APPENDIX B
DOCUMENT AND METHODOLOGY REVIEW

B.1 INTRODUCTION

This appendix contains a review of resource planning tools, models, methodologies, and relevant background information, including recent resource planning studies utilizing these planning tools. Recent modeling efforts completed by and for Western and Reclamation were reviewed, as were methodologies and models in current use and commonly accepted within the electric utility industry. Pertinent integrated resource plans (IRPs) completed by utilities within the Western region were also reviewed, primarily for modeling methodologies and tools, and secondarily for information provided on other topics relevant to the Replacement Resources Process.

Many reports, articles, studies, and analyses were reviewed as part of the background research for this report. In addition, comparative reviews and analyses of resource planning tools conducted by others were utilized. A listing of the primary reference documents for this study is included in Appendix C to this report. The summary comments provided below represent a limited discussion of the area of resource planning techniques and tools, focusing on the models which were determined to be most likely candidates for use by Western, and the principal resource planning documents reviewed.

B.2 GLEN CANYON DAM STUDIES

A summary of the power modeling techniques used in the most recent planning efforts in support of environmental studies on GCD is provided below. The two studies discussed are Western's *Salt Lake City Area Integrated Projects Electric Power Marketing Environmental Impact Statement* (EPM-EIS), and the *Operation of Glen Canyon Dam, Final Environmental Impact Statement* (GCD-EIS) by the Bureau of Reclamation.

B.2.1 WESTERN SLCA/IP ELECTRIC POWER MARKETING EIS

Argonne National Laboratory (Argonne) prepared the analysis for the EPM-EIS primarily by using existing modeling tools which were customized, as required, to model the specific issues related to the analysis. Individual descriptions of the models used are provided below under the heading Models and Analytical Tools.

The utility systems that Argonne modeled encompassed all of Western's long-term firm customers, plus five large investor-owned utilities that are interconnected to Western's long-term firm customers and purchase a significant amount of non-firm energy from Western. To simplify the modeling requirements, only the five investor-owned utilities and Western's 12 largest long-term firm customers, which account for more than 85% of Western's total load, were modeled in detail. Western's remaining smaller customers were represented through a process of scaling the information for the large customers.

The power output from the Colorado River Storage Project was projected using Reclamation's Colorado River Simulation model (CRSS) and Western's geometric algorithm. CRSS was used to estimate the monthly maximum capacity and energy for each hydroelectric facility, and the geometric algorithm was then used to refine these estimates to account for hourly and daily ramp rates. The model used 85 traces (sequences of historical water conditions) to develop monthly capacity and energy probability distributions.

The monthly capacity and energy for the Collbran and Rio Grande projects were estimated based on an average of historical data. This treatment of the smaller projects did not account for changes in future generation levels; however, Argonne determined that since the two projects represent only 3% of the total SLCA/IP resources, the errors introduced from this methodology would be relatively small.

Argonne modeled Western's long-term firm energy and capacity purchase requirements, which Western uses to supplement its hydroelectric generation, with two relatively simple equations. These equations balance

Western’s load and control area obligations with Western’s resources, adjusting appropriately for project use and losses. Argonne noted that this simplified methodology may result in an apparent mismatch between capacity and energy purchases; however, they felt that the additional time and effort required to enhance the modeling would not result in significantly different conclusions for the analysis.

When Western’s projected power supply resources significantly exceed its load obligations, Western markets the surplus through short-term (seasonal or monthly) firm capacity and energy sales. Based on a review of Western’s historical marketing of short-term firm sales, Argonne decided to model only short-term firm energy sales (i.e., not include short-term firm capacity sales), and assign the short-term energy sales to Western’s customers based on each customer’s allocation of long-term firm energy.

Argonne modeled Western’s spot-market activities using both the Hydro LP model and the Spot-Market Network model. The Spot-Market Network model represented Western’s sales-for-resale activities. The Hydro LP was then used to model Western’s activity in the spot-market, including shifting off-peak hydroelectric energy to on-peak periods, based on marginal cost curves derived using ICARUS.

To evaluate the impact of the power marketing alternatives, Argonne prepared least-cost expansion plans for each of the 12 large long-term firm customers and the five selected investor-owned utilities, using Argonne’s PACE series of models.

B.2.2 GLEN CANYON DAM EIS

The EGEAS model developed by EPRI was the principal tool used to simulate operations of the regional interconnected power system, and to quantify the impacts of operational changes at GCD, in the GCD-EIS prepared by Reclamation. The EGEAS model is discussed in more detail later in this section.

