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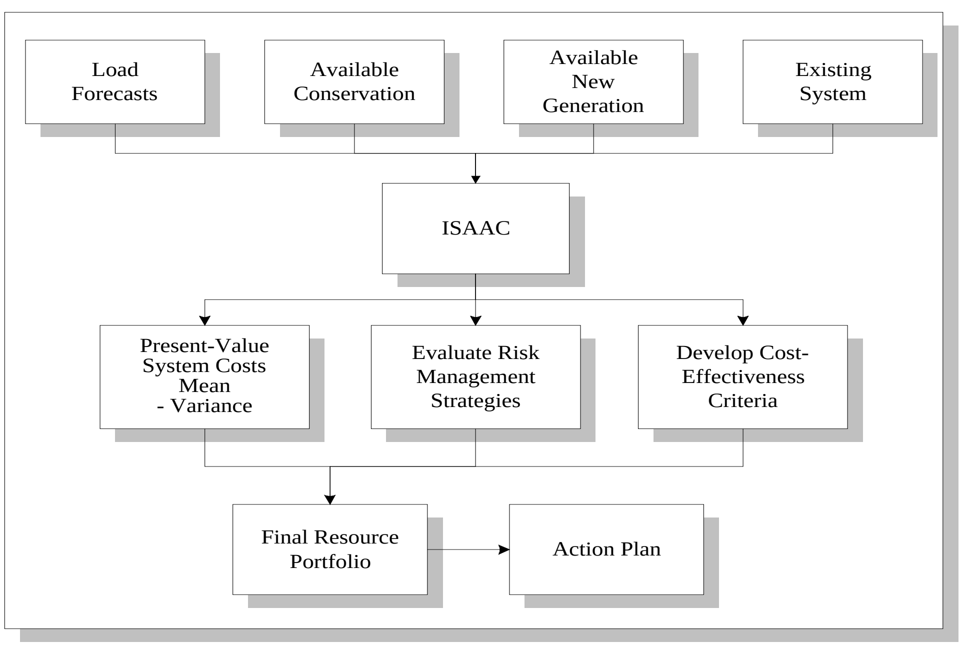
DESCRIPTION OF RESOURCE ANALYSIS MODEL - ISAAC

INTRODUCTION

This chapter describes ISAAC, the computer model the Council uses for analysis of resource cost-effectiveness and the quantitative treatment of uncertainty. ISAAC is an acronym for "The Integrated System for Analysis of Acquisitions" and was originally developed in the late 1980s by staff from the Council, Bonneville Power Administration, and the Intercompany Pool, with support from the Pacific Northwest Utilities Conference Committee. It is currently maintained by the Council, and is the principal tool for evaluation of the various resource portfolio issues addressed in this plan. Volume II of the Council's 1991 Power Plan also contained a chapter documenting ISAAC, and some of that material is repeated here. However, the model has undergone significant revision since then and is described comprehensively here.

The task of system analysis in the Council's plan is to forge a multitude of planning assumptions into a preferred strategy for the region's electricity future, and more importantly, to determine what near-term actions need to be taken to prepare for that future. The planning assumptions include forecasts of demand for electricity, the cost and availability of new sources of electricity generation, and the cost and availability of electricity conservation measures. System analysis compares the forecast of demand with the capability of existing power system resources in order to determine the need for additional generation or conservation resources in the future. Figure H-1 illustrates the components of the analysis. If future electricity demand and resource capabilities and costs were known with certainty this would be a relatively straightforward problem. However, the future is inherently uncertain. We cannot know with assurance the future economic growth of the region, the future price of energy sources, what technological developments will occur, or future rain and snowfall levels.

Figure H-1
Council Resource Analysis Process



ISAAC uses a modeling approach that combines features of "Monte Carlo simulation" and decision analysis. Monte Carlo simulation is a technique used to incorporate uncertainty by using a mathematical model of a system with uncertain elements to make repeated experiments on that system. It can be used to build quite complex models of real-world systems. Decision analysis is a branch of operations research involving the evaluation of decisions in light of uncertain future events. It can provide insights into the range of consequences for a decision, and can be particularly helpful in arriving at decisions that balance the sometimes-conflicting objectives of reducing both cost and risk. This is the focus of the quantitative problem addressed with ISAAC. Given the complexities and future uncertainties surrounding the Northwest power system, what set of policies and resource actions can provide the best tradeoff between cost and risk?

The effect of uncertainty in important variables for the Northwest power system is addressed by randomly selecting an assumption for each from either a forecast range and associated probability distribution, as in the case of electricity demand and fuel prices, or from historical experience as is the case for water conditions. The selection of values through the study period for each of the uncertain (or stochastic) variables defines a specific scenario or game. For each game, the model simulates resource decisions that might be made in the absence of perfect foresight about the future path of the uncertain variables. Cyclical variations and imperfect forecasting of the future result in resource decisions that seldom turn out to be optimal when the actual path through the future is revealed. These planning errors result in costs being incurred either from imbalances in supply and demand or in less than optimal resource decisions. This type of analysis makes it possible to explore resource strategies that are less heavily penalized by errors than others.

By exploring many, typically hundreds, of scenarios or games that collectively represent the range of uncertainty, ISAAC can be used to evaluate the average cost of alternative resource strategies. In addition, information is generated about the variation in cost and reliability that can result from uncertain future events. It is possible, for example, to identify one resource strategy that has a low expected cost but a lot of variation depending on the future path of fuel prices or demand growth. Such a strategy would leave the region's power system vulnerable to future events. Another resource strategy may have slightly higher expected costs but less exposure to future uncertainty. This analysis allows the Council to determine the value of resource characteristics such as short lead time, low capital cost, and small unit size, which all tend to moderate the risks inherent in an uncertain future. The value which derives from their flexibility characteristics is captured explicitly in the simulation.

MODEL OVERVIEW

An overview of ISAAC and the model process flow is shown schematically in Figure H-2. The major input categories are shown on the left. As mentioned earlier, an important set of inputs are the demand forecast scenarios that define the potential load range and the probability distribution for that range. Other categories of inputs include demand- and supply-side resource alternatives, their supply distributions and constraints on rates of development, the physical and economic characteristics of both new and existing resources, data characterizing the variability of the Northwest hydropower system, the nature of out-of-region bulk power markets, and financial data for potential resource sponsors. To control the resource development activity for a study, the user can either specify a resource strategy that generally defines the types of resources preferred, or specify a dynamic system expansion option, where the model automatically adjusts the resource strategy in response to changing resource economics.

During the course of a study, samples are taken for the uncertain variables that are active for the study. In the current version of ISAAC, variables that can be treated stochastically include:

- Electricity demand.
- Pacific Northwest and British Columbia hydropower conditions.
- Fuel prices.
- Southwest spot market prices.
- Thermal and hydro unit forced outages.
- Intermittent generating resource output.
- Plant siting and licensing success.

- Conservation and generating resource supply availability.

The user defines which of these variables should be modeled as uncertain for a specific study. It is possible to turn off all the uncertainty in a study and use the model in a straight scenario analysis mode.

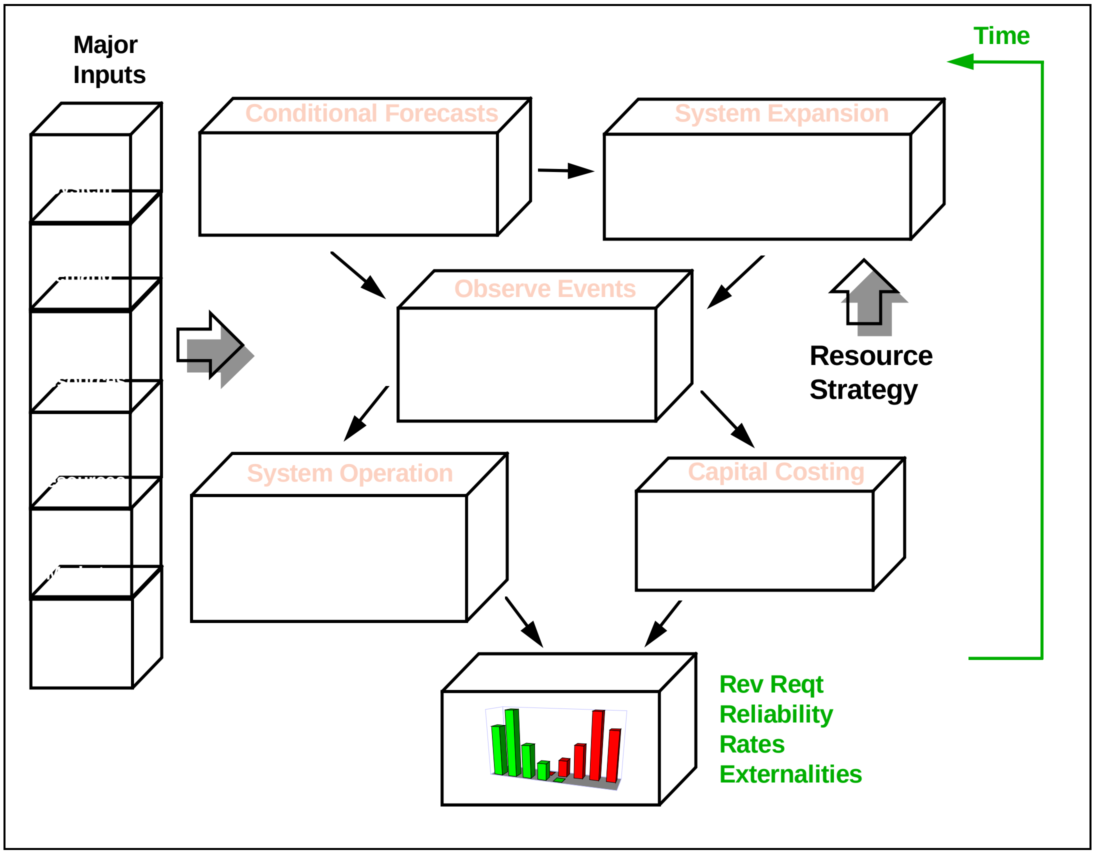
At the beginning of each game the model randomly generates a future load path the using the range data and probability distribution for the demand forecast. It then moves through the future along this random load path, forecasting and making resource decisions as consistently as possible with the resource strategy. It has no knowledge of the future and internally develops its own forecasts for demand, fuel prices, and resource supply based on the characteristics of original forecast ranges and events observed so far. These internal forecasts are used in conjuntion with the resource strategy to make decisions on the management of individual conservation programs, pre-construction or option decisions for generating resources, and construction decisions for generating resources.

During each year, the model samples for observed conditions for each stochastic variable. As in the real world, the observed values for forecast variables frequently turn out to be different than the predictions used when decisions were made. This can result in an observed load/resource balance that's different than the target, and resource economics that are less than optimal.

Costing routines keep track of the costs for the observed system conditions. A system operation module simulates the operation of the hydro-thermal system using observed conditions for load, resources, water and fuel prices and calculates regional production costs, as well as economy sales and purchases from out-of-region power markets. The system operation module also accounts for the environmental emissions from generating resources. A detailed financial module calculates the capital revenue requirement pattern for the resources that are developed. Retail rates are calculated, and if necessary, the load path is adjusted for price effects.

The model repeats the entire process for each year of the planning horizon. After one pass is completed, it will have simulated the effect of the resource strategy under one set of future conditions. Because of the large number of possible alternative futures, it is usually necessary to make many passes through the study period to ensure statistical reliability for the results. The outcomes of all the passes are compiled into a variety of reports describing the economic and physical results for selected variables. Reports are generated that describe not only the expected value or mean outcomes, but also describe the distribution of outcomes for important variables.

Figure H-2
Overview of ISAAC



The following sections describe some of the major features of ISAAC.

Treatment of Demand Uncertainty

One of the first steps taken by the model in a pass through the future is the creation of a load path for non-aluminum industry loads. This process is shown on Figure H-3. The four detailed load forecasts are used to define a trapezoidal probability distribution for long-term load growth. A random selection is made from this distribution and is used to calculate the observed load at the end of the planning horizon. Because the input load forecasts do not have constant load growth rates over the entire planning horizon, a trend growth pattern is determined to reflect the general time series structure of the forecast. Once this load growth trend has been developed, the trend growth rates are modified with a series of random shocks to introduce volatility into the load path. The parameters influencing the amount of volatility in the load paths are controllable by the user.

Figure H-3
Load Path Development

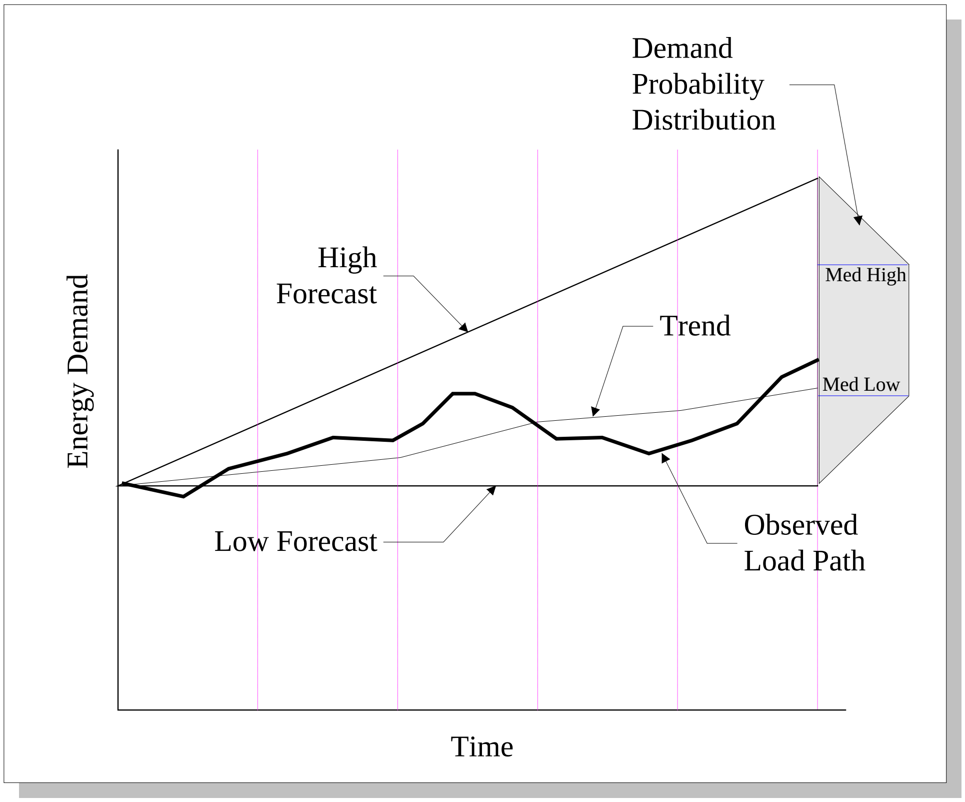
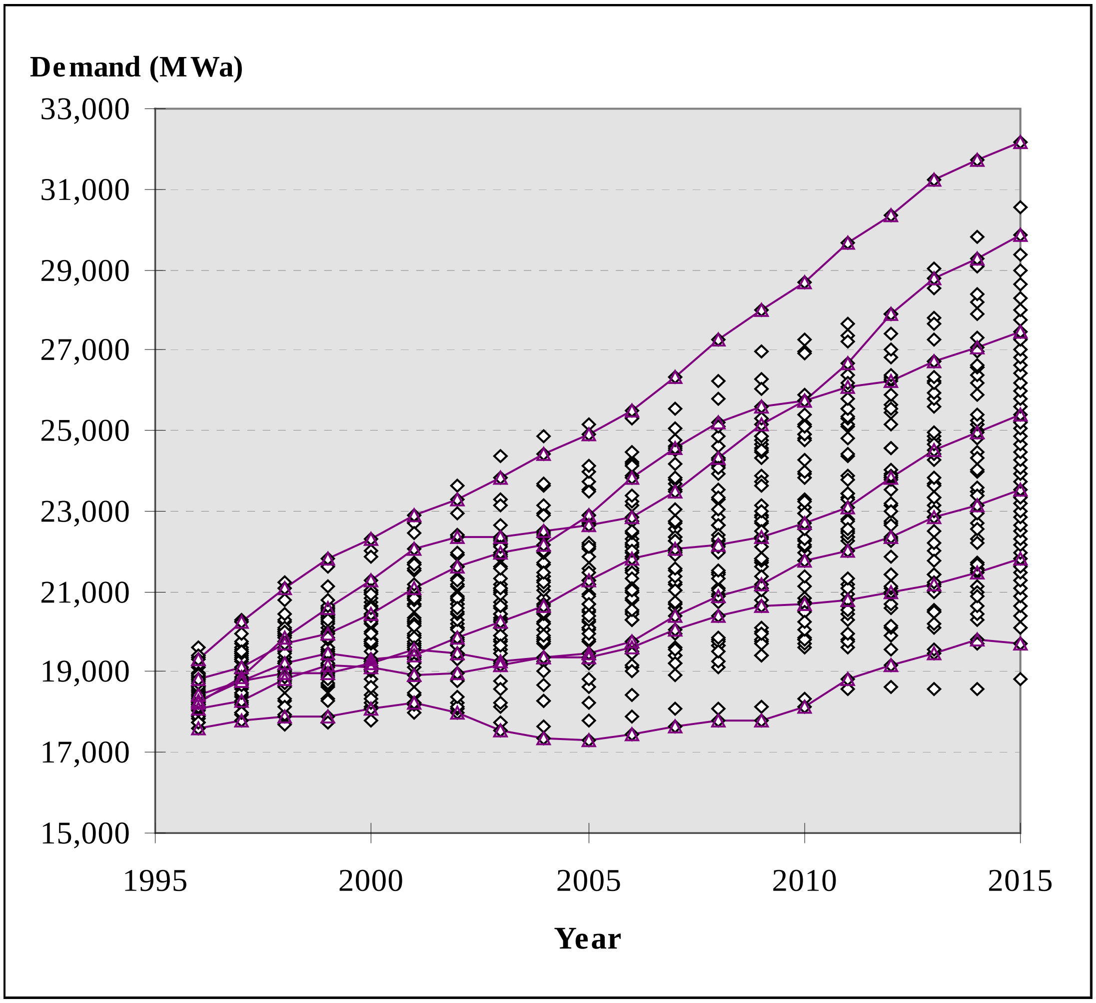


Figure H-4 is an illustration of the observed load paths generated by the model. It is a scatter diagram of regional non-aluminum industry load against time for a study in which only 50 load paths were generated. The Council typically uses 100 paths or more in an actual study. Each point represents a load level that the model will observe as it moves through the future. The solid lines represent a set of continuous load paths that would be followed by the model. Alternative load paths all start at a particular reference point, but may end up at any point between the low and high forecasts. The user has control over the size of the load range, the shape of the distribution of ending load values, and the amount of volatility present in the individual load paths. However, the model has only internal forecasts of where a load path eventually will lead. It has limited forecasting ability and continually updates forecasts as it moves through time, but it is blind to the future load within the limits of the forecast range. Forecast and observed loads are broken down into the loads required for utility planning activities, system dispatch and rate calculations, through a set of ownership and allocation matrices.

Currently in ISAAC, demand uncertainty effects only annual energy demand. The observed annual demand is shaped into monthly and daily load patterns for production costing and reliability analysis using load shapes derived from the Council’s hourly load forecasting system. The treatment of load chronology is discussed in the system operation and production costing description, which follows later.

Figure H-4
Sample Load Paths



Aluminum Industry Model

The other component of load uncertainty is that associated with the direct service industry aluminum smelter loads. ISAAC contains an aluminum industry sub-model that generates forecasted and observed values for direct service industry loads. This sub-model uses an aggregate picture of the aluminum industry in the Northwest, rather than focusing on individual smelters. The market price for aluminum is treated as a random variable. It is assumed to be normally distributed, with a user-specified, long-term mean and standard deviation. The level of aluminum load is driven principally by forecasted and observed prices for aluminum.

Loads are determined through two major components. The first is a long-run smelter capacity decision. It is made through a method that describes smelter capacity as a function of estimated present value of aluminum production profits. The upper and lower bounds for capacity and the parameters defining capacity as a function of net present value are user-defined. The actual amount of aluminum load is driven by a function that describes how much of the smelter capacity will be used based on costs of production and the price of aluminum. Aluminum load forecasts are done annually and are based on forecasts of aluminum price. These forecasts are used in the system expansion routines for acquisition of resources. Observed load levels are determined quarterly, and are based on observed prices for aluminum. The observed load levels are used in the system operation routines.

One thing to note about the aluminum load logic is that it produces loads that are largely independent of the level of regional non-direct-service industry load. This is a departure from the assumption in the detailed load forecasts, where high direct service industry loads accompany the high forecast, low loads accompany the low forecast, etc. In ISAAC, the assumption is that long-run aluminum prices are driven by world markets, and will be determined independently from regional economic conditions. While the pattern of correlation between direct service industry and non-direct-service industry loads differs from the detailed demand forecasts, the range of loads should not. ISAAC's aluminum sub-model is usually calibrated to result in approximately the same range of aluminum industry loads as contained in the detailed demand forecasts.

