use shortly thereafter.

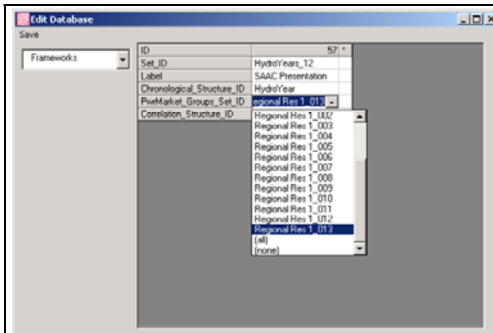


Figure L-132: Referential Integrity

Glossary

American option – an option that may be exercised up to expiration. (See European option, put option, call option.)

assumption cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains a value defined by a probability distribution's random variable.

availability – maximum power plant production, derated for planned outages (maintenance), but not forced outages (MW-period). Availability is synonymous with capability. Because the regional model expresses plant availability in average MW, maximum production is average capacity (MW).

call option – the right to buy the underlying asset by a certain date for a certain price.

capability – see availability.

CCCT – combined-cycle combustion turbine. A natural-gas fired combustion turbine that extracts additional efficiency from the turbine by capturing waste heat to create steam that assists generation. (See SCCT.)

CDF – Cumulative Distribution Function or Distribution Function. A function that specifies the probability that a variable's value falls at or below a given value.

cohort – a group has some descriptive factor, such as age, in common. In the regional model, all plants of a given type, e.g., SCCT, that are ready for construction in the same period are cohorts. They will respond to changing circumstances the same way and will remain in the same stage of development, production, or retirement throughout their lives.

Concept of Causality – relying on conditions that are strictly in the past (prior periods) to determine behavior in the current period.

DCF – discounted cash flow. A standard technique for the economic evaluation of projects, given the projects' associated cash flows. DCF analysis uses future free cash flow projections and discounts them to arrive at a present value, which is used to evaluate the potential for investment. Most often, DCF discounts cash flow at a weighted average cost of capital.

decision cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that the user controls. The reader may think of the value of these cells as representing the plan. The optimization program adjusts the decision cells in the regional portfolio model to minimize cost, subject to risk constraints.

distributed computation – partitioning computation into subtasks that are parceled out to several machines for processing and then reassembling the results in a manner that makes the final computation indistinguishable from that obtained from a single computer. Also referred to as "parallel processing."

dollars per kilowatt-standard year ($/kWstdyr) – the standard unit of fixed costs in the portfolio model. A standard year consists of standard months of exactly four weeks. (See "standard periods," below.) If a calendar year has 365 days, the $/kWstdyr is 336/365 or about 92 percent of the value of a project's $/kWyr. (See sections "Single Period" and "New Resources, Capital Costs, and Planning Flexibility" for discussions of standard periods and their use.)

DR – demand response. The voluntary curtailment of load, typically in response to prices. See chapter four and appendix H of the plan.

DSI – direct service industry, the community of industries that historically have been direct service customers of the Bonneville Power Administration. Aluminum smelters are a conspicuous DSI in the Pacific Northwest.

effective forced outage rate (EFOR) – percent of time that a power plant or other productive service is expected to be unavailable, due to unforeseen problems.

elasticity – The percent change in demand for a commodity divided by the percent change in the commodity's price

Energy Content Curve (ECC) – An operating guide to the use of storage water from reservoirs operated by parties to the Pacific Northwest Coordination Agreement. Gives 95 percent confidence of reservoir refill, given (projected) water conditions. The variable energy content curve (VECC) is the January-through-July portion of the energy content curve, based on the forecasted amount of spring runoff.

energy reserve margin – resource energy surplus to requirements. Unless otherwise qualified, this refers to the hydro year surplus in MWa (MW-years), assuming critical water hydrogeneration levels.