The base case alternative to which all other alternatives were compared represented utilities’ operations and expansion over time, with GCD operating under average conditions just prior to the adoption of the interim flow regulations (according to the post-89 marketing criteria). The change cases examined changes in operating criteria that affect GCD's ability to generate power, including the preferred (modified low fluctuating flow) alternative. The SLCA/IP marketable resource is different for each alternative, as resource-based marketing is assumed. The study period encompassed a 50 year time frame commencing in 1991. The year 1991 was used instead of 1995 to be consistent with other analyses in the GCD-EIS.

The study area encompassed essentially the entire regional power market receiving GCD power from the SLCA/IP. Utility systems were analyzed in two categories:

- Large systems, which represent about one-half of the SLCA/IP power market, were analyzed using EGEAS.
- Small systems, many of which do not own generation resources, were analyzed using a simple spreadsheet model that assumed the costs of purchasing replacement power would be the rate of the current wholesale supplier, or the avoided costs of the selling utility.

The Environmental Defense Fund's Electric Utility Financial and Production Costs Model (Elfin) was also used to verify the production cost and economic dispatch results from the EGEAS model.

B.3 Models and Analytical Tools

B.3.1 SCREENING TOOLS

Screening tools are used in the resource evaluation process to reduce the number of alternatives to be examined in a detailed evaluation. There are several methodologies and techniques available to develop screening tools. The Electric Power Research Institute (EPRI) identifies the most common screening technique as the levelized busbar revenue requirement method.[1] The Northwest Public Power Council also uses levelized costs, based on a resource's

[1] EPRI Technical Assessment Guide, Volume 1:Rev 6, September 1989.

capital and operating costs, as a preliminary screening tool.[2]

The development of levelized busbar costs for a resource involves calculating the annual revenue requirement over the period[3], producing an equivalent annual stream of costs, and dividing the costs by the energy to determine a levelized busbar cost.[4] This information can then be used to develop a screening tool, which would consist of a table that ranks the alternatives based on the levelized busbar costs. This technique does not consider the affects of variations in capacity factor on cost. To account for alternative capacity factors, the process can be repeated for different capacity factors. The results can then be used to develop a screening diagram, or graph, that identifies the levelized cost as a function of capacity factor. Resource options that have a higher cost under all capacity factors can then be screened out (assuming for this example that cost is the sole screening criteria). The analysis can be further expanded to include consideration of other input variables which affect cost, such as alternative fuel price projections.

Additionally, evaluation criteria specific to the analysis being conducted can be developed and then used as a screening tool. Resource alternatives that do not meet the evaluation criteria would be eliminated from further evaluation. For example, if an evaluation criteria is "select only mature technologies", a resource option that is a developing technology would be eliminated from further analysis.

There are several techniques available to develop screening tools and the selection of the approach depends on the

---

2 1991 Northwest Conservation and Electric Power Plan, Volume II - Part II.

3 The period can be set at the book life of the resource. Alternatively, a set period can be defined for an analysis to ensure that the resources are evaluated over similar periods. This may require replacing a resource with a shorter life or accounting for end-effects if the resource life extends beyond the defined period.

4 Levelizing costs is a process that converts a non-uniform series of costs into a uniform series of costs that has the same present value as the original stream of costs. The levelized cost of a $10 payment that remains constant each year is $10. The levelized cost of a payment that begins at $10 but escalates at 5 percent per year thereafter is $17.27 over a 40-year period, assuming a 7% discount rate.

particular evaluation; however, it is critical that a consistent approach is adopted and applied to each resource.

B.3.2 HYDROLOGY MODELS

B.3.2.1 COLORADO RIVER SIMULATION MODEL (CRSS)

The CRSS is a series of computer programs and databases developed by Reclamation to simulate the operation and hydrology of the Colorado River system. It is used for long-term planning and operational studies by water resource managers. It can be used to evaluate such issues as flood control, irrigation, municipal and industrial water use, hydroelectric capacity and energy, water quality (salinity), recreation, and fish and wildlife under a variety of hydrologic conditions.

Development of the CRSS began in 1970; after 10 years of development and initial testing the CRSS began receiving widespread use and acceptance in the early 1980's. It is currently the standard model used by Reclamation to plan its operation of the system, and is used by Reclamation to prepare the Annual Operating Plan for the Colorado River reservoirs.