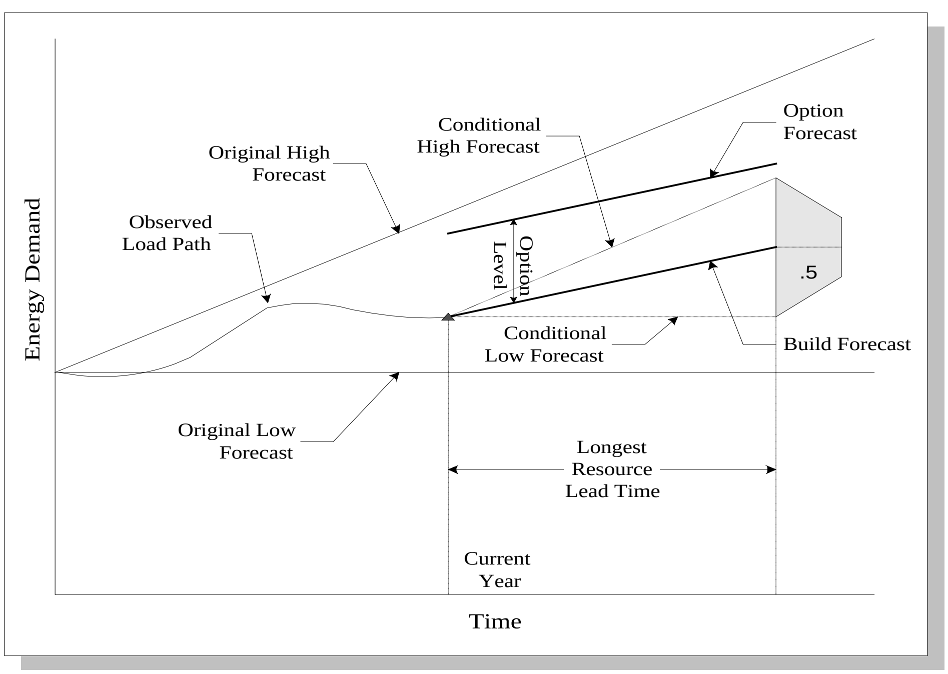
Option and Build Requirements

Two of the input parameters defining the resource strategy are the option level and build level. The option level governs the amount of resource for which options would be acquired and held in inventory. The build level governs the amount of resource moved out of inventory and into actual construction as well as the acquisition efforts for conservation programs. The option and build levels represent levels within the range of load uncertainty to use as guides for making resource decisions.

An example is shown in Figure H-5. In this example, the region has moved out along a somewhat random load path and finds itself at load level "L'' in time period "T.'' The future load path is still unknown, and decisions must be made in the face of this uncertainty. To do this, a range forecast is first made from period "T,'' and a probability distribution is applied to the forecast range. The length of the forecast corresponds to the longest lead time of available resources. The range of this new forecast range is likely to be narrower than the original range in the same time period. The high growth rate still is achievable, but because the model is now at a middle point in the range, it is very unlikely that it will ever reach the original high load path. Within this range, further forecasts must be made to use as a guide in making option decisions and build decisions.

Figure H-5

Option and Build Level Forecasts

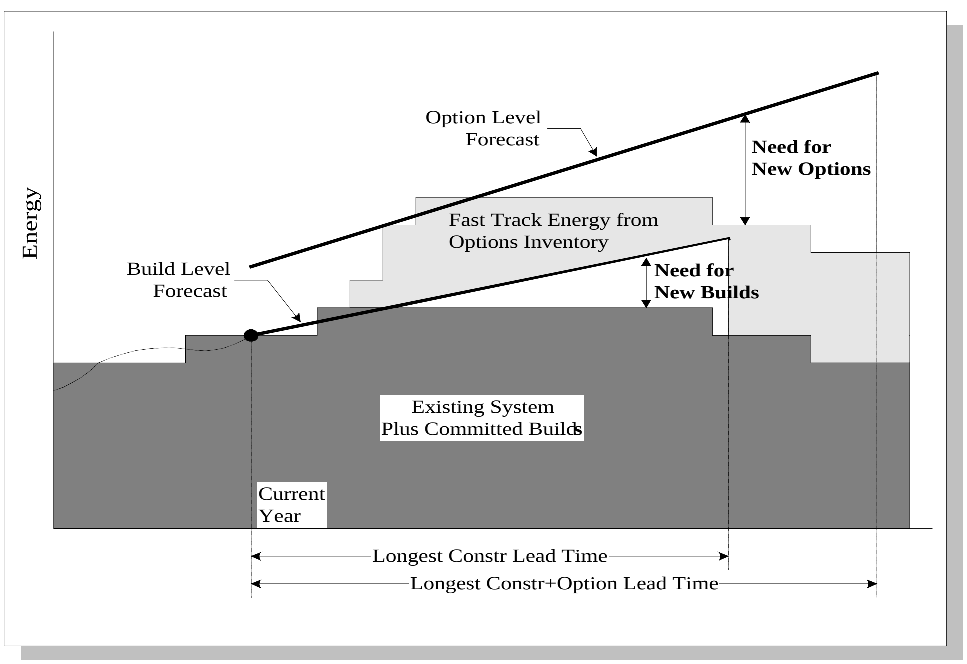


The approach shown here is to develop a 50-percent cumulative probability (median) forecast and add or subtract constant energy amounts to develop the option and build forecast. In this example, 1,500 average megawatts is added to the median forecast to generate the option forecast. The build level adjustment is zero, and the build forecast is identical to the median forecast. Another alternative for specification of the option and build levels is to use only cumulative probabilities within the conditional forecast range. For example a 90-percent option level would correspond to a forecast level that 90 percent of conditional load paths would be below. Once these forecasts have been made, a set of resource priorities is used to guide resource decisions. Conservation acquisition and generating-resource build decisions are guided by the build-level forecast. Generating resource option decisions use the option-level forecast as a target.

Resource Scheduling Decisions

The level of need for resource decisions is determined by comparing forecasts of system energy capability to the build and option level forecasts. Resource accounting routines are used to track the expected timing of arrivals for the set of conservation acquisition and generating resource option and build decisions that were made in previous years. Two resource capability forecasts are made. The first includes existing system resources, the expected energy from conservation acquisitions made to date, and the expected energy from prior generating resource construction decisions. Comparing this forecast to the build level demand forecast yields the forecast need for energy from new build decisions or conservation programs. The second resource capability forecast adds to the first forecast the potential energy resulting from resources currently in the option inventory or in the siting and licensing process, if put on a fast track to construction. Comparing this to the target option forecast yields the need for option decisions. This process is illustrated conceptually in Figure H-6. [1]

Figure H-6
Resource Requirements



[1] The system expansion logic used in ISAAC focuses on energy for resource scheduling decisions. Capacity considerations and the relative value of resources with differing capacity characteristics are reflected in the system operation and dispatch routines

Conceptually, the process of making decisions concerning resource development in ISAAC is straightforward. The objective of the model's system expansion logic is to make decisions as consistently as possible with the resource strategy. As just discussed, the option and build levels are two components of a resource strategy. The other elements include a priority order for resource development, a set of constraints on resource availability and, potentially, a set of forced decisions to be made regardless of need. Note that the conservation programs and generating resources are freely mixed in the resource priority order.

The priority order can be defined as either static or dynamic. If static, it is specified by the user and will not change during the course of a study. In these types of studies, the Council generally develops a priority order by first screening resources based on levelized costs. It is then possible to make multiple trials of priority orders using ISAAC to capture the system-cost impacts of unit size, lead time, seasonal shape, secondary energy markets, integration into the existing system and uncertain variables.

Under the dynamic priority order option, internal forecasts of economics for discretionary conservation programs and generating resources are used to continually adjust the priority order as the model moves through the study period. At the beginning of each year, conditional forecasts of fuel prices and capital costs are used in conjunction with other static resource data to estimate the levelized cost of resources for the nearest possible in-service date to the current time period. These levelized costs are then modified with user-defined adjustments to account for persistent economic biases that are invisible to levelized cost calculations (e.g., seasonality). The resources are sorted by the adjusted levelized cost to produce a new priority order that is then used in the system expansion decision-making.

Resource decisions are made by stacking the remaining energy available from conservation programs and generating resources under the build and option requirements in accordance with the priority order. Forced decisions specified by the user are made regardless of need as are acquisitions of non-discretionary conservation programs. For discretionary decisions, recognition is made of lead times and development rate constraints. If energy from a resource is needed at a point in time that is equal to or less than its lead time, an action is taken on the resource. If the resource is expected to be needed at a point beyond its lead time, the action is deferred. Build decisions on generating resources consider only the construction lead time and can only be made on generating resources that have completed pre-construction activities and are currently in the option inventory. Option decisions consider the total generating resource lead time. Conservation programs use a user-defined scheduling window to determine program management actions.

There can be occurrences where the current resource priority order is not followed explicitly. Constrained development rates can cause parallel development of many resources. The model's highest priority is to maintain the reliability targets specified. Events, such as sudden spurts in load growth, may require scheduling resources with lower priority, but shorter lead time, in order to maintain balance with respect to the option and build levels specified. It is also possible that reductions in observed load growth may cause options to expire before they can be used and may lead to choosing resources out of order.

Conservation Program Modeling

The conservation modeling capability within ISAAC is extensive. A program is described through specifying a number of physical, economic and program management characteristics. Supply curves are defined through specifying program units available as a function of time and load level, in combination with values for savings per unit. As many different conservation programs as needed can be specified.

Conservation program types in ISAAC fall into four general categories. The first type, typically referred to as a non-discretionary program, will have units automatically secured regardless of need for the program's energy. This is exemplified by programs that would be implemented by building codes, such as the residential model conservation standards or new appliance efficiency standards. The units for this program type represent new purchases (e.g., new refrigerators purchased). Use of this program type forces acquisition of all new units and avoids the creation of lost opportunities. If the savings are not secured at the point of purchase, the opportunity will not arise again until the end of the lifetime of the newly purchased, less-efficient unit. The number of units acquired for a non-discretionary program will usually be linked to the observed load path. The higher levels of economic activity associated with the higher load growth paths will provide more conservation savings potential than at lower paths.

The second program type is similar to the first in that the units for potential acquisition represent new purchases. However, this is a discretionary program. That is, the units are not automatically acquired, but are secured through program management decisions. If the energy savings for a type-two program are not needed, they probably will not be acquired. Use of this program could simulate the creation of lost-opportunity resources.

The third program type is a discretionary program used to acquire savings from existing end uses. An example of this type would be existing residential weatherization. The principal difference between this program type and the previous one is that it is assumed lack of action does not create lost opportunities for conservation acquisition. If a house is not weatherized this year, it is still likely to be available for weatherization next year.

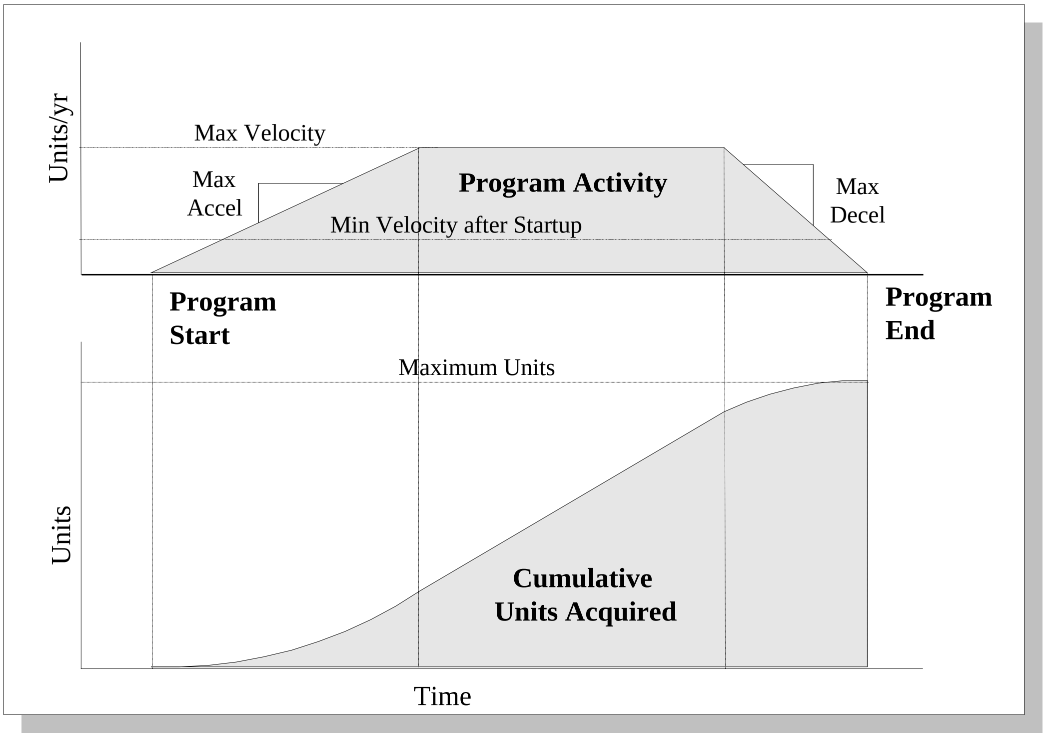
The fourth program type available is a two-stage program and is really a combination of the first and third program types. The first stage is designed to capture the effect of customer actions in a particular sector due to price response in the absence of an active program. When it is determined that the system needs energy from this program, it transitions to an actively managed discretionary program, and program management actions are taken to secure the remaining energy.

ISAAC also has a special category of programs for treatment of fuel switching, which allows for the economic and enviromental comparison of meeting demand through direct use of natural gas as opposed to construction of new electrical gas-fired generation.

Conservation has historically been thought of as a very flexible, short-lead-time resource. The perception has been that it comes in small amounts and its acquisition could be easily managed to adapt to changing load growth patterns. The experience of the 1980s has shown that, while conservation is an attractive resource, there are limits to its flexibility. This can be caused by any number of factors, but is due primarily to the time it takes to develop conservation delivery mechanisms and to the resistance encountered when changing program design characteristics or utility funding levels.

As discussed earlier, flexibility can affect system economics and cost-effectiveness. The flexibility of discretionary conservation in ISAAC is controlled through a set of program management parameters referred to as acceleration and velocity constraints. These are user-defined and specified separately for each discretionary program. These parameters are used to define upper and lower limits for the program activity levels and how quickly they can be changed. They are somewhat analogous to lead times for generating resources. These acceleration and velocity parameters are shown graphically in Figure H-7. They allow program development to be modeled much as the movement of a car would be, with the activity level of a program analogous to the velocity of the car. Each program has an upper limit to its activity level (maximum velocity) and constraints on how quickly the activity level can change (maximum acceleration and deceleration). A minimum activity level (minimum velocity) required to keep the program viable also is specified. High accelerations and velocities would mean a program is quite flexible and energy could be acquired quickly. Low values would indicate slow acquisition rates and difficulty in changing program activity levels. The modeling of these program constraints provides the ability to value the flexibility or constraints of conservation program development in assessing its cost-effectiveness.

Figure H-7
Conservation Constraints

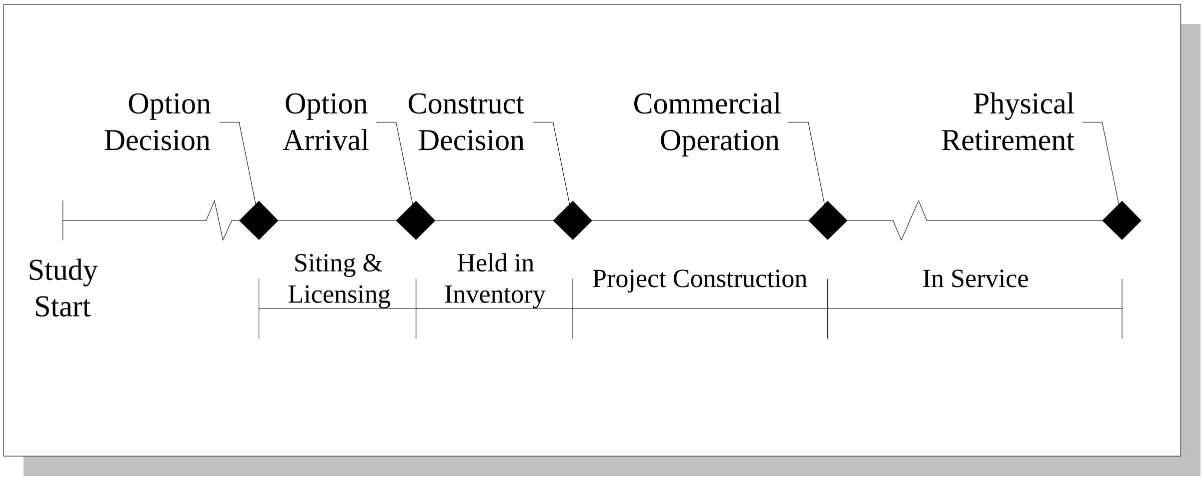


Generating Resource Modeling

Like conservation programs, new generating resources are described through a number of physical and economic characteristics. Large thermal resources can be modeled individually, while others typically have some amount of aggregation for computational efficiency. For instance, dispersed resources, such as small hydro and cogeneration, are typically aggregated into several generic blocks, and the input parameters describe the average values for the entire block. Supply curves for generating resources are defined by specifying the number of individual units available as a function of both time and load level. If there is more potential available for a resource under high load conditions, or if a user wanted to constrain the resource strategy to acquire a resource only under certain load conditions, these constraints can be modeled. While the supply curves for generating resources generally have some level of aggregation, the resource decisions are made on an individual unit basis.

Decisions are made in two steps for all generating resources. The first is a decision to option or start pre-construction activities on a unit; that is, to enter the siting, licensing and design stage. The second decision is to move a unit into the actual construction phase. Once an option decision on a unit is made, the resource moves into a period of pre-construction activity. If the unit successfully completes this stage, it moves into the option inventory. Once an optioned unit is in inventory, it becomes available for a decision to move it into the actual construction phase. Depending on need, it may be held in inventory for several years. Each generating resource has a user-defined inventory shelf life, and if a unit is not built before the end of its shelf life, it either expires and is no longer available as a regional resource, or again becomes a candidate to enter the siting, licensing and design stage. Once a build decision has been made on a generating resource unit, it moves through the construction phase and enters commercial operation where it will be available for dispatch through the end of its physical life. The process is summarized in Figure H-8.

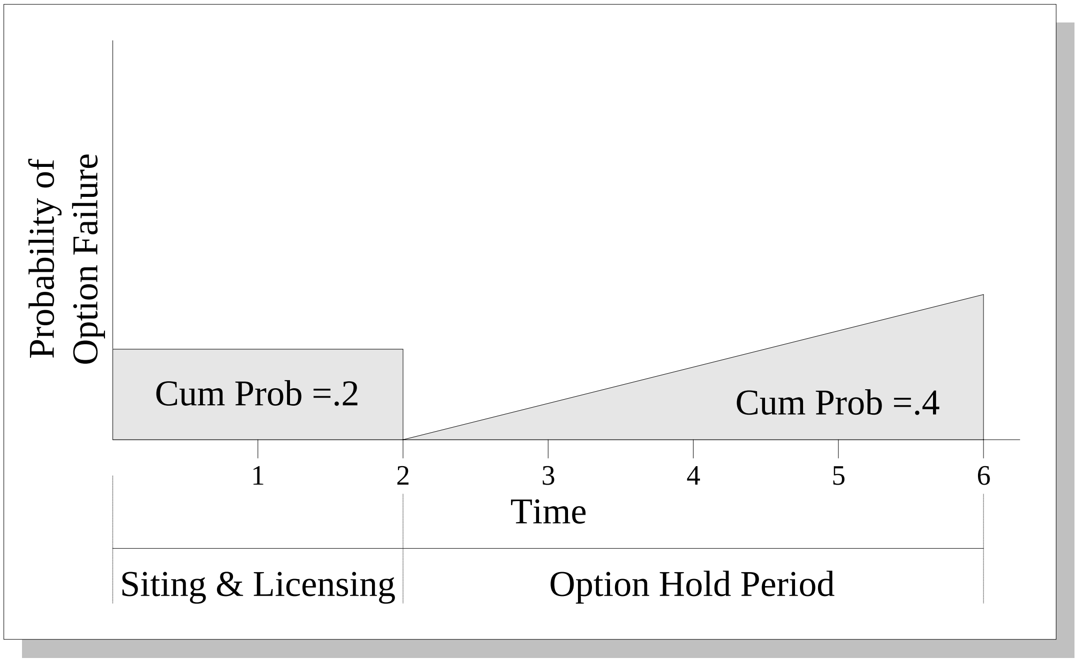
Figure H-8
Generating Resource Milestones



The timing of generating resource decisions is driven by the option and construction lead times for a resource. Unless forced resource decisions are specified by the user, decisions are delayed for as long as is possible while still meeting the option- and build-level targets. The user also can specify constraints on the number of units for which option or construction decisions can be made in any given year.

Another of the random variables modeled in ISAAC is the uncertainty associated with the successful completion of the pre-construction phase for a resource, and, if successful, whether it will remain a viable option over the maximum time it can be held in inventory. The user specifies values for the probability that an option will fail during the siting, licensing and design stage, and for the chance of an option failing over the period it is held in inventory. These input values are used to define the probability density functions for option failure during both the option and hold period. These are shown in Figure H-9. The option failure distribution is treated as uniform over the option period; that is, if the attempt to gain the option fails, it has an equally likely chance of failing at any point during the pre-construction period. If the option is successful and moves into inventory, the probability of failure starts at zero and increases linearly to the end of the option's shelf life. This represents a condition where the longer an option is held on the shelf, the higher the probability is that it will be lost before a decision is made to construct. The model takes random samples from these distributions, first to determine if and when the option fails during the pre-construction period. If the unit successfully completes this phase, a sample is taken from the hold period density function to determine if and when it fails during its stay in inventory. As option failures happen, information on the occurrence flows into the decision-making routines so corrective actions can be taken.

Figure H-9
Potential Option Failures



If a generating resource unit makes it all the way through the option or pre-construction stage and is moved into construction before an option failure occurs, it moves into commercial operation at the end of its construction period with certainty. In ISAAC, all of the uncertainty regarding the completion of a generating unit is resolved in the siting, licensing and design stage and during the period it is in inventory. Once a resource has negotiated the hurdles required to move into construction, it is assumed that it can be completed successfully.