European option – an option that may be exercised only on the expiration date.
exchange option – an option to exchange a quantity of one asset, such as an mcf of natural gas, for another, such as a kWh of electricity.
feasibility space – a metric-free set of ordered pairs, where each pair represents a plan and the values of the two entries reflect the cost and risk of the plan. There is no metric because cost and risk typically are measured differently and are not comparable. Nevertheless, there is an efficient frontier of plans that are not dominated by other plans. (A plan is dominated by any plan with *both* lower risk and lower cost.)
forecast cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains statistical output of the model. The default color for these cells is turquoise. In the regional model, the primary forecast cell is the NPV cost for a plan under a 20-year future. Other forecast cells in the regional model, such as those that regional model macros assign risk values, serve to communicate data back to the OptQuest optimizer.
future – In the context of the regional model, a future is a set of circumstances over which the decision maker does not have control, such as requirements for electricity, prices for fuel, and stream flows that determine hydroelectric generation. (Appendix P addresses the complete list of uncertainties that give rise to a future in the regional portfolio model.) A set of samples for each of these, specified hourly over the 20-year planning horizon, comprises a single future.
GRAC – The Council's Generation Resource Advisory Committee
GTC – green tag credit. See Chapter 6 for a description and history of green tag credits.
IGC, IGCC – Integrated Gasification of Coal or Integrated Gasification Combined Cycle. A process for converting coal to gases suitable for combustion in power plants
IC – integration cost. Refers to costs necessary to integrate electricity from a power plant into an electric power system. Typical sources of cost are back-up or firming, shaping, and storage.
IPP – independent power producer. Synonymous with non-utility generation (NUG).
load-resource balance – see resource-load balance.
macro – a computer subroutine.
Monte Carlo simulation – Any method which solves a problem by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems which are too complicated to solve analytically. It was named by S. Ulam, who in 1946 became the first mathematician to dignify this approach with a name, in honor of a relative having a propensity to gamble (Hoffman 1998, p. 239). Ulam was involved with the Manhattan project to build the first atomic bomb, where physicists used the technique for evaluating complex integrals.
MWa – An average megawatt, typically the energy equivalent to one megawatt-year, although occasionally used rather loosely to refer to the average power rate (MW) over whichever period (day, month, quarter) is under discussion. Where it is important to avoid ambiguity, the appendix refers to the energy as a MW-year (MWyr), MW-month (MWmo), MW-quarter (MWqtr), and so forth.
NIPPC – Northwest Independent Power Production Coalition

O&M – operation and maintenance. When referring to the associated cost, may be either fixed (FOM) or variable (VOM).

On-peak, off-peak – refers to subperiods of loads and prices that are typically higher and lower, respectively. The regional model subscribes to the convention that on-peak hours are hours 7 through 22 (6AM to 10PM), Monday through Saturday, excepts for NERC holidays. Any hours that are not on-peak are off-peak. Because the regional model uses standard periods (see below), however, the model does not need to address variation due to days per month, Sundays per month, and holidays per month in cost and energy computation.

plan – The meaning of the term "plan" must be determined from context: 1) In the context of the regional model, a plan is that over which the decision maker has control, such as the siting and licensing schedule, earliest construction dates, and size and type of generation. In the regional portfolio spreadsheet model, the values of the worksheet's decision cells determine the plan. See the section "Parameters Describing the Plan" for a detailed description and explanation. 2) In the larger context, it may refer to the Council's Fifth Power Plan, either the Action Plan or the plan for resources beyond the five-year Action Plan.

put option – the right to sell the underlying asset by a certain date for a certain price.

PNUCC – Pacific Northwest Utility Conference Committee

production tax credit (PTC) – See Chapter 6 for a description and history of production tax credits.

resource-load balance – No standard definition of this term exists in the industry. In the context of this appendix, resource-load balance refers specifically to energy surplus to requirements on a hydro-year basis, assuming critical hydro water generation and weather-adjusted average load.

risk – No standard definition of this term exists in the industry. In the context of this appendix, risk always refers to the expected severity of *bad outcomes*. TailVaR_{90} (see below) is the principal screen for risk in the regional portfolio model, although Council analysis considers other source of risk such as annual variation in power costs and exposure to market prices. This definition means predictability or uncertainty of costs, as measured by standard deviation, would not be a risk measure. (See the discussion of risk measures in Appendix P.)

RL costs – real levelized cost. See section "Real Levelized Costs," beginning on page L-16, for a detailed discussion.

SAAC – The Council's System Analysis Advisory Committee.

SCCT – Single- or simple-cycle combustion turbine. (See CCCT.)

scenario – a particular plan under a particular future. See the definitions of "plan" and "future."

spinner graph – A collection of Excel graphs display the data for a scenario, including values for all sources of uncertainty in each period. The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period and for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs." See section "Data Extraction And Spinner Graphs," beginning on page L-117, for details.

standard period, standard month, standard quarter, standard year – any period based on the standard month, which has exactly four weeks (1152 on-peak hours, 864 off-peak hours). There are three standard months per standard quarter and four standard quarter (12 standard months) per standard year. See section "Single Period," beginning on page L-11, for details.

TailVaR_{90} – The average of the ten percent worst outcomes. In the regional model, the outcomes are NPV 20-year system costs for operation and forward-going fixed cost, including that for new construction. See Appendix P for details.