The CRSS is a monthly average water accounting model which originally ran only on a mainframe computer, but there is now a PC version of the model available. The CRSS uses initial reservoir conditions; anticipated water depletions due to municipal, industrial, and irrigation usage; scheduled generator outages; and historical hydrology to project monthly reservoir water releases, reservoir elevation levels, salinity, maximum hydroelectric generating capacity, and hydroelectric energy generation. The model also incorporates all the relevant " laws of the river" and compacts that govern the operation of the Colorado River system. These include the Colorado River Compact, Upper Basin Colorado River Compact, and the Mexican Water Treaty.

The CRSS is the most comprehensive and accepted system model for projecting reservoir water releases on a monthly basis. Its current ability to accurately project hydroelectric generation is more approximate. Generation is based on the total reservoir release for the month and the average monthly generating head, while generating efficiency is based on average monthly hydroelectric equipment efficiencies. The generating capacity estimate is the instantaneous maximum generating capability based on the average monthly reservoir head. Head losses are also based on average conditions.

The model does not currently simulate the effects of daily and hourly operating restrictions such as minimum releases and generating ramp rates on power generation. The effects of these restrictions could be approximated by modifying the CRSS to incorporate algorithms such as the geometric algorithm (discussed below). The effects would, however, still be approximate since the CRSS does not perform any hydroelectric power dispatch simulation to projected load curves.

The CRSS is typically run by Reclamation using a series of hydrologic traces to represent differing potential future runoff conditions over the planning horizon. Reclamation has standardized a method called the index sequential index method for generating the hydrologic traces based on the historic hydrologic sequence. A lag of one year is typically used for wrapping to the end of the historic sequence of years.

The CRSS is considered to be the "standard" Colorado River Model. It is well documented and tested. It is also the official planning model used by Reclamation and other entities.

B.3.2.2 PRYSM

PRYSM is a new hydrologic model being developed by the CADSWES of the University of Colorado at Boulder. A version of this model is being developed for Reclamation. It appears that the model will primarily be a water routing model with limited hydroelectric generation and dispatch modeling abilities. Eventually, this model may be used by Reclamation as a replacement for the CRSS.

B.3.3 HYDROELECTRIC GENERATION DISPATCH

B.3.3.1 VALORAGUA

VALORAGUA is a model for the optimal operating strategy of mixed hydro-thermal generating systems developed by the

International Atomic Energy Agency in 1992. It was developed for the Electricidade de Portugal (EDP) primarily for planning of EDP's power generating system. The goal of VALORAGUA is to determine the optimal operational strategy for a fixed power system configuration, taking into account the most important constraints and uncertainties that characterize the operation of a hydro-thermal system. The model is a monthly model and determines the value of water in terms of energy value. The model is only designed to optimize the current power system operation and not future investments in power generation. The model optimizes water releases over a year using input and output of the hydroelectric generating units in the system, taking into account the costs of operating the thermal power system.

B.3.3.2 HYDRO LP

Argonne developed and used Hydro LP for the EPM-EIS to simulate the ability of Western's SLCA/IP hydroelectric generation facilities to serve firm and project use loads and estimate Western's participation in the spot-market. The model is a custom model developed for Western. It incorporates spot-market prices determined by the Spot-Market Network Model discussed below. Microsoft FoxPro is used as the primary programming tool; the model also includes custom C-code and requires Industrial Strength LINDO as its linear optimization package.

The Hydro LP model is designed to minimize Western's net operating costs considering spot-market purchases, supply source energy costs, and revenues from spot-market sales. Hydro LP incorporates the discharge restrictions placed on GCD. Operational restrictions include minimum and maximum discharge restrictions, and hourly and daily ramp rate restrictions at GCD and Flaming Gorge. Hydro LP also includes a minimum transaction margin that is required for shifting hydroelectric generation between on and off-peak periods, area load control services, and IPP spinning reserve requirements.

Hydro LP is a model for simulating short-term operations. It runs on a weekly basis to estimate hydroelectric generation operations and imports spot-market activities for each hour of the week from the SMN model. Because of ramp rate restrictions and monthly mandated water releases at each dam which are determined externally by the CRSS model, each hour of the simulated week depends on all other hours in the week. Monthly results are extrapolated based on one simulated week per month.