Resource Supply Uncertainty

One thing many conservation programs and generating resources have in common is uncertainty about future supply. While the Council believes that its data development process produces reasonable and balanced supply estimates, there is no question that today's forecasts of cost and availability for future resource alternatives are highly uncertain. This is especially true of emerging technologies, such as solar photovoltaics, or of resources, such as geothermal, where the ultimate cost-effective energy potential depends on the future confirmation of the size and quality of an uncertain heat source.

ISAAC has algorithms that allow for the modeling of uncertainty in future resource supply and the examination of its impact on today's resource decisions. The methodology used to treat supply uncertainty is illustrated in Figures H-10 and H-11. Expected resource supply estimates and the long-term coefficient of variation for the supply distribution are added by the user. The expected supply can be a function of time and load. The supply distribution is assumed to be normally distributed. At the beginning of a pass through the study period, a random sample is taken from the supply distribution. This defines the amount of resource supply that will be observed to be available at the end of the planning period. The percentage difference between the mean and the observed supply is applied uniformly across the planning period to generate the observed supply through time.

As shown in Figure H-10, planning information for resource decision-making at the start of the study period is based on the mean value for resource supply. This represents the current supply forecast, even though it is in error. Resource decisions are made on the basis of the forecasted supply. If a supply forecast is too high, the resource may be counted on for more energy than it ultimately can supply. If the forecast for an inexpensive resource is too low, some cost-effective opportunities may be missed. As the model moves through the study period, the forecasts for resource supply are gradually adjusted to be consistent with the observed supply, simulating the process of learning more about the "true'' resource potential. The resolution of this uncertainty is proportional to elapsed time, and the updated forecasts as seen from several points in time are shown in Figure H-11. Any options on generating resources that would exceed the observed supply are forced to fail in the option failure process discussed previously. Observed conservation units are limited to the observed supply, even though program targets may exceed it. The impact of errors that are made because of inaccurate supply forecasts are captured in the simulation and can help identify the risks associated with overdependence or underdependence on uncertain resources.

Figure H-10
Resource Supply Uncertainty

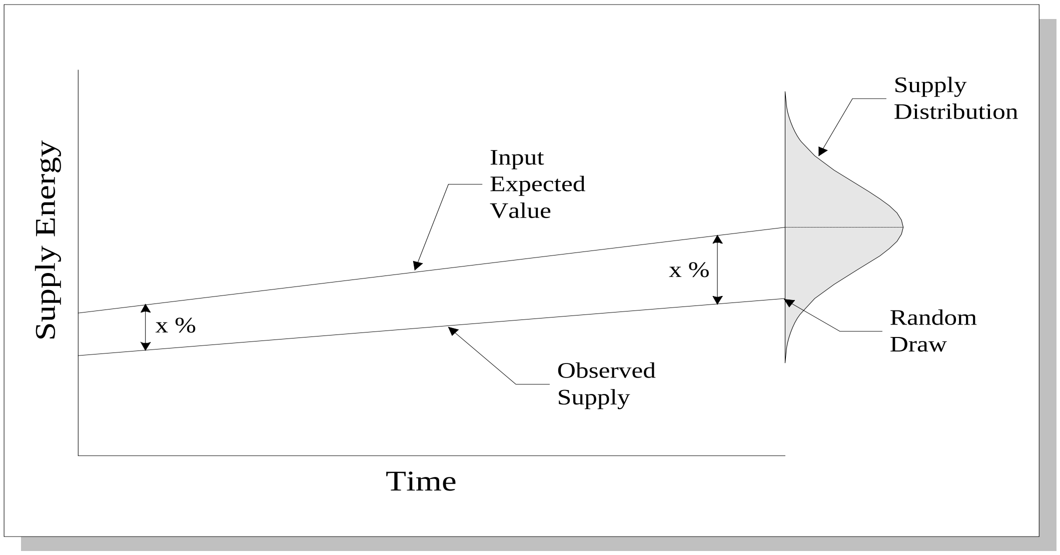
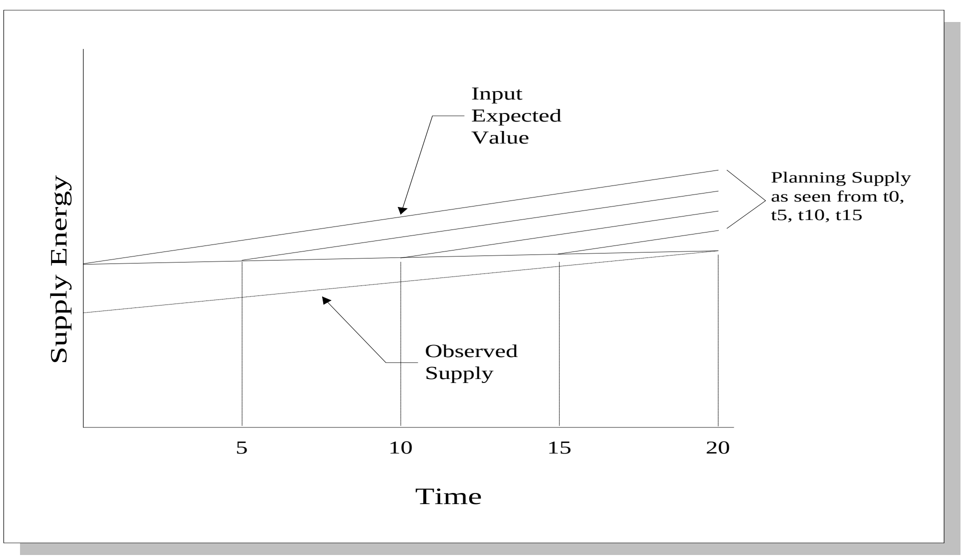


Figure H-11
Resource Supply Forecasts

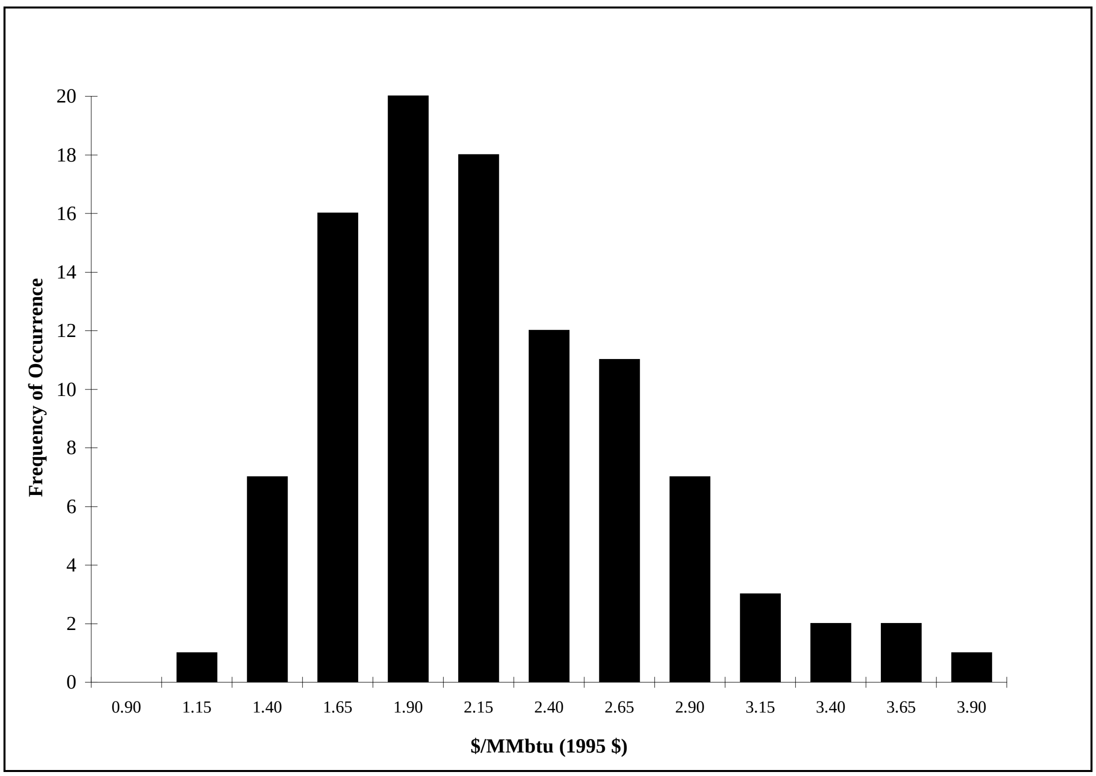


Fuel Price Uncertainty

An additional uncertainty treated in ISAAC is that associated with long-term fuel prices for generating resources. This effect is especially important to capture for potentially high variable-cost resources such as combustion turbines, gas-fired cogeneration, or rail-haul coal plants. Uncertainty in fuel prices can add significantly to the risk carried by the region, if substantial new commitments are made to these resources.

The algorithm for treatment of fuel price uncertainty is similar to that used for long-term load uncertainty. The inputs for fuel price include an initial price in some reference year and an annual stream of real escalation rates. These are used to develop a time series for fuel prices, which serves as the expected value of price through time. Additionally, a coefficient of variation is specified, which is used to generate a distribution for fuel prices at the end of the planning horizon. At the user's option, the distribution type is either normal or log-normal. At the beginning of a load path, a sample is taken from this distribution. This defines the ending fuel price for this pass through the future. The ratio of observed to expected price is used to develop a long-term trend fuel price pattern. The trend growth rates are then modified with a series of random shocks to introduce volatility into the fuel price path. The parameters influencing the amount of volatility produced are controllable by the user. A histogram for observed natural gas prices in 2015 for a 100s game for is shown in Figure H-12.

Figure H-12
Observed Natural Gas Prices in 2015 for Plan Studies



ISAAC has inputs for both variable-fuel and fixed-fuel price components for all generating resources, and fuel price uncertainty affects both components. It can be applied to any subset of both new and existing resources. Additionally, it is possible to model correlated fuel price groups. For example, if gas prices for combustion turbines are significantly higher than expected, prices for gas-fired cogeneration can be specified to show this same general pattern of escalation. Finally, because of the importance of the out-of-region bulk power market, dynamic adjustments based on variation in natural gas prices can be made to the price structure of the market.

System Operation and Production Costing

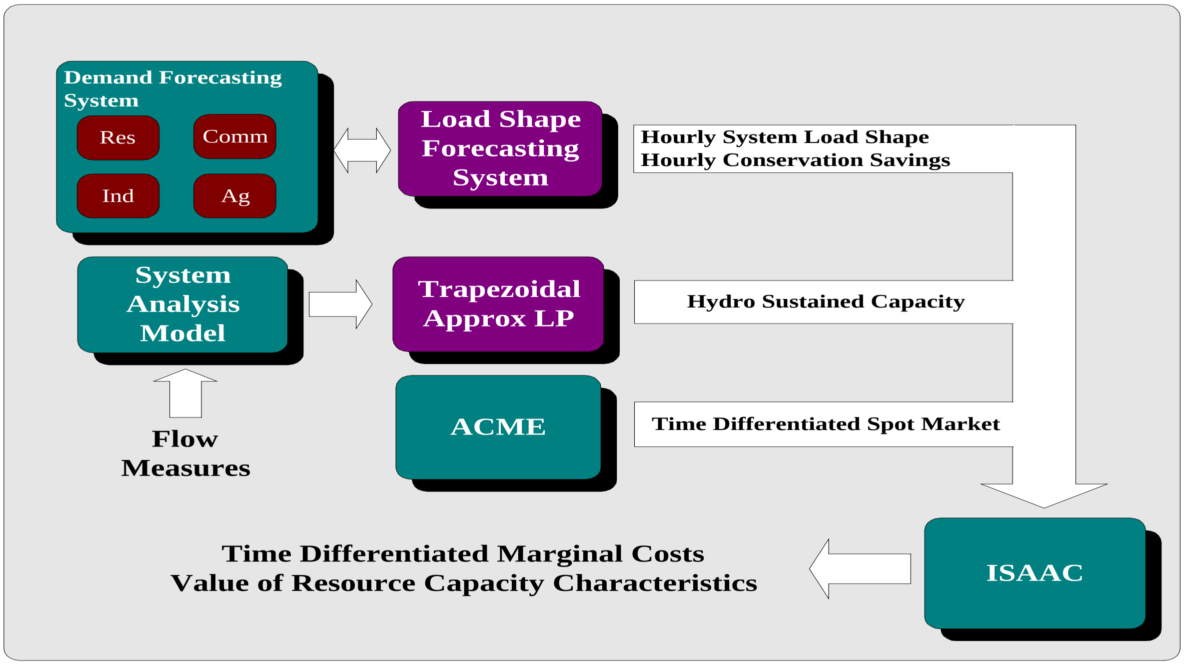
The regional power system has changed significantly since the 1991 Power Plan. One change that has a great effect on the technical aspects of resource evaluation is the changing operation of the regional hydroelectric system to aid endangered salmon runs. The significant loss of operational flexibility for the hydroelectric system results in no assurance that a given amount of average annual energy capability can meet monthly or weekly electricity requirements under all expected conditions. To address this issue, the Council has upgraded its analytical system to accommodate electrical capacity issues. A shorter time dimension has been added to the Council's analytical tools, including ISAAC.

The regional capacity issue addressed here is not peak hour capacity, as typifies most power systems. The regional power system has sufficient instantaneous peaking capability. However, when high daytime loads have to be met over an extended period, typically a week, the limited storage capability on the Lower Snake and some of the Lower Columbia projects can combine with low natural stream flow to constrain generation. This is typically referred to as a sustained peaking constraint. For this power plan, ISAAC has been restructured to incorporate the effect of hydro sustained peaking limitations on regional production costs.

The amount of data needed to treat capacity in the Pacific Northwest is voluminous, and in order to maintain ISAAC's computational efficiency, the process to incorporate capacity relies on information produced by other models. Figure H-13 shows the process the used by the Council in this plan. Hourly load shape information is produced by the Council's Load Shape Forecasting System (LSFS). The LSFS is documented in Appendix D. It works in combination with the demand forecasting system to produce hourly data for load shape and conservation program savings. Estimates of the sustained peaking capability of the hydro system are produced by processing the results of a detailed hydroregulator, in this case the System Analysis Model, with a linear programming algorithm that estimates the ability of the hydropower system to generate during peak periods. It also produces estimates of the off-peak minimum generating constraints. This algorithm, referred to as the Trapezoidal Approximation, is documented in Appendix H2. Finally, data on the time-differentiated nature of the out-of-region bulk power market, is produced using the Accelerated California Market Estimator (ACME). See Appendix E for a description of this analysis.

Figure H-13

Capacity Information Flow



While the LSFS produces 8,760 hourly loads for each year, the information is used in ISAAC in an aggregated form. The hourly data from the LSFS is used to produce a typical week load shape for all months of the year. The 168 hours in a week are then aggregated further into specific time periods of interest for use in the dispatch routines. These time periods are user-defined, but for this plan the Council used the following definition:

- Load Segment 1: Weekdays 8AM to 6 PM (50 Hr).
- Load Segment 2: Weekdays 4AM to 8AM and 6PM to 10PM; Weekends 4AM to 10PM (76 Hr).
- Load Segment 3: Weekdays 10PM to 4AM (30 Hr).
- Load Segment 4: Weekends 10PM to 4AM (12 Hr).

In this plan, Load Segment 1 represents the “on-peak” period and is used to capture the effect of a 50-hour sustained peaking constraint. Load Segment 4 represents “off-peak” weekend periods and is modeled separately to reflect the impact of minimum generation constraints. The chronological mapping is illustrated in Figure H-14. The values from each of these time periods are averaged to produce a block load duration curve which is used in the hydro-thermal dispatch routines. (Figure H-15).

Figure H-14

Mapping of Typical Week Demand to Load Segments

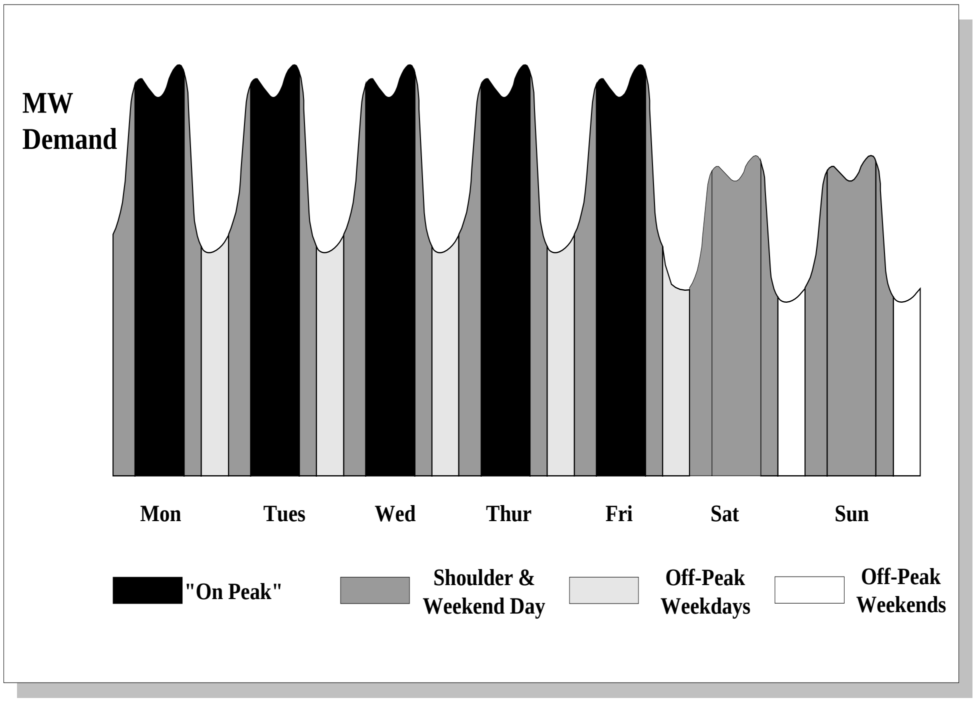
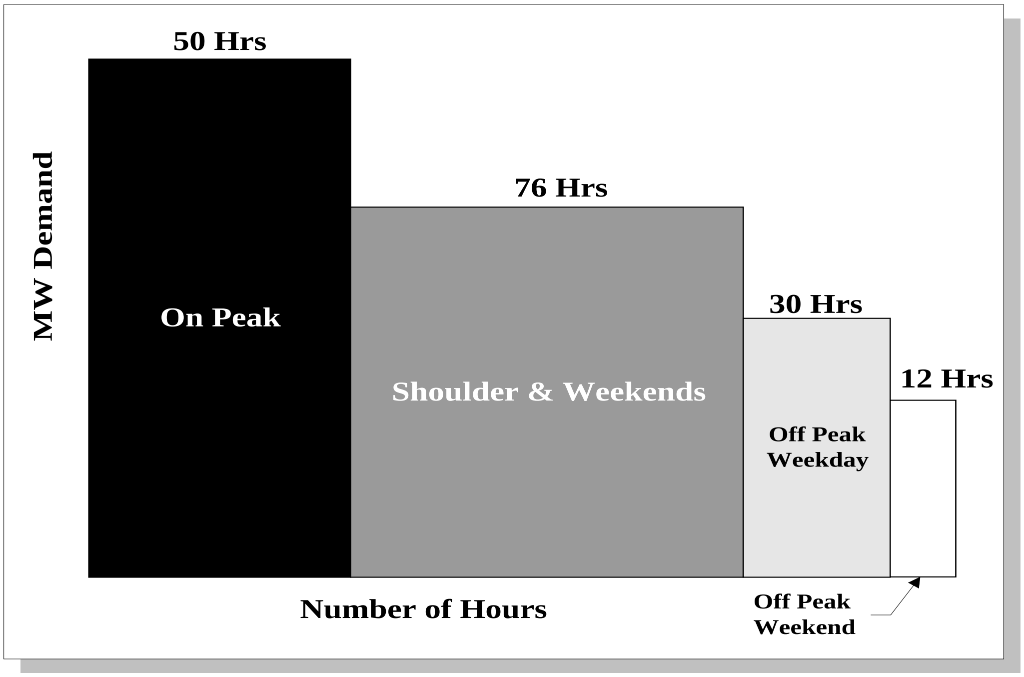

MW
Demand
Mon
Tues
Wed
Thur
Fri
Sat
Sun
"On Peak"
Shoulder &
Weekend Day
Off-Peak
Weekdays
Off-Peak
Weekends

Figure H-15
Block Load Duration Curve used in Dispatch



The hydro-thermal dispatch in ISAAC is the area that has undergone the most significant revision since the 1991 Power Plan. Previous versions of ISAAC used an "energy only" dispatch. An explicit assumption was made that if the system could produce enough energy to meet the load for a month, that the output could be shaped to meet whatever daily load patterns occurred. This version of ISAAC has been retooled to address diurnal operating constraints. The primary objective for the revisions is to reflect the value of capacity characteristics of resources in the cost-effectiveness evaluation. For example, it is now possible to differentiate the economic value of a conservation program that produces the majority of savings in peak periods from a program with the same savings but in a flat profile.