Twilight Zone, TLZ – a region in the regional portfolio model where computations typically are iterated several times for each subperiod or region. See section "Logic Structure," beginning on page L-6, for a more specific description.

UDF – A Microsoft Visual Basic for Applications (VBA) user-defined function. These inhabit worksheet code modules, workbook code modules, and VBA standard modules (in contrast with VBA class modules). All regional portfolio model UDFs occupy standard modules.

valuation cost estimate – A technique for computing variable costs by referencing the gross value of each resource and the gross cost of meeting requirements to the price for marginal purchases and sales. The standard price used in the regional portfolio model is the wholesale market price for electricity. See section "Valuation Costing," beginning on page L-13.

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1 Glover, F., J. P. Kelly, and M. Laguna. "The OptQuest Approach to Crystal Ball Simulation Optimization." Graduate School of Business, University of Colorado (1998). Available at http://www.decisioneering.com/optquest/methodology.html ;
M. Laguna. "Metaheuristic Optimization with Evolver, Genocop, and OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/comparisons.html; and
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2 Jeff King, NPCC, Tuesday, 4/4/2005 11:12 AM, email Subject: "RE: Appendix L," attachment AppL_050311JKcmts 040405.doc. "Perhaps unfortunately, the levelized cash flows that I supplied were based on a constant mix of developer (20% COU, 40% IOU and 40% IPP), and levelized using the blended after-tax cost of capital of these (4.9%). The resulting levelized fixed costs for a conventional coal and wind plants are about 9% and 4% greater, respectively, using these assumptions (the per MWh difference would be less because of the lower capacity factor of wind). – JK"

3 Direct Calculation of Expected Value.doc

4 Deriving_option_greeks.TIF and Derivative of call wrt strike.TIF

5 The value of 6000MW was established by Council Staff analysis of intertie loadings. See, e.g., Dick Watson, intertieloading.xls, August 13, 2004.

6 Terry Morlan, Ph.D., NPCC, Wednesday, June 23, 2004, Notes_L14.doc.

7 Worksheet qry_041101_AppM_02 of Appendix M_04.xls

8 Original Geneys model output is in System.out. The same subdirectory holds all the Genesys input and output files. See also Notes on comp_040626.doc for fundamental information about the database and queries and Notes.doc and Notes_Update_041103.doc for revisions. The database Appendix M.mdb and it successors are spawned from the comparison database, Comparison_040626.mdb. This latter database was originally in the subdirectory ..\Portfolio Work\Olivia\Calibration and Verification\Loads & Resources (LR) Studies\Portfolio vs LR balance 031030.

9 Jeff King, NPCC, Tuesday, April 27, 2004 5:15 PM, *email* Subject: "GEBESYS genres list," [SIC] attachment FOR_040502.xls

10 Worksheet "tbl_041110_Resources_in_L25" of Appendix M_04.xls

11 Worksheet "Calc RPS" of Appendix M_04.xls

12 Worksheet "IPP calculations" of Appendix M_04.xls

13 MJS_Comments_041116.doc

14 Worksheet "New Resources" of Appendix M_04.xls

15 Worksheet "Construction Costs" of ConvertingOvernightToPeriodCosts_v06.xls

16 The original energy allocation are from the workbook AllSectorSupply.xls worksheet "All Sector Supply," from Tom Eckman, Fri 1/16/2004 5:17 PM, email "Conservation Supply Curve Data." These calculations are from L8.xls (see Notes on L7.doc). See also Conservation Energy Allocation Reconstructed.xls for the simplified calculation that appears in this appendix.

17 Workbook AllSectorSupplywithSysTDValue_L21.XLS

18 Contracts data originally from Tim Misley, BPA, *email* Friday, August 27, 2004 3:22 PM, subject: "RE: Conversation with Tim Misley." Figure data from MSchilmoellerRegionalContracts_MJS.xls. The computation of the MWa for the regional portfolio model is in the worksheet "Contracts for Portfolio Model". Most of the data that went into preparing the workbook derives from the database Contract Data_03.mdb. See the database table "## Comments and Instructions ##" for an embedded MS Word document describing the more technical data transformations.

19 Workbook States.xls permits a user to calculate the number of states for the choices available. It accounts for the reduction in the number of states for the constraint that no plants may be "un-built" after construction.

20 See, for example, Paul Komor, Platts Research and Consulting, "Hedging Energy Price Risk with Renewables and Energy Efficiency," ER-04-12 Strat, September 2004.