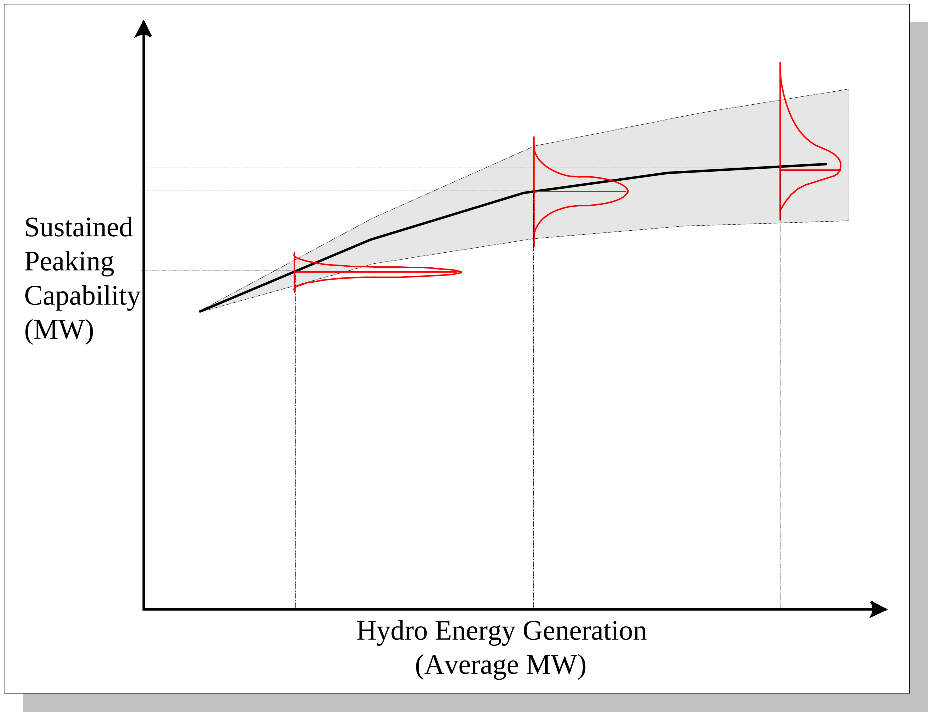
This new ISAAC hydro-thermal dispatch module is quite complex, and the algorithm is described in detail in Appendix H1. However some of the major features include:

- A modified Booth-Baleriaux hydro-thermal dispatch with treatment of thermal forced outage, multiple states for hydro capacity, and representation of energy limited units.
- A representation of the future value associated with discretionary use of hydro-storage and evaluation of the tradeoffs between using storage for generation in a current period versus future time periods.
- A one-dam composite model of the Northwest hydrosystem, with capacity and energy constraints driven through the results of detailed hydroregulation studies.
- Time of day differentiation for the price and size of out-of-region bulk power markets.
- Treatment for pumped storage projects.
- User-defined precision for aggregation of time periods within a typical week,
- Time-differentiated Northwest marginal operating costs.
- User-defined configuration for aggregation of Northwest thermal units.

As noted above, ISAAC uses a one-dam model for the Northwest hydrosystem. This is again for the purpose of improving computational speed. Constraints on hydro operation are based on the results of studies performed with detailed seasonal hydro-regulation models, such as the System Analysis Model. The energy constraints are specified as composite system energy values in units of megawatt-months, and vary by month and water condition. They include rights to firm hydro energy, flood control levels, inflows to the system, and the aggregate generation and spill requirements associated with fish flow measures. To capture the impact of streamflow variability, the model randomly chooses water conditions based on probabilities associated with the 102-year water record.

A necessary, but non-trivial component of the capacity analysis is the estimation of the capability of the hydrosystem to generate during peak periods. This is a complex problem that is driven by a number of parameters, including project storage levels and associated head, project physical constraints, project releases, travel time between projects, the size and location of natural inflows to the system, and turbine-generator forced outages. As noted previously, the Council uses a linear programming model referred to as the Trapezoidal Approximation for estimation of hydropower sustained peaking capability. The algorithm is described in detail in Appendix H2. The Trapezoidal Approximation requires project-specific information, and because ISAAC uses a composite model of the hydrosystem, it's not feasible to place the algorithm directly into ISAAC. Instead, the Trapezoidal Approximation is run against a set of detailed hydroregulator model outputs for a given fish flow regime. This is typically done across the 50-year water record and for differing turbine forced outage conditions and maintenance conditions. The results are synthesized into inputs representing the sustained peaking capability of the system as a function of monthly energy generated. This function is then used in the dispatch to correlate available capacity with the amount of hydropower energy used in the time period. The concept is illustrated in Figure H-16. It shows that at given energy output, there can be significant uncertainty in sustained peaking ability, depending on observed values for the parameters listed above. This probability distribution is used to represent the different possible states for hydrocapacity at a given hydropower energy generation level, and is used in the energy-constrained Booth-Baleriaux dispatch in a fashion similar to that for thermal units.

Figure H-16
Stochastic Treatment of Sustained Peaking Capability



Financial Analysis

Financial modeling in ISAAC is performed through a two-step process. At the beginning of a study, a submodel referred to as Microfin performs detailed calculations for capital revenue requirements for each possible resource and sponsor combination. These are translated into a set of factors expressing yearly real capital revenue requirements as a proportion of the cost of the resource and are stored for later use. Then in the simulation, whenever a resource is developed by a sponsor, the appropriate set of factors is used to estimate the stream of nominal capital revenue requirements for that resource.

Microfin treats both conservation programs and generating resources. Annual revenue requirements can be made up of a number of cost components. These include return on debt, return on equity, depreciation, state and federal taxes, deferred state and federal taxes, insurance, property tax and gross revenue tax. Direct capital expenditures for a resource are spread over the construction period according to user-defined cash flow distributions. User options allow the selection of rate-base inclusion of construction work in progress, or to accumulate an allowance for funds used during construction, with no return allowed on either the direct or indirect investment until the resource is placed in service. A further option to simulate Bonneville financing through Treasury borrowing also is allowed. In addition, provisions are made to accommodate the Bonneville acquisition of resources that would be developed by a party placing requirements contracts on Bonneville or by an independent power producer.

Only the capital expenditures associated with construction of a resource are financed. Generating resource option costs are expensed uniformly over the pre-construction period. If a resource fails during the option process, its option expenses are prorated according to how far it had gone through the process before it failed. Costs required to maintain an option on a resource while it is held in the option inventory are expensed, as are the administrative costs associated with conservation programs. For conservation programs, user-defined incentive levels are used to control how much of the conservation investment is funded by utilities and how much by consumers. The financial parameters and accounting methods for utilities and consumers can be defined separately.

Rates and Price Effects

Price elasticity of demand can have an effect on the cost-effectiveness and need for resources, and is treated in the model. The detailed demand forecasts that are inputs to ISAAC are developed through detailed end-use and econometric models. These forecasting models calculate changes in price and the resulting response in loads. That is, price effects already have been accounted for at the price levels underlying the detailed forecasts. In ISAAC, further adjustments to demand due to price only are required if the resource strategy produces prices that are inconsistent with those underlying the detailed forecasts. To allow the model to track these differences, a reference price structure is entered, which defines the level of prices associated with the detailed forecasting models as a function of load path. As a random load path within ISAAC unfolds, this reference-price/reference-load structure is used to discern whether the observed prices are consistent with the reference prices associated with the detailed forecasts. If they are consistent, no further adjustment due to price effects is required. If loads and prices are determined to be out of equilibrium, appropriate adjustments to load are made.

Terminal Effects

Terminal effects in power planning models arise from the fact that the planning horizons typically used are limited (e.g. 20 years), and that resource physical lives can be long with respect to planning horizons. (e.g. 20-50 years for generating resources and up to 70 years for some conservation measures.) Long lived resources or resources put in place near the end of the planning horizon may have most of their cost impact beyond the planning horizon. A method that simply truncates the cost accounting at the end of the planning horizon can miss significant portions of committed resource costs. Also, because resource planning studies are typically comparative in nature, it's important that the cost of the same "product" in two alternative studies be compared. It would be inappropriate to compare the direct costs of a study which had new resources producing energy through 2020, to another study with alternative resources producing energy through 2030.

A straight financial "salvage value" approach to the problem is usually inadequate, because the issue is not just one of the recovery pattern for capital investment, but also of impact on production costs. For example, the capital for a combined cycle turbine is small compared to its operating cost, and the only way it's operating cost can be estimated very well is to simulate its operation in the power system.

The only approach to terminal effects the Council has found minimally satisfactory is one in which all the costs of a resource decision are counted, including its cost of replacement. In this plan, resources are assumed to be replaced in kind to perpetuity. This is different than previous versions of the plan that typically used a generic replacement resource for retirements outside of the 20 year planning horizon. The generic replacement resource approach is not used here because it was found that the results of some studies could be quite sensitive to the cost of this generic resource, and it's clear that estimation of resource costs 30 years from now is speculation at best.

The terminal effects methodology currently used in ISAAC works as described below. The first two steps deal with capital effects and the third addresses production costs.

1. At the end of each pass through the study period, any capital recovery remaining for generating resources and conservation programs developed under that load path is simulated and costed out. In other words, the full recovery of the unamortized investment is included in terminal costs, regardless of when they occur.
2. The retirement schedule for all generating resources and conservation programs developed for the game is determined and all resources are simulated as replaced in kind at retirement. The present

value of the capital revenue requirement associated with each replacement is translated into an annuity over the physical life of the resource. This annuity is used to calculate the present value of the capital cost for replacement to perpetuity.

3. For production costs in the terminal horizon, the regional demand and system resource configuration occurring in the last study year are assumed to be extended indefinitely. This is consistent with the capital replacement methodology in steps one and two. Because flow conditions can have a large effect on regional production costs, the net system production costs for these loads and resources are simulated for one year for each of a user-defined set of water conditions. The Council uses three water years, corresponding to poor, moderate, and high runoff years. The net production costs are averaged, and as in step 2, treated as a perpetual annuity that is translated into a present value.

The net present value of these terminal horizon costs is kept separate from the detailed accounting during the study period, but are generally included when comparing the economic results of two studies. The degree to which these costs affect present values and comparative study results is largely a function of the real discount rate used in the studies.

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APPENDIX H1

ISAAC CAPACITY DISPATCH DOCUMENTATION

INTRODUCTION

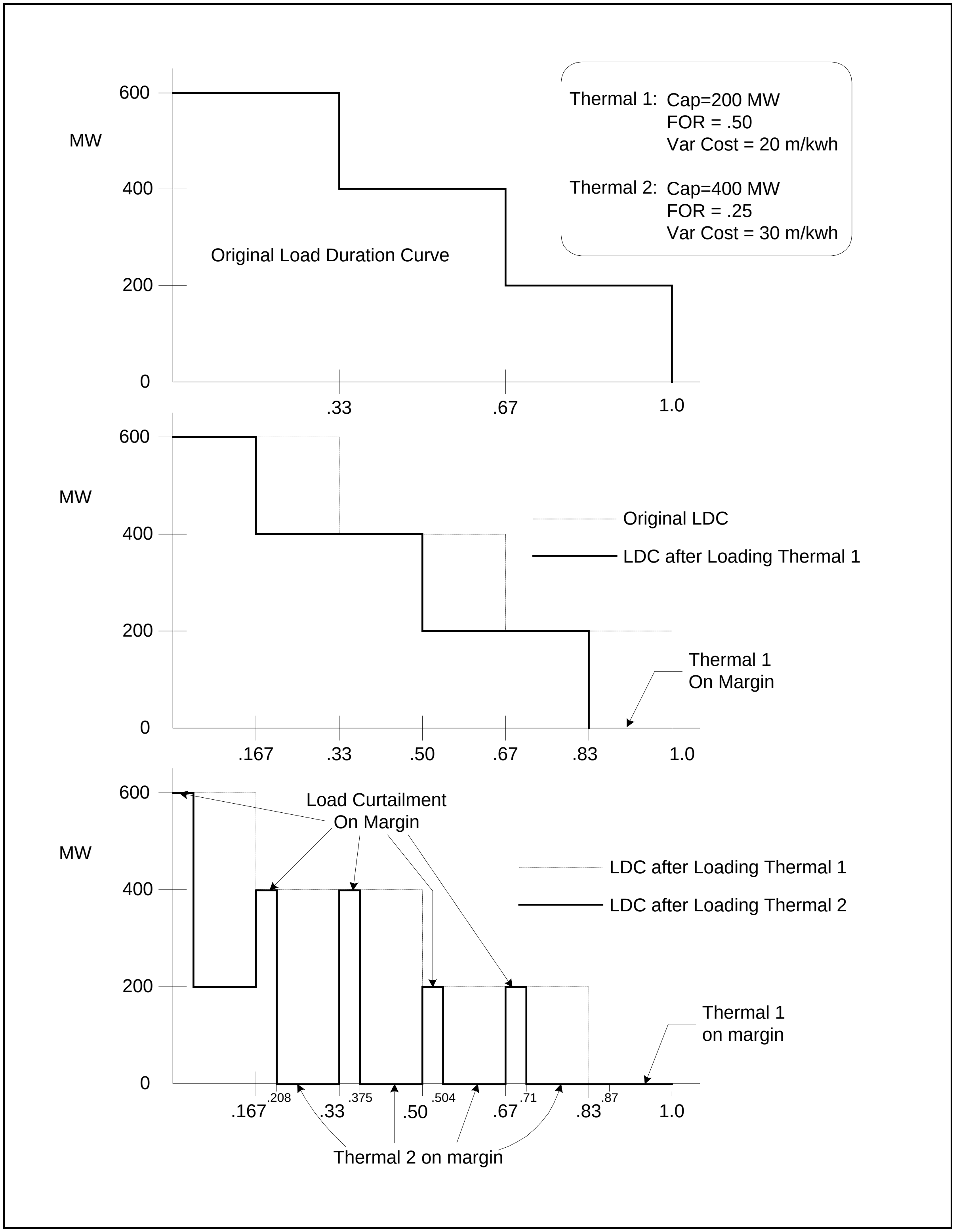
This report is submitted to the Pacific Northwest Electric Power and Conservation Council (NWPPC) as part of contract C93-009, ISAAC Capacity Modeling Enhancement, in order to satisfy the fourth deliverable under the statement of work. There are two separate reports to satisfy this fourth deliverable. One covers the documentation on the Trapezoid Approximation, while this report discusses the implementation of capacity constraints in the system dispatch of the ISAAC model. ISAAC's dispatch now consists of a Booth-Baleriaux (B-B) algorithm combined with a linear program (LP) solved via Dantzig-Wolfe (D-W) decomposition. This report provides a general discussion of what the dispatch is doing, two simple examples of how the dispatch works, and a mathematical discussion of the theory behind the B-B dispatch with PSRI's modifications to the traditional B-B dispatch to account for hydropower energy limits.

OVERVIEW OF DISPATCH

The B-B algorithm is widely used for production costing by electric systems consisting mostly of thermal plants. It uses information on the forced outage rates of thermal plants, the capacity of thermal plants, the variable cost of thermal plants, and an hourly load duration curve in order to "load" the thermal plants under the load duration curve in economic order. The B-B algorithm determines a plant's generation by developing an economic loading order and then, for each plant, calculating the amount of remaining load not served before and after loading the plant. The difference between the amounts of load not served is the amount of generation from the plant. As output the B-B dispatch gives production costs, loss of load probability, and marginal costs. One way the B-B algorithm has handled hydropower generation in the past is by specifying its capacity and a fixed amount of energy available from the hydropower. The downfall of this method is that the hydropower generation doesn't reflect the changing value of water as a function of the amount of water withdrawn from the system..

A visual representation of the B-B algorithm using only two thermal plants can be seen in Figure H1-1. The first graph is a simplified version of the hourly loads sorted from highest to lowest over a given time period, called a load duration curve (LDC). The second graph shows the original LDC and the remaining load not served after "loading" a thermal plant with a capacity of 200 megawatts and a forced outage rate of .5. The area between these two lines is the amount of generation obtained from thermal plant 1. It can also be seen from the graph how often thermal plant 1 is the marginal plant. A plant is the marginal plant when the loading of it causes the load not served to go to zero. The third graph shows the remaining load not served after the loading of thermal plant 1 and a second thermal plant with a capacity of 400 megawatts and a forced outage rate of .25. Again, the area between the two lines is the amount of generation from thermal plant 2, and the portions of the curve where thermal plant 2 takes the load not served to zero are the times when it is on the margin. The times when there is still load not served is when load curtailment is on the margin, and summing the probabilities associated with load curtailiment gives the loss of load probability.

Figure H1-1
Example Load Duration Curves

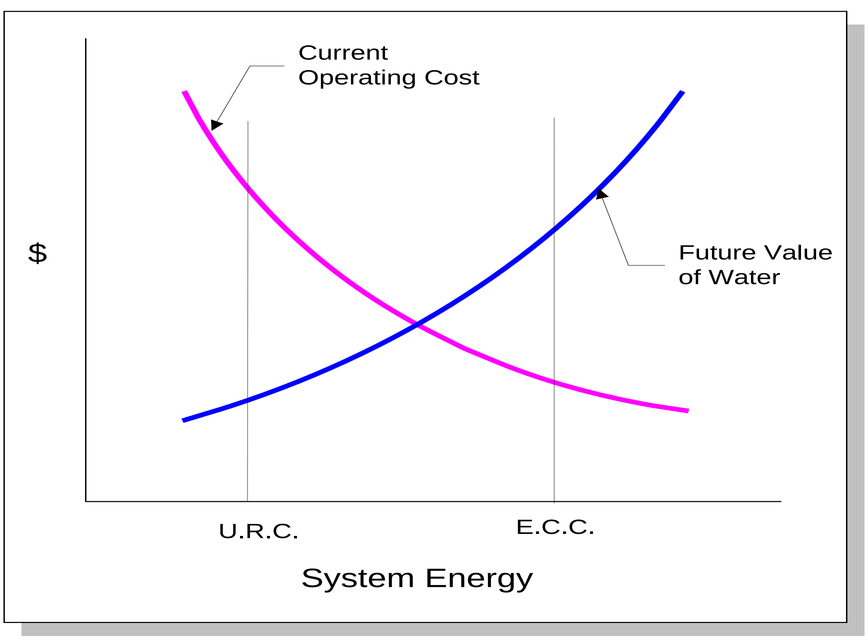


As you can see, the B-B algorithm is simple, but powerful. However, until recently, the B-B algorithm has not been used by systems that are primarily hydropower. Because the above algorithm does not maintain chronological information, hydropower has been generally modeled as a limited amount of energy with a fixed capacity inserted under the LDC to levelize marginal costs. Thus there is no ability to use hydropower regulation models and represent all of the flexibility associated with hydropower capacity in energy generation, by using just a static value for a hydropower plant. But each of these historical limitations of the B-B algorithm have been overcome in our ISAAC implementation. ISAAC is a chronological simulation model with a one-dam hydropower regulation model within it. The B-B algorithm within ISAAC is used to model the dispatch for each month given the amount of hydropower energy available from the hydropower regulator and the future value of stored hydropower energy.

To understand the need for limiting the amount of energy from a hydropower plant, let's look at the Pacific Northwest hydropower system. The Pacific Northwest has over 30,000 MW of capacity available in any month, but in average water it has only about 16,000 average megawatts of energy available. Depending on the water year, water may not be available to generate the energy, even though the capacity from the hydropower plant is available on any hour. The traditional B-B algorithm easily handles the availability of the hydropower capacity on any hour, but cannot limit the total hydropower energy generated based on water availability. Advances with the B-B algorithm in modeling energy limited systems has made it possible to incorporate a reasonable representation for hydropower. This is done through finding a shadow cost or value for the hydropower, in order to determine where it will go in the loading order, while at the same time checking to see if the hydropower energy limitations are met. To find this shadow cost, the new B-B calculates the operating costs of the system for a period, assuming hydropower is dispatched at different points in the loading or dispatch order. By doing this, a cost versus hydropower generation curve can be drawn. The B-B algorithm can then compare this cost curve to the future value of water at different hydropower system drafts. The point at which the curves cross determines the amount of hydropower generated and the price at which it is to be dispatched (see Figure H1-2). This point is where total costs are minimized.

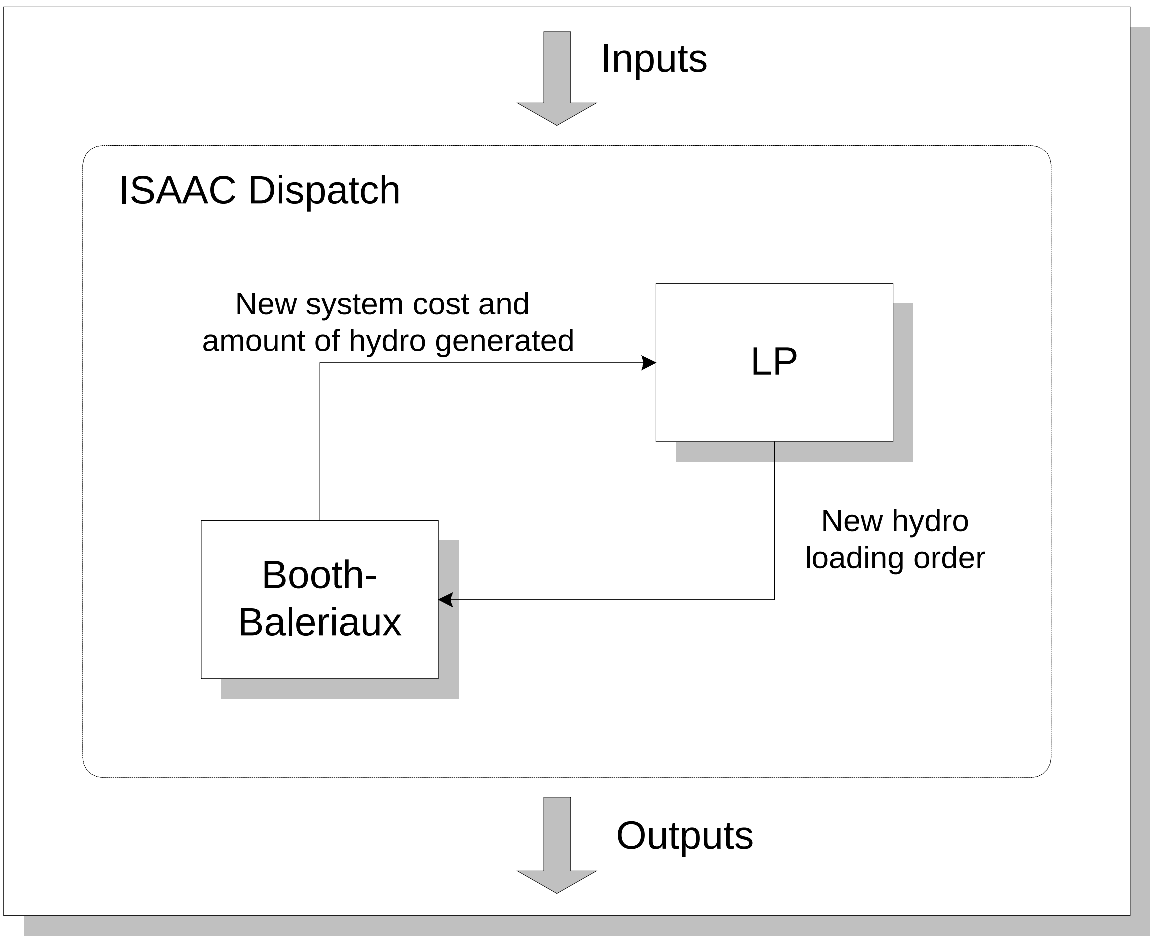
Figure H1-2

Tradeoff Between Current and Future Operating Costs



Currently, ISAAC has a one-dam hydropower model, but we have left the door open to be able to model multiple hydropower plants in the future by using an LP formulation and D-W decomposition to find the hydropower generation-versus-cost curve. With multiple energy-limited plants (including hydropower, some thermal, and pumped hydropower), finding the system operating costs with all the different plants dispatched in all the possible loading orders would take too long. Therefore, we only look at a subset of all the possible loading orders that, through an iterative process, then allows us to converge to the optimum solution. We do this through an LP formulation and D-W decomposition. Figure H1-3 shows the schematic of how the LP and the B-B dispatch interact. The process is iterative where the B-B dispatch assumes a shadow cost of hydropower and dispatches it accordingly and then feeds total (real) system costs and the amount of hydropower generation to the LP. The LP then checks whether the hydropower energy limit is met, comes up with a new estimate of the shadow cost of hydropower and feeds this to the B-B dispatch. This iterative process converges when the LP solution can not be improved (i.e. it has reached the optimum). Therefore, this dispatch algorithm recognizes the energy-limits of the hydropower system, while minimizing the total costs of meeting load.

Figure H1-3
Booth-Baleriaux, LP Interaction



EXPLANATORY EXAMPLES

To understand how the B-B dispatch works in ISAAC in detail, we will go through two examples. The first shows how the traditional B-B dispatch works and the second shows how the B-B dispatch with the LP and D-W decomposition works.

Example 1

In this example we will see how the B-B dispatch calculates the expected generation from each plant, the expected load curtailment, the probability of each plant and load curtailment being on the margin, the expected operating costs, and the marginal costs. The system consists of two thermal plants and no hydropower plants.

Load: 400 MW

Thermal 1: 1 unit
200 MW Capacity
10% FOR
$20/MWh

Thermal 2: 2 units
400 MW Capacity
15% FOR
$30/MWh

Load Curtailment Costs: $300/Mwh

Load curtailment can be thought of as a thermal plant with infinite capacity and a curtailment cost as the operating costs.

Hours in Period: 720 hours

First we calculate the probability distributions for each plant's generation.

Probability of Failed Units

Plant	0 Units	1 Unit	2 Units
Thermal 1	.9	.1	
Thermal 2	.7225	.255	.0225

Then we determine the economic loading order of the plants. Clearly, the economics determine that Thermal 1 is loaded first and the Thermal 2 units are loaded second.

The B-B dispatch algorithm calculates the expected generation of a particular plant as the difference between the expected load curtailment after loading all plants lower in the loading order and the expected load curtailment after loading this plant.

E_{lc} = Expected load curtailment before loading any plants = 400 MW

E_1 = Expected load curtailment after loading Thermal 1 = .9 * 200 MW + .1 * 400 MW

= 220 MW

Therefore, the expected generation of Thermal 1 = $E_{lc} - E_1$ = 180 MW

And the expected costs of running Thermal 1 = $2,592,000

E_2 = Expected load curtailment after loading Thermal 2 (on top of Thermal 1)

= .1 * .0225 * 400 MW + .1 * .255 * 200 MW + .1 * .7225 * 0 MW +

.9 * .0225 * 200 MW + .9 * .255 * 0 MW + .9 * .7225 * 0 MW

= 10.05 MW

Therefore, the expected generation of Thermal 2 = E_1 - E_2 = 209.95 MW

And the expected costs of running Thermal 2 = $4,534,920

Because we have no more plants, the expected load curtailment = 10.05 MW

To calculate the probability of each of the plants being the marginal plant, we look at scenarios where loading that plant brought the remaining load not served down to zero.

Probability of Thermal 1 being on the margin = 0

Probability of Thermal 2 being on the margin = .1 * .7225 + .9 * .255 + .9 * .7225

= .952

Probability of load curtailment being on the margin = .1 * .0225 + .1 * .255 + .9 * .0225

= .048

Therefore, the loss of load probability is .048.

To calculate marginal costs, we take the probability of a plant (including load curtailment) being on the margin times the cost of the plant.

Marginal Costs = 0 * $20/MWh + .952 * $30/MWh + .048 * $300/MWh = $42.96/MWh

Example 2:

In this example we will replace one of the thermal plants with a hydropower plant. Because hydropower has no immediate running costs, the problem arises as how to value hydropower in order to put it in the correct loading order and minimize costs. Hydropower also has the problem of having energy limits (namely, we run out of allocated water). We will use an LP formulation and Dantzig Wolfe decomposition in conjunction with the B-B dispatch to determine the loading order, the expected generation of the hydropower, and the value of the hydropower in this period. The B-B/LP is an iterative process and in this example will go through four iterations or steps before converging on the best solution. This means we will be doing the B-B dispatch four times and solving the LP three times. The probability of load curtailment and marginal costs will also be calculated as in Example 1.

Load:	400 MW		
Thermal 1:	1 unit	Hydro:	300 MW Capacity with .25 probability
	200 MW Capacity		250 MW Capacity with .75 probability
	10% FOR		Minimum energy = 0
	$20/MWh		Maximum energy = 220 ave. MW
			Future value of water = 0 $/MWh

Load Curtailment Costs: $300/MWh for first 100 MW

$400/MWh thereafter

Note that on an expected energy basis, the hydropower + thermal generation = load

STEP 1: First we will do a B-B dispatch ignoring the energy constraints on the hydropower. We will assume the hydropower has no costs or value, and we will load it first at a cost of zero and then Thermal 1 at 20 mills.

Probability of Available Capacity

Plant	Capacity	Probability
Thermal 1	200 MW	.9
	0 MW	.1
Hydro	300 MW	.25
	250 MW	.75

E_{lc} = Expected load curtailment before loading any plants = 400 MW

E_H = Expected load curtailment after loading Hydro = .25 * 100 MW + .75 * 150 MW

= 137.5 MW

Therefore, the expected generation of Hydro = E_{lc} - E_H = 262.5 MW

E_1 = Expected load curtailment after loading Thermal 1 (on top of Hydro)

= .25 * .9 * 0 MW + .25 * .1 * 100 MW + . 75 * .9 * 0 MW +.75 * .1* 150 MW

= 13.75 MW

Therefore, the expected generation of Thermal 1 = E_1 - E_H = 123.75 MW, the expected generation costs = $1,782,000, the expected load curtailment = 13.75 MW, and the total expected costs = $4,752,000 (or $6,600/hour).

The probability of the plants being on the margin is calculated as in Example 1. Namely, the probability of Hydropower being on the margin = 0, the probability of Thermal 1 being on the margin = .25 * .9 + .75 * .9 = .9, and the probability of load curtailment being on the margin = .25 * .1 + .75 * .1 = .1 Therefore, the loss of load probability is .1.

Because the maximum energy available from the hydropower system is 220 MW, the expected generation of the hydropower in this dispatch is not a feasible solution. Therefore, we will take the results of this dispatch and use it in the following LP (master problem for the Dantzig-Wolfe decomposition) to determine a better estimate of the value of hydropower.

Objective: minimize costs = $\sum_i$ (total costs in i^{th} dispatch * weight on i^{th} dispatch) + penalty for not staying within the hydropower maximum energy * amount by which not meeting hydropower maximum

Subject to: $\sum_i$ (hydropower generation in i^{th} dispatch * weight on i^{th} dispatch) - amount by which not meeting hydropower maximum $\leq$ maximum hydropower energy (1)

$\sum_i$ (weight on i^{th} dispatch) = 1

(2)

weights on i^{th} dispatch, amount by which not meeting hydro minimum $\geq$ 0

Because we have done only one dispatch, there will only be two variables in this first LP, the weight on the first dispatch results, and the amount by which we are not meeting the hydropower minimum. Obviously, this first LP can be solved by inspection. The weight on the first dispatch is 1 and the amount by which we are not meeting the hydropower minimum is 42.5. However, the real reason for solving this LP is to obtain a better estimate of the value of hydropower energy, namely the dual variable of the first constraint (1). Here is where the correct choice of the penalty for not meeting the hydropower minimum is important. By the nature of this first problem, whatever is specified as the penalty will end up as the value of hydropower. In the next iteration we want the hydropower not to be dispatched, therefore, we will choose a penalty that is larger than the cost of load curtailment (we choose 3000). Note also that the cost figures we will use in the LP are dollars per hour. This does not effect the final answer to the LP because the number of hours for the period is a constant, but it does make the hydropower shadow prices come out to be dollars per megawatt-hour.

The first LP then is :

$$\begin{aligned}
&\min z \\
&z = 6600 * \lambda_1 + 3000 * \delta \\
&s.t. \\
&262.5 * \lambda_1 - \delta \leq 220 \\
&\lambda_1 = 1 \\
&\lambda_1, \delta \geq 0
\end{aligned}$$

where: λ_1 = weight on first iteration of the B-B dispatch

δ = amount by which we are not meeting the hydropower maximum energy constraint

and the solution is: λ_1 = 1, δ = 42.5, π_1 = 3000, π_2 = -794,100,

z = 134,100

where: π_1 = the shadow price on the hydropower constraint

π_2 = the shadow price on the lambda constraint

STEP 2: Because the value of hydropower is now \$3,000/MWh, we will load Thermal 1 first, and not load the hydropower at all. Therefore,

E_{lc} = Expected load curtailment before loading any plants = 400 MW

E_1 = Expected load curtailment after loading Thermal 1

= .9 * 200 MW + .1 * 400 MW

= 220 MW

The expected generation of Thermal 1 = E_{lc} - E_1 = 180 MW, the expected generation costs = \$2,592,000 , the expected load curtailment = 220 MW, the expected load curtailment costs = (\$300/MWh*100MW + \$400/Mwh*120 MW)*720 hours = \$56,160,000 and the total expected costs = \$58,752,000 (or \$81,600/hour).

The probability of Hydropower being on the margin = 0, the probability of Thermal 1 being on the margin = 0, and the probability of load curtailment being on the margin = 1 Therefore, the loss of load probability is 1.

Now we test to see if the algorithm has converged. In the Dantzig-Wolfe decomposition algorithm, columns (i.e. variables) are added to the master problem until adding an additional column won't improve the solution (i.e. optimality has been reached). From LP theory, a column will improve the solution if the reduced costs for that column are negative. Therefore, the convergence test is:

If (total costs + hydropower shadow price * hydropower generation + shadow price on λ constraint) is zero or positive, the algorithm has converged.

Since 81,600 + 3000*0 - 794,100 is less than zero, the algorithm has not converged. Therefore, we will go back to the Dantzig-Wolfe master problem and add a variable.

The second LP then is :

$$
\begin{aligned}
&\min z \\
&z = 6600 * \lambda_1 + 81600 * \lambda_2 + 3000 * \delta \\
&s.t. \\
&262.5 * \lambda_1 + 0 * \lambda_2 - \delta \leq 220 \\
&\lambda_1 + \lambda_2 = 1 \\
&\lambda_1, \lambda_2, \delta \geq 0
\end{aligned}
$$

where: λ_i = weight on *i*th iteration of the B-B dispatch

δ = amount by which we are not meeting the hydropower maximum energy constraint

and the solution is: λ_1 = .8381, , λ_2 = .1619, δ = 0, π_1 = 285.7, π_2 = -81600,

z = 18742.86

where: π_1 = the shadow price on the hydropower constraint

π_2 = the shadow price on the lambda constraint

STEP 3: Because the value of hydropower is now 285.7, we will load Thermal 1 first, and load the hydropower second. Therefore,

E_{lc} = Expected load curtailment before loading any plants = 400 MW

E_1 = Expected load curtailment after loading Thermal 1

= .9 * 200 MW + .1 * 400 MW

= 220 MW

The expected generation of Thermal 1 = E_{lc} - E_1 = 180 MW and the expected generation costs = $2,592,000.

E_H = Expected load curtailment after loading Hydropower (on top of Thermal 1)

= .25 * .9 * 0 MW + .25 * .1 * 100 MW + . 75 * .9 * 0 MW +.75 * .1* 150 MW

= 13.75 MW

The expected generation from the Hydropower = E_1 - E_H = 206.25 MW. The expected load curtailment = 13.75 MW, the expected load curtailment costs = $2,970,000 and the total expected costs = $5,562,000 (or $7,725/hour).

The probability of Hydropower being on the margin = .25 * .9 + .75 * .9 = .9, the probability of Thermal 1 being on the margin = 0, and the probability of load curtailment being on the margin = .25 * .1 + .75 * .1 = .1 Therefore, the loss of load probability is .1.

To test for convergence:

(total costs + hydropower shadow price * hydropower generation + shadow price on λ constraint) = 7725 + 240*206.25 - 81600 = -14946 which is less than zero, therefore, the algorithm has not converged. We will go back to the Dantzig-Wolfe master problem and add a variable.

The third LP then is :

$$\begin{aligned}
&\min z \\
&z = 6600 * \lambda_1 + 81600 * \lambda_2 + 7725 * \lambda_3 + 3000 * \delta \\
&s.t. \\
&262.5 * \lambda_1 + 0 * \lambda_2 + 206.25 * \lambda_3 - \delta \leq 220 \\
&\lambda_1 + \lambda_2 + \lambda_3 = 1 \\
&\lambda_1, \lambda_2, \lambda_3, \delta \geq 0
\end{aligned}$$

where: λ_i = weight on *i*th iteration of the B-B dispatch

δ = amount by which we are not meeting the hydropower maximum energy constraint

and the solution is: λ_1 = .24444, λ_2 = 0, λ_3 = .75556, δ = 0, π_1 = 20.,

π_2 = -11850, z = 7450

where: π_1 = the shadow price on the hydropower constraint

π_2 = the shadow price on the lambda constraint

STEP 4: Because the value of hydropower is now 20, we can load either Hydropower or Thermal 1 first. We will pick Thermal 1 first. Therefore,

E_{lc} = Expected load curtailment before loading any plants = 400 MW

E_1 = Expected load curtailment after loading Thermal 1

= .9 * 200 MW + .1 * 400 MW

= 220 MW

The expected generation of Thermal 1 = E_{lc} - E_1 = 180 MW and the expected generation costs = $2,592,000.

E_H = Expected load curtailment after loading Hydropower (on top of Thermal 1)

= .25 * .9 * 0 MW + .25 * .1 * 100 MW + . 75 * .9 * 0 MW +.75 * .1* 150 MW

= 13.75 MW

The expected generation from the Hydropower = E_1 - E_H = 206.25 MW. The expected load curtailment = 13.75 MW, the expected load curtailment costs = $2,970,000 and the total expected costs = $5,562,000 (or $7,725/hour).

To test for convergence:

(total costs + hydropower shadow price * hydropower generation + shadow price on λ constraint) = 7725 + 20*206.25 - 11850 = 0, therefore, the algorithm has converged.

The Final Solution:

The value of Hydropower is equal to the shadow price on the hydropower constraint in the last D-W master problem, which means in this case it is equal to $20/MWh.

The generation from each of the plants in the optimum solution is the sum over all iterations of the product of the weight (from the last D-W solution) in that iteration and the amount of generation in that iteration. Therefore,

The amount of generation from Hydropower = .24444 * 262.5 + 0 * 0 + .75556 * 206.25

= 220 MW

which is the maximum hydropower energy available.

The amount of generation from Thermal 1 = .24444* 123.75 + 0 * 180 + .75556 * 180

= 166.25 MW

The amount of load curtailment = .24444 * 13.75 + 0 * 220 + .75556 * 13.75

= 13.75 MW

Similarly, for the probability of being on the margin:

The probability of Hydropower being on the margin = .24444 * 0 + 0 * 0 + .75556 * .9

= .68

The probability of Thermal 1 being on the margin = .24444* .9 + 0 * 0 + .75556 * 0

= .22

The probability of load curtailment being on the margin = .24444 * .1 + 0 * 1

+ .75556 * .1 = .1

From the probability of being on the margin for each plant we can calculate marginal costs. Namely, marginal costs = .68 * $20/MWh + .22 * $20/MWh + .1 * $300/MWh

= $48/MWh

ADDITIONAL MODEL CAPABILITIES

Real world problems are, of course, much more complicated than the above examples, but these examples show the basic algorithm for solving the dispatch. Besides modeling thermal plants and hydropower plants as in the above examples, the ISAAC dispatch logic includes:

1. using a multiple segment load duration curve (similar to the one in Figure H1-1),
2. placing a minimum energy generation amount on the hydropower,
3. placing a future value on water that could be stored (a piecewise linear function, similar to the one shown in H1-2),
4. including a purchase market whose price can be specified on peak versus off-peak,
5. including a spot sales market whose price can be specified on peak versus off-peak,
6. including pumped hydropower as a possible resource where the pumping is done in the off-peak hours and the generating is done on peak.
7. modeling thermal minimums
8. cummulants as an alternative method for doing the B-B dispatch
9. more than one hydropower plant can be specified

The B-B algorithm uses a load duration curve in order to model the time-differentiation of loads. The implementation of the B-B algorithm in ISAAC uses a **multiple segment** approximation to the monthly load duration curve. The number of segments can be controlled by the users, but currently ISAAC is using four segments: on peak weekdays, on peak weekends, off peak weekends, and everything else. The dispatch loads resources under this load duration curve in the most economic manner (which also has the effect of trying to levelize marginal costs across the load segments). This is accomplished for all four load segments in the same way it was done for one load segment in the above examples.

Because the Pacific Northwest hydropower system has **minimum energy** generation limits as well as maximum energy limits, both are included in the D-W formulation. Adding a minimum energy limit simply adds an additional variable in the objective function (with a penalty for violating) and in the hydropower constraint of the LP.

The **future value of water** (which must be estimated before going into the dispatch) is specified to help determine whether the storable water should be used now or saved for future use. Several different values can be specified, each with an amount of energy associated with it. Including the future value of water into the algorithm is done by adding variables for each future value in both the objective function (with a coefficient equal to the future value of water) and the hydropower constraint. These variables represent how many megawatts of hydropower is generated at each value.

Both the **purchase markets** and **spot markets** are represented in the dispatch by thermal plants with no forced outage rates. The spot markets, however, are also included in the load. Therefore, whenever the thermal plant associated with the spot market is dispatched, it means we are not serving that market. To the extent the dispatch is displacing the spot market thermal plant, it means that spot market is being served by resources in the PNW and resultant secondary revenues are calculated.

The prices on both the purchase markets and spot markets can be time-differentiated by load blocks that are defined in a manner that is consistent with the specified load segments. Since these markets are modeled as thermal plants and since thermal plants are assumed to have one price over all of the load segments in the B-B algorithm, the ISAAC dispatch performs a B-B dispatch for each load block, within each iteration of the D-W algorithm. Therefore, the more load blocks that are defined, the more B-B dispatches are performed in each iteration, and the higher the run time.

Pumped hydropower can be modeled with pumping being done off peak and generating being done on peak where off peak and on peak are defined by the load blocks discussed above. The pumped hydropower plant is defined by a capacity, an efficiency, and which load blocks are used for pumping. Pumped hydropower is similar to hydropower in that it has no immediate costs, and is constrained by how much energy it can produce. Therefore, adding a pumped hydropower plant adds a constraint to the D-W LP that is similar to the hydropower energy constraint.

Thermal minimums can be modeled in two ways. One is similar to the hydropower minimum, in that there is a specified minimum energy amount that must be generated on average across all load segments. This minimum adds an additional constraint to the D-W LP that is similar to the hydropower energy constraint. The other thermal minimum modeled is one in which the thermal plant must generate a minimum amount in each load segment. This constraint is modeled simply as a subtraction off the load duration curve.

The examples in Section C use the exact capacity probability distribution for determining the expected remaining load not served after loading each plant. **Cummulants** are a method of approximating these probability distributions, which is computationally much faster. ISAAC has cummulants as an option in order to speed up run time.

By using the D-W decomposition method for solving the dispatch, ISAAC has the option of running the dispatch with **more than one hydropower plant**. Because ISAAC currently only has a one-dam model, only one hydropower plant is currently being modeled. However, multiple hydropower plants are possible in the future, or other resources that act like hydropower (e.g. some contracts) could be modeled.

More detailed explanation of each of these concepts can be found in the following section on Mathematical Theory.

MATHEMATICAL THEORY BEHIND THE ISAAC DISPATCH

Introduction

The need to represent uncertainties of future operating conditions in power system planning and operations is widely recognized by the utility industry. *Probabilistic production costing* (PPC) models, which evaluate the expected unit operating costs along the planning period, taking into account equipment outages and load variation, are especially relevant for utility studies.

PPC Formulation - Thermal Systems

The PPC of a thermal generating system is represented as the following *stochastic optimization* problem:

$$z = \quad \text{Min} \quad \sum_{j=1}^{J} c_j \, g_j \qquad (1.1)$$

subject to

$$\sum_{j=1}^{J} g_j \geq d \tag{1.2}$$

$$g_j \leq \overline{g}_j \tag{1.3}$$

for $j = 1, \ldots, J$

where:

j indexes the generating units

J number of units

c_j unit operation cost of the j^{th} unit

g_j generation of the j^{th} unit

d system demand (random variable)

$\overline{g}_j$ generation capacity of the j^{th} unit (random variable)

The objective function (1.1) is to minimize the total generation cost. Constraint (1.2) represents the system load supply. The set of constraints (1.3) represents the generation limit of each unit. The PPC problem is to calculate the expected generation cost, $E(z)$, taking into account load fluctuations and random equipment outages.

Analytical Solution of the PPC

Stochastic LP problems are in general quite difficult to solve. However, the PPC problem (1) can be efficiently solved by a method originally proposed by Baleriaux. The Baleriaux scheme decomposes the production costing problem into J generation reliability evaluation subproblems. In turn, the reliability problems reduce to the comparison between the distribution of available capacity and system demand, which is carried out by discrete convolution. The Baleriaux scheme is thus accurate and very fast, especially when series expansion techniques (or cummulants) are used to carry out the required convolutions.

The Baleriaux scheme is widely used by utilities in their production costing and expansion planning studies. It is also implemented in several popular computer packages such as PROMOD, WASP and EGEAS.

Overview of the Baleriaux Scheme

The Baleriaux algorithm is summarized in the following steps:

1. Assume that the generating units are ranked by increasing operating cost. Remove all units from problem (1), except the cheapest (g_1, in this case), and solve the following stochastic subproblem:

$$w_1 = \quad \text{Min} \quad \delta$$

$$\text{subject to} \tag{2}$$

$$\delta + g_1 \geq d$$

$g_1 \leq \bar{g}_1$

where δ is a scalar variable, representing the *load curtailment* in the system due to insufficient generating capacity.

2. Problem (2) is a *generation reliability* evaluation problem, for which efficient solution algorithms are available. In this particular case, the problem is easily solved by setting:

$$w_1 = \text{Max} \{ 0, d - \bar{g}_1 \} \qquad (3)$$

that is, the available generation is used up to its maximum capacity or up to the demand value. The expected value of w_1 is calculated by the convolution of the probability distributions of d and $\bar{g}_1$.

3. Next, we calculate the contribution of generating unit 1:

$$\Delta_1 = E(d) - E(w_1) \qquad (4)$$

where $E(d)$ is the mean system load. The difference Δ_1 represents the expected generation of unit 1 in the reliability problem (2).

4. The Baleriaux approach is based on the fact that Δ_1 is also the expected generation of unit 1 in the solution of the *original* PPC problem (1). The intuitive reason is that unit 1, being the cheapest, is used at its maximum capacity to meet the demand of problem (2), before the more expensive units are loaded.

5. The above procedure is repeated for each unit in the system. The reliability evaluation problem, after the addition of the n^{th} unit, becomes:

$$w_n = \text{Min} \quad \delta$$

subject to (5)

$$\delta + \sum_{j=1}^{n} g_j \geq d$$

$$g_j \leq \bar{g}_j$$

for $j = 1, \ldots, n$

The solution of problem (5) is similar to that of problem (2):

$$w_n = \text{Max} \{ 0, d - \sum_{j=1}^{n} \bar{g}_j \} \qquad (6)$$

As in (2), the expected value of w_n, $E(w_n)$, is analytically obtained by convolution of the load d and of the n generation capacities $\{\bar{g}_j\}$. Note that $E(w_n)$ can be recursively obtained from the convolutions carried out for unit w_{n-1}, adding unit n.

The same reasoning applied to the first unit shows us that the difference between $E(w_n)$ and $E(w_{n-1})$ corresponds to the mean generation of the n^{th} unit in the PPC problem (1):

$$\Delta_n = E(w_{n-1}) - E(w_n) \qquad (7)$$

6. The expected value of the total generation cost in the PPC problem (1) is given by:

$$E(z) = \sum_{j=1}^{J} c_j \, \Delta_j \qquad (8)$$

In summary, the Baleriaux approach decomposes the PPC problem (1) into *J* subproblems of calculating the mean load curtailment, which can be easily solved by analytical methods.

Representation of Energy-Limited Plants

The PPC problem (1) represents adequately capacity limitations in the system plants due, for example, to forced outages. However, it does not represent limits on the energy generated along the study period. These energy limits may be imposed by environmental constraints, in the case of thermal units, or by lack of water, in the case of hydropower units.

Representation of One Energy-Limited Plant

We will initially formulate the PPC for a system composed of one hydropower unit and *J* thermal units.

$$z = \text{Min} \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j \, g_{js} \right\} \qquad (9.1)$$

subject to

$$\sum_{j=1}^{J} g_{js} + h_s \geq d_s \qquad (9.2)$$

$$g_{js} \leq \bar{g}_{js} \qquad (9.3)$$

$$h_s \leq \bar{h}_s \qquad (9.4)$$

$$\sum_{s=1}^{S} P(s) \, h_s \leq E \qquad (9.5)$$

for $j = 1, \ldots, J$; for $s = 1, \ldots, S$

where:

s indexes the system *scenarios*, resulting from the combinations of equipment outages and load levels

S is the number of system scenarios

$P(s)$ probability of scenario s

g_{js} generation of plant j in scenario s

$\bar{g}_{js}$ capacity of thermal plant *j* in scenario *s* (note that the plant capacity varies with the scenarios due to equipment outages)

h_s hydropower plant generation in scenario *s*

$\bar{h}_s$ hydropower plant capacity in scenario *s*

E limit on hydropower energy generation

Constraints (9.2) through (9.4) represent respectively the system load supply equation and capacity limits for the thermal and hydropower plants, similarly to the original PPC (1). Constraint (9.5) indicates that the expected generation of the hydropower plant should not exceed the energy limit, E.

Solution Scheme

The only structural difference between the hydropower-thermal problem (9) and the all-thermal problem (1) is the coupling constraint (9.5). This constraint can be removed by Lagrangean relaxation, i.e. by assigning a cost λ to the hydropower generation and adding it to the objective function:

$$z = \text{Min} \sum_{s=1}^{S} P(s) \{ \sum_{j=1}^{J} c_j \, g_{js} + \lambda \, h_s \} \qquad (10.1)$$

subject to

$$\sum_{j=1}^{J} g_{js} + h_s \geq d_s \qquad (10.2)$$

$$g_{js} \leq \bar{g}_{js} \qquad (10.3)$$

$$h_s \leq \bar{h}_s \qquad (10.4)$$

In problem (10), the hydropower unit is modeled as a dummy thermal unit with operating “cost” λ. This cost determines the position of the hydropower unit in the loading order of the generating units. The Baleriaux procedure described in Section 3 can then be used to calculate the expected generation of the hydropower plant.

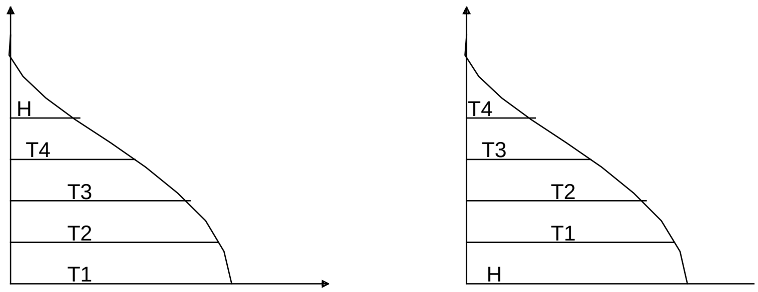
The idea is then to vary the value of λ until the expected hydropower generation matches the energy target E_h. This problem can be efficiently solved by the following procedure:

a) solve the standard PPC (1) with the hydropower plant at the *last* position in the loading order, that is: $\{T_1, T_2, ..., T_J, H\}$. Calculate the expected energy generated by the hydropower and thermal plants, and the corresponding system operation costs.

b) solve the standard PPC (1) with the hydropower plant at the *first* position in the loading order, that is: $\{H, T_1, T_2, ..., T_J\}$. Calculate the expected energy generated by the hydropower and thermal plants, and the corresponding system operation costs. Figure H1-4 illustrates both calculations.

Figure H1-4

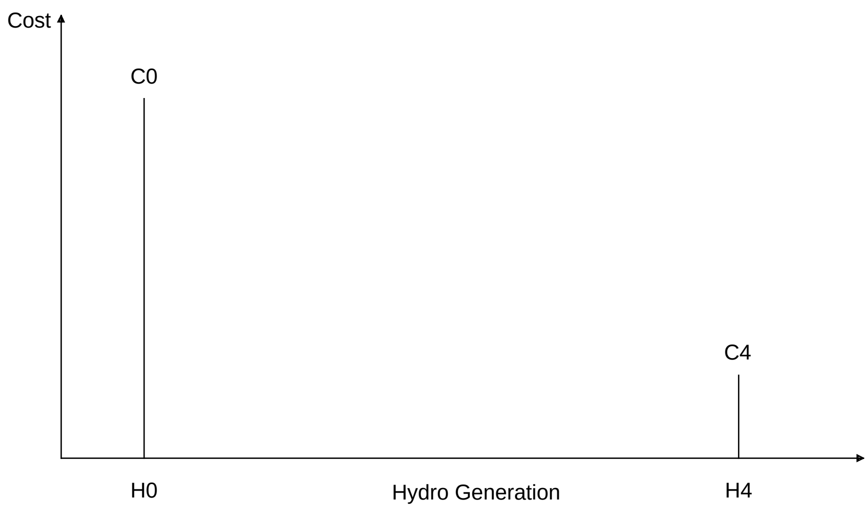
Calculation of Initial Points of Cost x Hydropower Energy Curve



c) *p*lot the expected hydropower generation values obtained in (*a*) and (*b*), and the corresponding system operation costs, as the two extreme points of a *cost x hydropower energy* curve, illustrated in Figure H1-5.

Figure H1-5

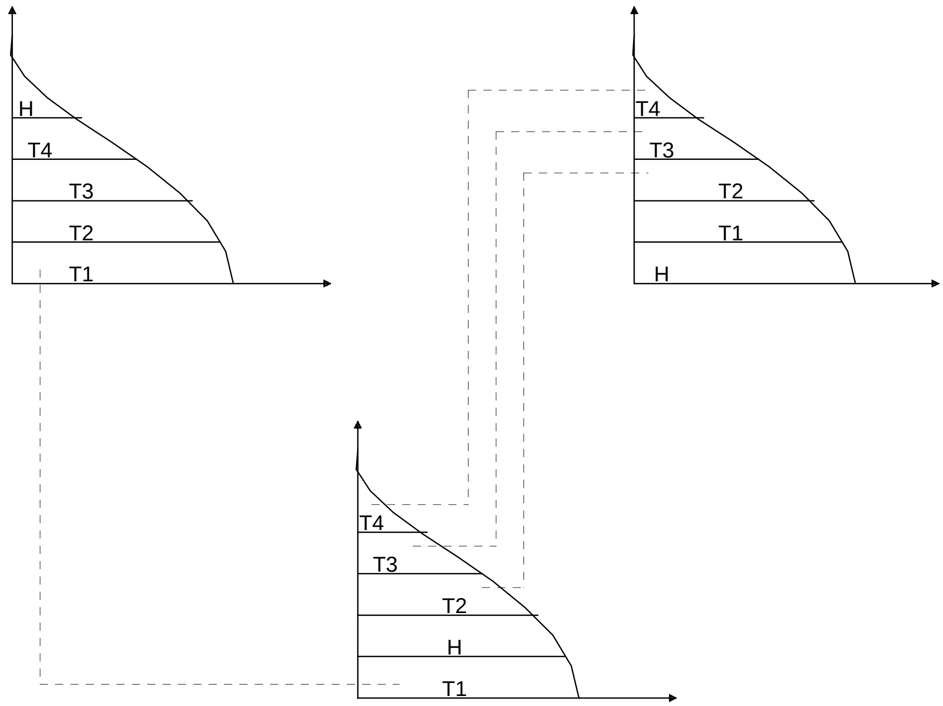
Initial Points of Cost × Hydropower Energy Curve



d) calculate the expected hydropower generation and system operation cost associated to each intermediate loading point, e.g. $\{T_1, H, T_2, \ldots, T_J\}$. Note that it is *not* necessary to carry out additional PPC runs. The mean generation of T_1 comes from the PPC run in (*a*), in which the hydropower was last in the loading order. The reason is that the expected generation of a given plant does *not* depend on which plants come *after* in the loading order. In turn, the mean generation of each of the remaining plants i, $\{T_3, \ldots, T_J\}$ comes from the PPC run in (*b*). The reason is that the expected generation of a given plant does not depend on the loading *order* of the *previous* plants. Finally, the expected hydropower generation is calculated as the *difference* between the expected demand and the expected thermal generations. The procedure is shown in Figure H1-6.

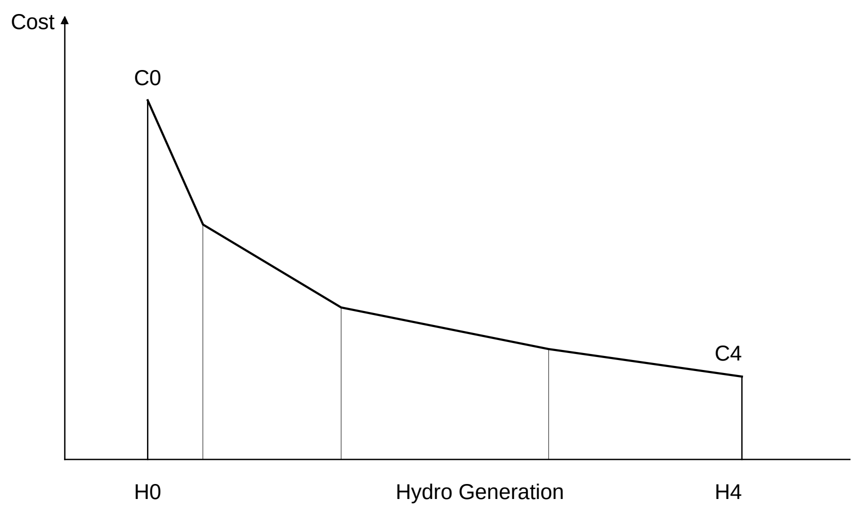
Figure H1-6

Calculation of Intermediate Points in the Cost x Energy Curve



e) plot the intermediate values calculated in step (*d*) in the cost × hydropower generation curve, and join the points by linear segments, as illustrated in Figure H1-7.

Figure H1-7
Cost × Hydropower Generation Curve



The resulting curve allows us to determine the expected operation cost associated to any hydropower energy target, taking into account equipment outages and load variation.

Representation of Multiple Energy-Limited Plants

Problem Formulation

We now assume that there are H hydropower plants in the PPC problem:

$$z = \quad \text{Min} \quad \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j \, g_{js} \right\}$$

subject to (11)

$$\sum_{j=1}^{J} g_{js} + \sum_{i=1}^{H} h_{is} \geq d_s$$

$$g_{js} \leq \bar{g}_{js}$$

$$h_{is} \leq \bar{h}_{is}$$

$$\sum_{s=1}^{S} P(s) \, h_{is} \leq E_i$$

for $j = 1, \ldots, J$; $i = 1, \ldots, H$; $s = 1, \ldots, S$

In principle, we can use the same Lagrangean relaxation procedure of Section 4.2 to construct a multi-dimensional cost × hydropower energy curve. Note, however, that the curve now depends on the hydropower generation of each of the H plants. Therefore, we would need to carry out PPC runs for all 2H combinations of hydropower plants at the top and bottom of the loading order, which becomes computationally expensive if there is a large number of energy-limited plants.

Proposed Solution Scheme

Our proposed solution approach is to *generate only* the part of the curve corresponding to the desired energy targets. For notational simplicity, we will initially assume that there is only one hydropower plant, as in problem (9). We will then generalize the procedure to an arbitrary number of plants.

Let us formulate the following problem:

$$z(\tilde{h}) = \quad \text{Min} \quad \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j \, g_{js} \right\}$$

subject to (12)

$$\sum_{j=1}^{J} g_{js} + h_s \geq d_s$$

$$g_{js} \leq \bar{g}_{js}$$

$$h_s \le \bar{h}_s$$

$$\sum_{s=1}^{S} P(s)\, h_s = \tilde{h}$$

for $j = 1, \ldots, J$; $s = 1, \ldots, S$, and where $\tilde{h}$ is the mean hydropower generation.

The original problem (11) can be rewritten as:

$$\begin{aligned} z = \quad & \min_{\tilde{h}} \quad z(\tilde{h}) \\ & \text{subject to} \\ & \qquad \tilde{h} \le E \end{aligned} \qquad (13)$$

Representation of $z(\tilde{h})$ as a piecewise linear function

From LP theory, we know that $z(\tilde{h})$ is a piecewise linear function of $\tilde{h}$. Consider the following LP problem:

$$\begin{aligned} z(b) = \quad & \text{Min} \quad cx \\ & \text{s.to} \quad Ax \ge b \\ & \qquad\quad x \ge 0 \end{aligned} \qquad (14)$$

The dual of this problem is:

$$\begin{aligned} & \text{Max} \quad \pi b \\ & \text{s.to} \quad \pi A \le c \\ & \qquad\quad \pi \ge 0 \end{aligned} \qquad (15)$$

Let Π be the set of feasible solutions, that is $\Pi = \{\ \pi \ge 0\ /\ \pi A \le c\ \}$ and let $\pi^1, \pi^2, \ldots, \pi^P$ be the P vertices of this set. The dual problem can be rewritten as

$$\max_{i=1\ldots P} \quad \pi^i b \qquad (16)$$

or, equivalently,

$$\begin{aligned} & \text{Min} \quad \alpha \\ & \text{s.to} \quad \alpha \ge \pi^i b \quad i = 1, \ldots, P \end{aligned}$$

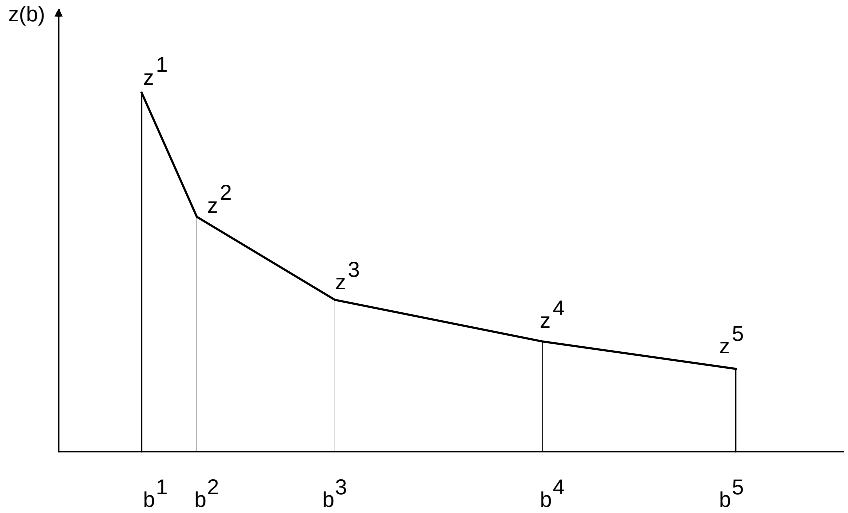
where α is a scalar variable. From dual and primal equality we can see that z(b) is equal to (16)

$$\begin{aligned} z(b) = \quad & \text{Min} \quad \alpha \\ & \text{s.to} \quad \alpha \ge \pi^i b \quad i = 1, \ldots, P \end{aligned} \qquad (17)$$

Problem (17) characterizes a piecewise linear curve, as illustrated in Figure H1-8.

Figure H1-8

z(b) is a piecewise linear function of *b*



Any piecewise linear function can be written as a convex combination of its breakpoints. Then the *z(b)* function can be written as

$$z(b) = \text{Min} \sum_{k=1}^{P} \lambda_k z^k$$

(18)

$$\text{s.to} \quad b = \sum_{k=1}^{P} \lambda_k b^k$$

$$\sum_{k=1}^{P} \lambda_k = 1$$

where $z^k = z(b^k)$

Reformulation of the energy-limited plant problem

It was shown in the previous section that $z(\tilde{h})$ is a piecewise linear curve. Problem (13) can then be reformulated as in (18).

$$\text{Min} \sum_{k=1}^{P} \lambda_k z^k$$

s.to (19)

$$\sum_{k=1}^{P} \lambda_k \tilde{h}^k \le E$$

$$\sum_{k=1}^{P} \lambda_k = 1$$

where the values zk correspond to the breakpoints in the piecewise cost × hydropower energy curve.

Rewriting (19) in the standard LP format, we have:

Min	$\sum_{k=1}^{P} \lambda_k z^k$	Simplex Multipliers
s.to		(20)
	$-\sum_{k=1}^{P} \lambda_k \tilde{h}^k \geq -E$	π
	$\sum_{k=1}^{P} \lambda_k = 1$	μ

Problem (20) can be solved by Dantzig-Wolfe decomposition. The DW scheme iteratively generates the "relevant" columns for the LP problem, called Dantzig-Wolfe master problem.

From LP theory we know that the addition of each column to the basis or the optimality check is associated to the calculation of the most negative reduced cost. The reduced cost of variable lk is:

$$\bar{c}k = zk - \pi \times (-\tilde{h}k) - \mu \times 1 \quad (21)$$

The most negative reduced cost is determined as:

$$\bar{c}_{min} = \underset{\tilde{h}}{\text{Min}}\ z(\tilde{h}) + \pi \times \tilde{h} - \mu \quad (22)$$

Substituting (12) into (22), we have:

$$\bar{c}_{min} = \text{Min} \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j\, g_{js} \right\} + \pi \times \tilde{h} - \mu \quad (23)$$

subject to

$$\sum_{j=1}^{J} g_{js} + h_s \geq d_s \quad (23a)$$

$$g_{js} \leq \bar{g}_{js} \quad (23b)$$

$$h_s \leq \bar{h}_s \quad (23c)$$

$$\sum_{s=1}^{S} P(s)\, h_s = \tilde{h} \quad (23d)$$

Replacing constraint (23d) in the objective function, we have:

$$\bar{c}_{min} = \text{Min} \quad \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j\, g_{js} + \pi \times h_s \right\} - \mu$$

subject to (24)

$$\sum_{j=1}^{J} g_{js} + h_s \geq d_s$$

$$g_{js} \leq \bar{g}_{js}$$

$$h_s \leq \bar{h}_s$$

Problem (24) is a traditional PPC problem, considering the hydropower plant as a thermal plant with an artificial cost given by π. This problem can be solved by the Baleriaux scheme presented in Section 3.

In the Dantzig-Wolfe decomposition scheme, problem (24) is known as Dantzig-Wolfe subproblem. From the solution of this problem, we have two alternatives:

- If $\bar{c}_{min} = 0$, then optimality is achieved
- If $\bar{c}_{min} < 0$, then we produce a new column $[z^k, \tilde{h}^k]$ for the Dantzig-Wolfe master problem, obtained from the solution of (24).

After the addition of the new column the Dantzig-Wolfe master problem, becomes:

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k z^k$$

s.to (25)

$$\sum_{k=1}^{K} \lambda_k \tilde{h}^k \leq E$$

$$\sum_{k=1}^{K} \lambda_k = 1$$

where K is the number of columns added, one for each iteration.

The steps of the iterative algorithm are summarized below.

a) Initialize $K = 1$, and solve the PPC (24) with the hydropower plant in the first position of the loading order. Calculate z^1 and $\tilde{h}^1$.

b) Solve the master problem:

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k z^k + p\sigma \qquad \text{Simplex Multiplier} \qquad (26)$$

subject to

$$\sum_{k=1}^{K} \lambda_k \tilde{h}^k + \sigma \leq E \qquad \pi$$

$$\sum_{k=1}^{K} \lambda_k = 1 \qquad \mu$$

where σ is a penalty variable that ensures the mathematical feasibility of the energy limit constraint. The penalty cost, p, is assumed to be very high.

c) Let π be the simplex multiplier associated to the energy constraint at the optimal solution of (26). Assign the value π *as an* artificial cost to the hydropower plant, obtain a new loading order, re-solve the PPC (24) and compute $\bar{c}_{min}$. If $\bar{c}_{min}$ = 0, then STOP.

d) Let $K \leftarrow K + 1$, and let z^K and $\tilde{h}^K$ be the expected operation cost and the expected hydropower generation resulting from the PPC run in step (*c*). Add the new column to the relaxed problem (26) and go to step (*b*)

Extension for the multiple hydropower plant case

In the case of H energy-limited hydropower plants the Dantzig-Wolfe master problem is:

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k z^k \qquad \text{Simplex Multiplier}$$

$$\text{s.to} \qquad (27)$$

$$\sum_{k=1}^{K} \lambda_k \tilde{h}_i^k \leq E_i \qquad i = 1,\ldots, H \qquad \pi$$

$$\sum_{k=1}^{K} \lambda_k = 1 \qquad \mu$$

where: E_i is the energy target associated to hydropower *i*.

$\tilde{h}_i^k = \sum_{s=1}^{S} P(s)\, h_{is}$ is the mean generation for hydropower *i*.

Let πi be the simplex multiplier associated to the standard format of the above problem for the ith hydropower plant

The Dantzig-Wolfe subproblem is given by:

$$\bar{c}_{min} = \text{Min} \quad \sum_{s=1}^{S} P(s) \left\{ \sum_{j=1}^{J} c_j\, g_{js} + \sum_{i=1}^{H} \pi_i\, h_{is} \right\} - \mu$$

subject to (28)

$$\sum_{j=1}^{J} g_{js} + \sum_{i=1}^{H} h_{is} \geq d_s$$

$$g_{js} \leq \bar{g}_{js}$$

$$h_{is} \le \bar{h}_{is}$$

Problem (28) And this is also a traditional PPC problem with H hydropower plants represented as thermal plants, with artificial costs π_i.

Representation of Lower and Upper Targets

We will now extend the methodology to also represent lower bound on the energy target. For notational simplicity, let us assume that there is only one hydropower plant.

$$\begin{aligned}
\text{Min} \quad & \sum_{k=1}^{K} \lambda_k z^k \\
\text{s.to} \quad & \\
& E_{lower} \le \sum_{k=1}^{K} \lambda_k \tilde{h}^k \le E_{upper} \\
& \sum_{k=1}^{K} \lambda_k = 1
\end{aligned} \tag{29}$$

where: E_{upper} upper limit for hydropower generation

E_{lower} lower limit for hydropower generation

Depending on the values of E_{lower} and E_{upper} this problem may be infeasible. We then include penalties associated to target violations. Let:

$$\phi = \sum_{k=1}^{K} \lambda_k \tilde{h}^k - E_{lower} \tag{30}$$

Then the constraint $E_{lower} \le \sum_{k=1}^{K} \lambda_k \tilde{h}^k \le E_{upper}$ in (29) can be rewritten as:

$$\sum_{k=1}^{K} \lambda_k \tilde{h}^k - \phi = E_{lower} \tag{31}$$

$$\phi \le E_{upper} - E_{lower}$$

$$\phi \ge 0$$

The Dantzig-Wolfe master problem is formulated as:

$$\begin{aligned}
\text{Min} \quad & \sum_{k=1}^{K} \lambda_k z^k + p\,(\sigma_{lower} + \sigma_{upper}) \\
\text{s.to} \quad & \\
& \sum_{k=1}^{K} \lambda_k \tilde{h}^k - \phi + \sigma_{lower} - \sigma_{upper} = E_{lower} \\
& \phi \le E_{upper} - E_{lower}
\end{aligned} \tag{32}$$

$$\sum_{k=1}^{K} \lambda_k = 1$$

where: p is a penalty cost for the violation of target constraints

ϕ is the artificial variable defined in (30)

σ_{lower} and σ_{upper} are slack variables that ensure the feasibility of target constraints.

Observe that only the master problem is modified. The PPC subproblem and the steps of the algorithm remain the same.

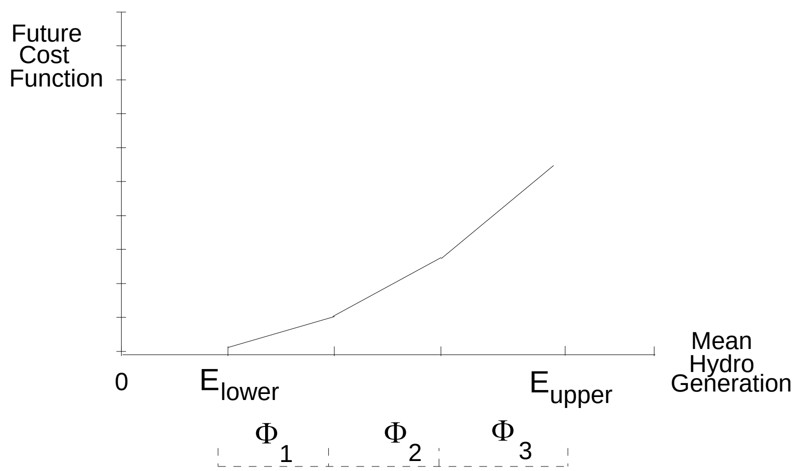
Representation of future cost function for hydropower plants

In this section, we will allow the representation of the future cost function of hydropower generation as a piecewise linear function.

For notational simplicity we assume that there is only one hydropower plant, and that the future cost function has three segments as shown in Figure H1-9:

Figure H1-9

Future Cost Function



As seen in Figure H1-9, each segment of the mean hydropower generation axis in the future cost function, is represented Φ_i, i = 1,...,3. Naturally $\Phi_1 + \Phi_2 + \Phi_3 = E_{upper} - E_{lower}$.

As in the previous case we will change variables and use artificial variables ϕ_1, ϕ_2 and ϕ_3.satisfying:

$$\phi_1 + \phi_2 + \phi_3 = \sum_{k=1}^{K} \lambda_k \tilde{h}^k - E_{lower} \tag{33}$$

$$\phi_i \le \Phi_i \qquad i = 1, ..., 3$$

The Dantzig-Wolfe master problem for one hydropower plant with target constraint and future cost function is formulated as follows:

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k z^k + f_1\phi_1 + f_2\phi_2 + f_3\phi_3 + p\,(\sigma_{lower} + \sigma_{upper}) \tag{34}$$

subject to

$$\sum_{k=1}^{K} \lambda_k \tilde{h}^k - \phi_1 - \phi_2 - \phi_3 + \sigma_{lower} - \sigma_{upper} = E_{lower}$$

$$\sum_{k=1}^{K} \lambda_k = 1$$

$$\phi_i \le \Phi_i \qquad i = 1, 2, 3$$

where:

f_i: Incremental cost of each segment of the future cost function

The general formulation of (34) for a future cost function with L segments is:

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k z^k + \sum_{l=1}^{L} f_l\phi_l + p\,(\sigma_{lower} + \sigma_{upper}) \tag{35}$$

subject to

$$\sum_{k=1}^{K} \lambda_k \tilde{h}^k - \sum_{l=1}^{L} \phi_l + \sigma_{lower} - \sigma_{upper} = E_{lower}$$

$$\sum_{k=1}^{K} \lambda_k = 1$$

$$\phi_l \le \Phi_l \qquad l = 1,\dots, L$$

where:

f_l: Incremental cost of each segment of the future cost function

Representation of pumped-storage plants

Pumped storage plants are plants that pump water to an upper storage reservoir during the off-peak load segments. This pumped volume is used to generate energy during the peak load segments. They are characterized by their generation capacity $\bar{C}$ (MW) and an efficiency coefficient β. Let us define:

$\tilde{q}_{off}$ mean energy pumped during off-peak load segments

$\tilde{q}_{on}$ mean energy pumped during on-peak load segments

t_{off} duration of the off-peak load segments

The pumped-storage generation must satisfy the following constraint:

$$\tilde{q}_{on} \le \beta \times \tilde{q}_{off} \qquad (36)$$

or, equivalently,

$$\tilde{q}_{on} - \beta \times \tilde{q}_{off} \le 0 \qquad (37)$$

This constraint is included in the Dantzig-Wolfe master problem.

The pumped-storage plan is represented in the probabilistic production costing as follows:.

- In the off-peak load segments we add the pumped capacity $\bar{C}$ to the load. We represent the pumped-storage as an artificial "thermal" plant whose generation $\tilde{g}_{off}$ represents the *curtailment* of this load. The mean energy pumped is then:

$$\tilde{q}_{off} = \bar{C}\, t_{off} - \tilde{g}_{off} \qquad (38)$$

- In the peak load segments we represent the pumped-storage as a normal generator, with no change in the load.

Substituting (38) in (37), we have:

$$\tilde{q}_{on} + \beta \times \tilde{g}_{off} \le \beta\, \bar{C}\, t_{off} \qquad (39)$$

The master problem is

$$\text{Min} \quad \sum_{k=1}^{K} \lambda_k (z^k_{on} + z^k_{off}) + \sum_{l=1}^{L} f_l \phi_l + p\,(\sigma_{lower} + \sigma_{upper}) \qquad \text{Simplex multipliers}$$

subject to (40)

$$\sum_{k=1}^{K} \lambda_k (\tilde{h}^k_{on} + \tilde{h}^k_{off}) - \sum_{l=1}^{L} \phi_l + \sigma_{lower} - \sigma_{upper} = E_{lower} \qquad \pi$$

$$\sum_{k=1}^{K} \lambda_k (\tilde{q}^k_{on} + \beta\, \tilde{g}^k_{off}) \le \beta\, \bar{C}\, t_{off} \qquad \eta$$

$$\sum_{k=1}^{K} \lambda_k = 1 \qquad \mu$$

$$\phi_l \le \Phi_l \qquad l = 1, \ldots, L$$

In this case the reduced cost is

$$\bar{c}_k = z^k + \pi \times (\tilde{h}^k_{on} + \tilde{h}^k_{off}) + \eta \times (\tilde{q}^k_{on} + \beta\, \tilde{g}^k_{off}) - \mu \times 1$$

(41)

We have to solve two separate PPCs, one for each set of load segments (peak and off-peak):

For the off-peak load PPC subproblem we consider:

- a modified demand (original demand plus pump capacity)

- the hydropower plant as a “thermal” generator with artificial cost π
- an artificial generator that represents “pump curtailment” with artificial cost $\eta \times \beta$.

For the peak load PPC subproblem we consider:

- the original demand;
- the hydropower plant as a "thermal" generator with artificial cost π;
- the pump-storage plant as a "thermal" generator with artificial cost η

Representation of Spot Markets

Spot markets are characterized by the amount of energy ($\bar{E}_{spot}$) a consumer is willing to purchase at a given energy price (c_{spot}). The spot markets are represented in the PPC subproblem as follows:

- Add the value of the Spot Market $\bar{E}_{spot}$ to the load
- Represent the curtailment of this spot market as an artificial plant with operation cost c_{spot} and maximum generation capacity $\bar{E}_{spot}$.

The master problem does not change.

Calculation of Marginal Costs

The short term marginal cost is the derivative of the total cost with respect to the demand.

For notational simplicity, assume that we have only one hydropower plant with no future cost function, and no pumped-storage plants or spot markets. Then the Dantzig-Wolfe master problem is as in (20):

$$z = \text{Min} \sum_{k=1}^{K} \lambda_k z^k \qquad \text{Simplex Multipliers}$$

$$\text{s.to} \qquad (42)$$

$$\sum_{k=1}^{K} \lambda_k (-\tilde{h}^k) \geq -E \qquad \pi$$

$$\sum_{k=1}^{K} \lambda_k = 1 \qquad \mu$$

We know that both z^k and $\tilde{h}^k$ depend on the demand d. Consider the following LP problem:

$$\begin{aligned} z = \quad & \text{Min} \quad c(d)\, x && \text{Simplex Multiplier} \\ & \text{s.to} \quad A(d)x \geq b && \pi \qquad (43) \\ & \qquad\quad x \geq 0 \end{aligned}$$

We know that Problem (43) is equivalent to optimizing the Lagrangean function.

$$z = L(x,\pi) = c(d)\, x - \pi(A(d)x - b) \qquad (44)$$

The derivative of z with respect to d in (44) is:

$$\frac{\partial z}{\partial d} = \frac{\partial c(d)}{\partial d} x - \pi x \frac{\partial A(d)}{\partial d} \qquad (45)$$

Applying (45) to our original problem we have:

$$\frac{\partial z}{\partial d} = \sum_{k=1}^{K} \lambda_k \frac{\partial z^k}{\partial d} - \pi \sum_{k=1}^{K} \lambda_k \frac{\partial(-\tilde{h}^k)}{\partial d} \qquad (46)$$

Calculation of $\frac{\partial \tilde{h}^k}{\partial d}$

From the Baleriaux solution scheme we know that:

$$\tilde{h}^k = E(w_{i-1}^k) - E(w_i^k) \qquad (47)$$

where: i indicates the load order of hydropower plant in the kth iteration.

$E(w_i^k)$ is the expected value of the energy not supplied after loading the ith plant

We know that the derivative of the energy not supplied with respect to load is the loss of load probability. Therefore,

$$\frac{\partial \tilde{h}^k}{\partial d} = LOLP_{i-1}^k - LOLP_i^k \qquad (48)$$

where $LOLP_i^k$ is the loss of load probability after loading the ith plant.

Expression (48) is rewritten as:

$$\frac{\partial \tilde{h}^k}{\partial d} = \Delta LOLP^k \qquad (49)$$

where $\Delta LOLP^k = LOLP_{i-1}^k - LOLP_i^k$

Calculation of $\frac{\partial z^k}{\partial d}$

Let c_i be the cost of the plant loaded in order i and c_{def} be the deficit cost. Then

$$z = \sum_{i=1}^{n} c_i (E(w_{i-1}^k) - E(w_i^k)) + c_{def} \ E(w_n^k) \qquad (50)$$

Let $LOLP_i^k$ be the loss of load probability of the system after loading the ith plant in the kth iteration. Then:

$$\frac{\partial z^k}{\partial d} = \sum_{i=1}^{n} c_i (LOLP_{i-1}^k - LOLP_i^k) + c_{def} \ LOLP^k \qquad (51)$$

Therefore:

$$\frac{\partial z}{\partial d} = \sum_{k=1}^{K} \lambda_k \sum_{i=1}^{n} c_i (LOLP_{i-1}^{k} - LOLP_{i}^{k}) + c_{def} \sum_{k=1}^{K} \lambda_k LOLP^{k} + \pi \sum_{k=1}^{K} \lambda_k \Delta LOLP^{k} \qquad (52)$$

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APPENDIX H2

A TRAPEZOIDAL APPROXIMATION TO THE PACIFIC NORTHWEST HYDROPOWER SYSTEM'S EXTENDED HOURLY PEAKING CAPABILITY USING LINEAR PROGRAMMING

APPENDIX H2

A TRAPEZOIDAL APPROXIMATION TO THE PACIFIC NORTHWEST HYDROPOWER SYSTEM'S EXTENDED HOURLY PEAKING CAPABILITY USING LINEAR PROGRAMMING

Overview

The trapezoidal approximation is a linear programming-based estimate of the Pacific Northwest's (PNW) hydropower systems peaking capability. By approximating the Pacific Northwest's twin peak load shape to be that of a trapezoid, linear programming can be used to approximate the extended hourly peaking capability of the hydropower system. This approximation is useful for production cost and unit operation studies. It is not intended nor is it valid for peak reliability studies.

Why a Trapezoid?

One basic assumption underlies the trapezoidal approximation to the sustained peaking capability of the Pacific Northwest (PNW) hydropower system. We assume the Pacific Northwest load is sufficiently trapezoidal in shape that the capacity capability of the hydropower system can be ascertained by finding the hydropower system's ability to meet a trapezoidal shape. By trapezoidal we mean a flat on-peak period and a flat off-peak period connected by two equal duration ramping periods. There is an implicit assumption that the deviations of the load about the trapezoid are within the capabilities of the hydropower system. There is also an implicit assumption that the various constraints put on changes in hourly and daily output can be reasonably approximated by one ramp rate constraint.

It is recognized that the trapezoidal approximation is not an adequate model to assess capacity reliability, but it seems a reasonable approximation for finding the influence of capacity on production costs. The Bonneville Power Administration compared the results of the trapezoidal approximation to two of their hourly models and found consistent results.

Accounting For All the Projects

There is not general agreement on what projects need to be included in an hourly model of the capability of the Northwest hydropower system. The differences center on projects on smaller river systems. These projects represent about 2 percent of the peaking capability and have a mixed record of responding to regional peak loads. The projects explicitly modeled in the trapezoidal approximation are shown on Page H2-8. For the purpose of the following discussion the rest of the projects fall into two categories:

1. projects that are modeled explicitly in the regulator but are not modeled explicitly in the trapezoidal approximation,
2. projects not modeled explicitly in either the regulator or the trapezoidal approximation, the so called "hydropower independents."

Page H2-12 contains the description of both the relationship between plants and the physical parameters of the plants explicitly modeled in the Trapezoidal Approximation.

Assumptions of the Trapezoidal Formulation

Many assumptions were made to keep the problem tractable and yet have an adequate approximation. The assumptions are noted and described below.

1. When solving for peaking capability, the Trapezoidal Approximation acknowledges two basic types of projects; the reservoir and the pondage project. Reservoirs have sufficient hourly regulating capability that the diurnal shape of upstream releases can be ignored. This does not preclude the project from having to meet any other restrictions, it just removes the requirement to account for inflow shape and reservoir size. The working definition of a reservoir will be a project whose usable storage exceeds 500,000 acre-feet or 250,000 second-foot-days. Another definition might be framed in terms of storage relative to average monthly inflow. This would recognize that reservoirs can be smaller on lower-flow river sections. Pondage projects are those projects that have a limited amount of regulating capability, thus requiring the tracking of inflows and usable pond.

   Some reservoirs have elevation and therefore H/K[1] that are determined solely by the month. Others have elevations and H/Ks which are a function of system content, month, and water year. These differences in the behavior of H/K and elevation are made academic because the H/K used in the trapezoidal approximation is the one implied by the monthly regulator.

2. The various constraints placed on changes in hourly and daily outflow can be reasonably approximated by one ramp rate constraint measured in kcfs/hr.[2]

3. The monthly average HK is an acceptable approximation to the hourly HK for production costing studies.

4. The release from reservoirs has a weekday/weekend shape with the weekday release (outflow) being 106 percent of the week (month) average.

5. If the time delay from an upstream plant to a pondage plant is greater than eight (8) hours, then the upstream release is assumed to arrive flat. That is, the arriving flows lose the hourly shape but not the weekend/weekday flow shaping.

6. When calculating the peaking capability of the hydropower system, the linear program assumes each weekday to be identical. It should be noted that weekends are not addressed explicitly. By constraining weekday operations, it is assured that the required weekend operation of refilling and meeting minimum flow will be feasible; that is, restrictions on a project's operation during the week assure that its weekend requirements can be met.

Consequences of Using Regulator Input

1. 1) The regulator provides the generation of the hydropower independents and the generation of those Pacific Northwest plants that are not included in the trapezoidal approximation. In either case, for projects not explicitly modeled in the trapezoidal approximation LP the energy from these plants is totaled and 50 percent of the energy is assumed to be delivered flat with the other 50 percent being delivered in the shape of

[1] H/K is the measure of a hydropower project's power output as a function of flow through the generators. H/K is measured is MW/Kcfs.

[2] 1,000 cubic feet per second per hour.

regional load. For a 10-hour peak, with the analysis based on 1973 through 1988 regional loads, the ratio of 10-hour peak to average energy production was **1.087**.

2. Project constraints expressed as weekly averages or weekly allowable ranges are met, on average, in the monthly regulation. Thus, as long as the study concerns capacity available under "ordinary" conditions, these constraints can be ignored.

3. The regulator provides the average monthly release from the reservoirs.

4. The month average H/K is obtained from the regulator by dividing the month average megawatts by the month average of (outflow - spill).

Generator Forced Outages and Maintenance

The data for modeling maintenance is based on the 1992, 1993, and 1994 Green Book. The Northwest Power Pool provided figures for the megawatts outages on maintenance, monthly, for each of these three years. For each month the average maintenance during the two lowest and highest maintenace weeks was calculated. These two numbers, expressed as a percent of the total capacity, are used as a uniform probability distribution of the capacity out for maintenance.

The average forced outage rate (FOR) of hydropower generation units in the Pacific Northwest is 2.44 percent, according to the U.S. Army Corp of Engineers in its North American Electric Reliability Council (NERC) submittal. With the large number of units, 278, and the large span in unit sizes, 6.67 megawatts to 870 megawatts, a good approximation of the distribution of units on outage is available from the normal approximation to the binomial distribution of the average unit size and failure rate. The trapezoidal approximation accounts for unit forced outages using the following algorithm:

1. calculate the installed capacity (IC),
2. find the average (capacity weighted) FOR (AFOR),
3. approximate the outage distribution by the Normal distibution with parameters:
   E(out) = IC*(1. - Percent Capacity on Maintenance)*AFOR, and
   V(out) = E(out)*(1. - AFOR), derived from the binomial approximation,
4. calculate the 75th percentile and the 25th percentile.

This procedure results in a four-state equi-probable approximation of hydropower forced outage and maintenance. The four states can be visualized as:

High Maintenance and High Forced Outages

High Maintenance and Low Forced Outages

Low Maintenance and High Forced Outages

Low Maintenance and Low Forced Outages

Parameters used in the Trapezoidal Approximation Linear Program

1) Project Variables

T_{on} = average turbine flow during on-peak period (kcfs)

T_{off} = average turbine flow during off-peak period (kcfs)

S_{on} = average spill during on-peak period (kcfs)

S_{off} = average spill during off-peak period (kcfs)

S_0 = storage at beginning of the off-peak period (kcfs-hrs)

S_1 = storage at beginning of ramp up period (kcfs-hrs)

S_2 = storage at end of ramp down period (kcfs-hrs)

2) Project Constants (most vary by month)

Q_{min} = minimum instantaneous total flow (kcfs)

Q_{max} = maximum instantaneous total flow (kcfs)

T_{max} = maximum instantaneous turbine flow (kcfs)

S_{min} = minimum instantaneous spill (kcfs)

Q_{avg} = average flows from ISAAC or SAM (kcfs)

***** RR = ramp rate limit (kcfs/HR)

NOTE: RR should be set as the most restrictive, or maybe most representative, of the limits imposed by either forebay change, tail water change, or flow change.

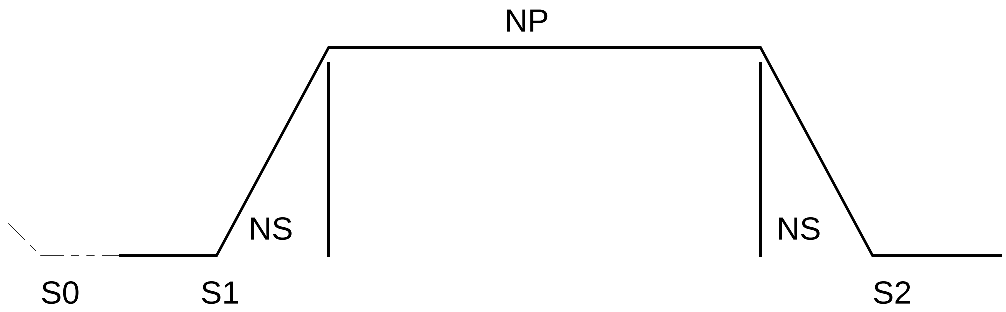
***** PS = maximum usable storage (kcfs-hrs)

SF = average side flows from ISAAC or SAM (kcfs)

HK = production coefficient (mw/kcfs)

***constant over all months**

3) Load Variables



NP = number of peak hours

NS = number of shoulder hours

NOFF = number of off peak hours

NOTE: NP + 2*NS + NOFF = 24

NOTE: See page H2-12 for the description of other time variables used in the formulation.

Linear Programming Formulation

1) Objective Function

Maximize the on-peak generation while minimizing spill. That is:

max $\sum HK*T_{on} - 100 * \sum (S_{on} + S_{off})$.

NOTE: Including $-100 * \sum (S_{on} + S_{off})$ in the objective function serves two purposes. It forces the linear program to drive spills at the individual projects toward the minimum requirement. Also, because 100 is much greater than any H/K, it prevents spilling at upstream plant(s) to benefit the peaking capability of downstream plant(s).

2) Constraints on Reservoirs in the Linear Program

a) minimum instantaneous total flow constraints

$T_{on} + S_{on} => Q_{min}$ (kcfs)

$T_{off} + S_{off} => Q_{min}$ (kcfs)

b) maximum instantaneous total flow constraints

$T_{on} + S_{on} <= Q_{max}$ (kcfs)

$T_{off} + S_{off} <= Q_{max}$ (kcfs)

c) maximum instantaneous turbine flow constraints

$T_{on} <= T_{max}$ (kcfs)

$T_{off} <= T_{max}$ (kcfs)

NOTE: Page H2-10 contains a table of H/K versus full-gate flows for all the plants. Because the regulator provides the H/K for the period being studied, the Trapezoidal Approximation can calculate the full gate flow Q_{max}. Thus this constraint accounts for both the installed capacity and the forebay elevation.

d) minimum instantaneous spill constraints

$S_{on} => S_{min}$ (kcfs)

$S_{off} => S_{min}$ (kcfs)

e) ramp rate constraint

$T_{on} + S_{on} <= T_{off} + S_{off} + NS*RR$ (kcfs)

f) average flow released from project equals regulator release

$(T_{on}+S_{on})*(NP+NS) + (T_{off}+S_{off})*(NOFF+NS) = Q_{avg}*24 *1.06$ (kcfs-hrs)

NOTE: Unique to reservoirs is a constraint stating that the average flow released from a project must match the ISAAC or SAM dispatch. This constraint reads that what is released during the weekdays must equal 106 percent of the monthly average flow as given by ISAAC or SAM. The purpose of taking 106 percent of monthly average is to simulate the shifting of water from the weekend into the weekdays. The 106 percent figure comes from the observation that the loads for typical weekdays are usually 106 percent of the weekly average load.

3) Constraints on Pondage Projects in the Linear Program, Time Lag (T)

For a pondage project all but one of the reservoir constraints are still required. The exceptions are:

a) average flow released from project equals regulator release constraint is replaced by a set of constraints on the use of limited pondage. These other constraints are:

b) storage constraint,

$S_0 <= PS$ (kcfs-hrs)

$S_1 <= PS$ (kcfs-hrs)

$S_2 <= PS$ (kcfs-hrs)

c) water balance equation,

NOTE: The water balance equations keep track of the arriving water, any shape it may have, and any effects due to time delay. Because of its complexity this constraint will be developed in three steps to motivate its form.

STEP 1: The basic premise driving the water balance equations is that the releases at a particular plant (Ton + Son and Tof + Sof) minus the releases of any upstream plants (Tup-on + Sup-on and Tup-of + Sup-of) must equal the side flows (SF) in both the on-peak and off-peak period. Using this basic premise, the water balance equations in their most simple form read as follows:

Noff*(Tof + Sof) - Noff*(Tup-of + Sup-of) = Noff*SF

N1*(Ton + Son) + NS*(Tof + Sof) - N1*(Tup-on + Sup-on)

- NS*(Tup-of + Sup-of) = (24 - Noff)*SF

STEP 2: As written, the above pair of water balance equations do not take into consideration the water stored in the pond nor the effects of delayed upstream inflows. If pondage is accounted for, the amount of water released during the off-peak period (Noff* (S1 - S0)) and the amount of water released during the on-peak period ((24 - Noff)* (S2 - S1) must be added to the equations.

S1 - S0 + Noff*(Tof + Sof) - Noff*(Tup-of + Sup-of) = Noff*SF

S2 - S1 + N1*(Ton + Son) + NS*(Tof + Sof) - N1*(Tup-on + Sup-on)

- NS*(Tup-of + Sup-of) = (24 - Noff)*SF

STEP 3: The above equations now account for storage, but do not consider delayed inflows. As written, the equations assume instantaneous arrival of inflows. In accounting for time delays, the proportion of the up-stream flows which falls arrive during a period other than their release, for example on-peak releases arriving off-peak must be included. The equations for calculating this flow (Tterm) can be found on page H2-12. Using the adjustments for the arrival of delayed upstream inflows, the water balance equations take the final form:

S1 - S0 +Noff*(Tof + Sof) - Tterm*(Tup-on + Sup-on)

+ (Tterm - Noff)*(Tup-off + Sup-off) = Noff*SF

S2 - S1 +N1*(Ton + Son) + NS*(Tof + Sof) + (Term - N1)*(Tup-on + Sup-on)

- (Tterm + NS)*(Tup-off + Sup-off) = (24 - Noff)*SF

d) weekday draft constraint.

$S_2 - S_0 <= (PS - (S_1 - S_0))/5$ (kcfs-hrs)

$S_2 - S_0 <= (PS - (S_0 - S_1))/5$ (kcfs-hrs)

NOTE: This constraint requires that the total **daily** drawdown (refill) can be no more than one fifth (1/5) of the maximum **weekly** drawdown (refill).

e) weekend minimum flow, weekend refill constraint.

When drafting daily, it becomes necessary at certain pondage projects to track whether the project will be able to meet its weekend minimum flow and refill requirements. To insure that the project is capable of meeting its weekend requirements, one weeks worth of releases from the up stream plant (168*Qup-out) plus one week's worth of side flows (168*SF), less what was released from the upstream plant during the five weekdays (70*Ton and 70*Son, 50*Tof and 50*Sof) plus weekday side flows (120*SF), must be enough water to meet the weekend minimum flow (48*Qmin) less what was drafted during the five weekdays (5*S2 - 5*S0). The weekend minimum flow equation is as follows:

168*(Qup-out + SF) - 70*(Tup-on + Sup-on) - 50*(Tup-of + Sup-of) -120*(SF)

>= 48*Qmin + 5*(S2 - S0)

Forced Outages and Maintenance

The file FOR.DAT contains two sections. The first section gives for each project:

- the number of installed units,
- the total megawatts installed, and
- the forced outage rate.

When significantly different capacity units are installed at the same project, units of the same size are collected separately. Noxon (NOXON) and Boundary (BOUND) are examples.

The second section of this file is the maintenance outage distribution. Maintenance is given by period and measured in percent of the installed capacity. There are two maintenance levels for each week. They represent respectively on average low-maitenance week and an average high-maintenance week.

First Section of FOR.DAT

PROJECT	UNITS	MW	FOR
H HORS	4	421.00	2.44
KERR	3	160.00	2.44
THOM F	6	40.00	2.44
NOXON 1	1	24.00	2.44
NOXON 2	4	430.00	2.44
CAB G	4	230.00	2.44
ALBENI	3	50.00	2.44
BOX C	4	80.00	2.44
BOUND 1	4	660.00	2.44
BOUND 2	2	420.00	2.44
LIBBY	5	600.00	2.44
COULEE 1	18	1929.00	2.44
COULEE 2	3	2070.00	2.44
COULEE 3	3	2415.00	2.44
CH JOE 1	16	1413.00	2.44
CH JOE 1	11	1203.00	2.44
WELLS	10	890.00	2.44
CHELAN	2	54.00	2.44
R RECH 1	7	818.00	2.44
R RECH 2	4	528.00	2.44
ROCK I 1	10	212.00	2.44
ROCK I 2	8	410.00	2.44
WANAP	10	956.00	2.44
PRIEST	10	907.00	2.44
BRNLEE 1	1	225.00	2.44
BRNLEE 2	4	450.00	2.44
OXBOW	4	220.00	2.44
HELL C	3	150.00	2.44
DWRSHK 1	2	207.00	2.44
DWRSHK 2	1	253.00	2.44
LR.GRN	6	932.00	2.44
L GOOS	6	932.00	2.44
LR MON	6	930.00	2.44
ICE H 1	3	310.50	2.44
ICE H 2	3	382.50	2.44
MCNARY	14	1127.00	2.44

J DAY	18	2795.00	2.44
RND B	3	300.00	2.44
PELTON	3	120.00	2.44
DALLES 1	14	1260.00	2.44
DALLES 2	8	792.00	2.44
BONN	18	1186.00	2.44
SWFT 1	3	268.00	2.44
SWFT 2	2	76.00	2.44
YALE	2	133.00	2.44
MERWIN	3	150.00	2.44

Second Section of FOR.DAT

PER	MAINT(LOW)	MAINT(HIGH)
1	.078	.111
2	.088	.109
3	.055	.083
4	.028	.048
5	.023	.027
6	.034	.044
7	.052	.063
8	.037	.081
9	.037	.081
10	.064	.080
11	.056	.069
12	.062	.088
13	.078	.108
14	.078	.108

Definition of the Hydropower System

The file SYSTEM.DEF contains two sections. The first section gives for each project:

- the immediate downstream project,

- a flag indicating whether this project is included in the study (1) or not (0),

- the time lag (hrs) to the downstream plant, not given for downstream reservoirs, any ramp rate limit (kkcfs/hr), a (-1.) indicates no constraint,

- the storage available for daily fluctuation, (-1.0) indicates a reservoir,

- the installed capacity (mw).

The second section of this file is a linear interpolation table for full gate flow versus HK. Projects that have the HK entry 0 are assumed to have constant fullgate flow as shown.

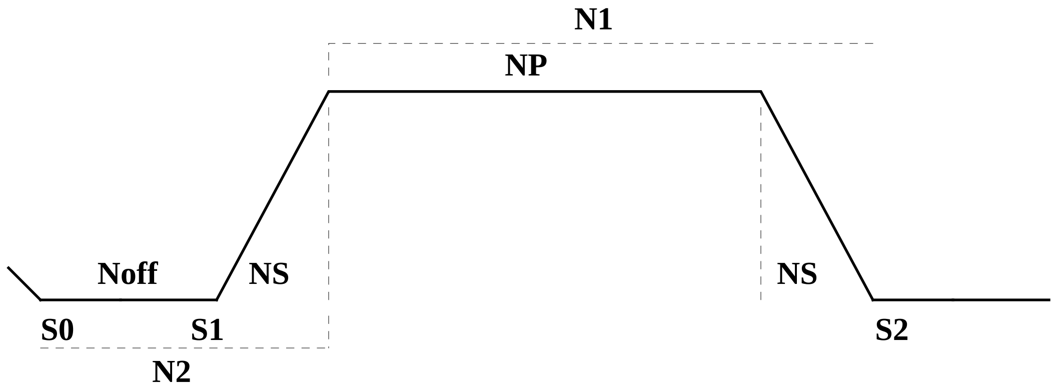
First Section of SYSTEM.DEF

Project	Downstr	Inc	Lag	RR	Pond	Cap
H HORS	KERR	1		-1.	-1.0	421
KERR	THOM F	1	31.	-1.	-1.0	160
THOM F	NOXON	1	.5	-1.	181.0	40
NOXON	CAB G	1	.5	-1.	155.1	554
CAB G	ALBENI	1		-1.	517.5	230
ALBENI	BOX C	1	1.	0.	-1.0	50
BOX C	BOUND	1	1.	-1.	84.0	230
BOUND	COULEE	1		-1.	337.5	1080
LIBBY	COULEE	1		-1.	-1.0	600
COULEE	CH JOE	1	3.	21.4	-1.0	6414
CH JOE	WELLS	1	2.	-1.	540.0	2616
WELLS	R RECH	1	5.	-1.	1186.0	890
CHELAN	R RECH	1	1.	-1.	-1.0	54
R RECH	ROCK I	1	1.	-1.	435.6	1346
ROCK I	WANAP	1	1.	-1.	133.2	622
WANAP	PRIEST	1	1.	-1.	1948.0	956
PRIEST	MCNARY	1	11.	-1.	537.6	907
BRNLEE	OXBOW	1	1.	-1.	-1.0	675
OXBOW	HELL C	1	1.	-1.	133.1	206
HELL C	LR.GRN	1	24.	2.	278.3	450
DWRSHK	LR.GRN	1	12.	-1.	-1.0	450
LR.GRN	L GOOS	1	1.	70.	270.0	930
L GOOS	LR MON	1	1.	70.	300.0	928
LR MON	ICE H	1	1.	70.	208.0	922
ICE H	MCNARY	1	1.	20.	240.0	693
MCNARY	J DAY	1	3.	150.	2239.2	1127
J DAY	DALLES	1	1.	200.	2400.0	2484
RND B	PELTON	1	1.	-1.	-1.0	300
PELTON	DALLES	1	18.	-1.	46.0	120
DALLES	BONN	1	2.	150.	635.0	2050
BONN		1		16.7	1716.0	1186
SWFT 1	SWFT 2	1	1.	-1.	-1.0	268
SWFT 2	YALE	1	1.	-1.	0.0	76
YALE	MERWIN	1	1.	-1.	2294.4	133
MERWIN		1		-1.	2200.8	149

Second Section of SYSTEM.DEF

Project	HK	FG	HK	FG	HK	FG	HK	FG
H HORS	34.85	12.08	32.25	11.62	28.51	11.46	17.15	7.72
KERR	14.12	11.33	13.36	11.41	13.10	11.30	12.13	11.79
THOM F	0.00	11.00						
NOXON	11.48	48.25	10.50	46.98	8.57	43.59		
CAB G	0.0	35.70						
ALBENI	1.88	26.66	1.46	25.55	1.19	23.88	0.96	22.04
BOX C	0.0	29.						
BOUND	0.0	53.						
LIBBY	25.07	23.93	20.37	27.78	9.97	12.77	9.33	12.29
COULEE	23.09	277.76	22.03	282.85	17.96	257.34	16.62	250.02
CH JOE	0.0	215.						
WELLS	0.0	220.						
CHELAN	26.15	2.06	25.37	2.05	24.28	2.03		
R RECH	0.0	220.						
ROCK I	0.0	220.						
WANAP	0.0	178.						
PRIEST	0.0	187.						
BRNLEE	16.88	39.98	15.50	40.16	12.70	38.74	11.50	37.57
OXBOW	0.0	25.						
HELL C	0.0	30.						
DWRSHK	47.99	9.37	41.51	10.72	40.51	10.79	34.43	10.37
LR.GRN	7.18	129.51	5.98	143.13	3.84	131.85	2.75	105.75
L GOOS	7.01	132.32	5.99	143.14	4.22	138.00	2.62	101.74
LR MON	6.92	133.42	6.02	142.39	4.38	139.82	2.66	102.53
ICE H	5.71	121.40	5.11	110.29	3.86	103.02	3.15	101.45
MCNARY	0.0	232.						
J DAY	6.72	369.68	6.62	374.34				
RND B	24.45	12.25	20.04	10.56				
PELTON	0.0	11.2						
DALLES	0.0	375.						
BONN	0.0	288.						
SWFT 1	29.40	9.12	26.49	8.62	23.00	7.80	20.19	6.93
SWFT 2	0.0	7.92						
YALE	18.15	7.33	16.99	7.05	16.10	6.87	14.53	6.47
MERWIN	13.90	10.66	13.31	10.31	11.76	9.59		

Description of the Trapezoid



NP = number of peak hours

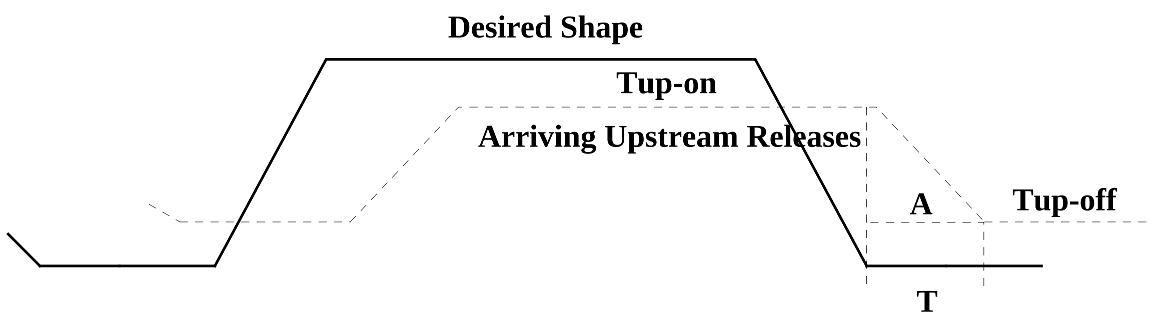
NS = number of shoulder hours, equal shoulders in morning and evening

N1 = NP + NS (Total on-peak time)

N2 = 24 - N1 (Total off-peak time)

Noff = 24 - NP - 2*NS (night time hours)

NOTE: N1, N2 and Noff are constants that facilitate the formulation of the linear program.



In this diagram, the desired shape and the arriving upstream releases are graphed as a function of time. Given time "T," storage available at the project can only be used to increase the on-peak flows to the extent that it exceeds the area "A." If the storage capability of the project is less than "A," then the extended peaking capability of the project must be reduced. The energy reduction in the on-peak period is given by:

A = Fdif*Tterm (KCFS-HRS)
where Fdif = Tup-on + Sup-on - Tup-of - Sup-of
and;
Tterm = T*T/2/NS for 0 <= T <= NS
Tterm = T - NS/2 for NS <= T <= Noff
Tterm = T - NS/2 - (T - Noff)^2/2/NS for Noff <= T <= N2
Tterm = Noff for N2 <= T <= 12
NOTE: For time delays greater than eight hours, the shape of the arriving upstream flows is thought to be lost and thusly arrives flat.

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