Required input data for Hydro LP includes:

- Hourly long-term firm and short-term firm demand to be met by the SLCA/IP hydroelectric generation system
- Operational restrictions imposed at each dam and on Crystal Reservoir
- Monthly water releases at each dam and an associated power conversion factor
- Side flows into the hydrologic network
- Inland Power Pool (IPP) reserve requirements
- Area load control requirements
- Hourly spot-market price estimates for the week (from SMN model)
- Variable operation and maintenance costs for each hydroelectric facility
- Hydroelectric generation shifting price margin

Model output includes:

- Hourly operations at each dam including discharge, reservoir level, and generation
- Purchased power costs
- Sales revenue
- Spot-market hourly purchases
- Spot-market hourly sales

B.3.3.3 WATERWAY

WaterWay is a generalized, short-term hydroelectric simulation and optimization model designed to represent the hourly operation of a network of hydroelectric stations. The model is commercially available from The Simulation Group (TSG), and can be integrated into the use of TSG's production-costing models, which use the same input format and grammar, MULTISYM and PROSYM. WaterWay allows the modeler to represent the engineering level detail of a hydroelectric system; this allows for accurate simulation of the hourly operations. The model uses an hourly time step but can model multi-year operations. Hydroelectric generation is optimized over 168-hour weeks. The model is designed to handle large problems. It is driven strictly by user input.

WaterWay is designed to run in either a stand-alone mode or in conjunction with MULTISYM/PROSYM. When used in conjunction with the production-costing model, WaterWay allows detailed simulation of a hydro-thermal power system. In the integrated mode of operation, WaterWay’s optimization routine will maximize the economic benefits of hydroelectric production. This can be accomplished by using either the electric system load or the electric system incremental cost as the optimization target. When the load is used as the optimization target, a peak-shaving solution is obtained. When the incremental cost is used as the target, the optimization considers time-of-day, hydroelectric generation, and thermal system unit commitment costs. In stand-alone mode, the optimization target is the time differentiated generation values, that is, static price signals that vary by time of day.

The following details of the hydroelectric system can be specified:

- hourly level operation
- cascaded and branched projects
- time delays in water travel down river reaches
- up to 30 storage reservoirs
- evaporation
- seepage from impoundments
- time varying release requirements
- natural inflows from up to 30 gages
- multiple operating modes for storage facilities
- multiple types of ramp rate constraints

- multi-point turbine efficiency curves
- multi-point head loss functions
- minimum turbine operating requirements
- flexible tailwater representation
- pump-back facilities

Since WaterWay operates on a weekly optimization basis, it currently has no way to automatically look back and adjust constraints based on past operating results. When an entire hydroelectric generating station is being simulated as a single node, WaterWay combines the individual turbine-generator units and treats them as one via the composite efficiency function. Individual penstocks are also treated as being combined. For multiple penstocks, the head loss function needs to be formulated to represent the combined losses of a multiple penstock system.

Variables within WaterWay that constrain hydroelectric operations can be varied by the user on an hourly basis. These include river releases, diversions, control settings, and inflows to the reservoirs. Power generation is calculated hourly. WaterWay allows the user to simulate the operation of each reservoir within the system in one of five different modes. These modes include 1) using set releases or storage elevation control functions, 2) flow-optimized mode where elevation effects are not significant, 3) flow and head optimized when elevation changes within a week are significant, 4) unit commitment where units are cycled to make best use of available water, and 5) mixed optimized and non-optimized nodes within the reservoir network.

In the set release mode, the user can specify the release pattern along with the storage operating constraints and the discharge constraints. WaterWay performs unit commitment respecting the constraints imposed on the node.

In the storage elevation control modes, WaterWay operates the reservoir to stay within the user-specified elevation/storage constraint and other operating constraints. This mode is used for automatic peaking operation.

In WaterWay, flow releases are optimized using convex cost, network flow programming to non-linear optimization targets. Unit commitment is performed using incremental dynamic programming on a node-by-node basis. Discharges affected by enforcement of operating constraints are rescheduled using the network flow programming routine. Full detailed power calculations are made on an hour-by-hour basis.

B.3.3.4 Hydroelectric Load/Dispatch Tools

Environmental Defense Fund Hydroelectric Peak Shaving Model

This model simulates the dispatch of a single hydroelectric station considering hourly operating restrictions. Dispatch is based on the assumption that hydroelectric generation is most valuable during periods when the loads are highest, and thus the shape generated is load dependent. Within the constraints related to water availability, available reservoir storage, and operating constraints such as ramp rates and minimum generation levels, the model dispatches the hydroelectric generation to minimize peak load.

Western’s Geometric/Trapezoidal Model

The CRSS model provides information on a monthly level. The algorithm is a simple approximation to an hourly dispatch model and could be incorporated into a variety of models. It does not include any actual generation dispatch against system load curves. The geometric algorithm is strictly an algorithm for approximating hydroelectric generation and is not a simulation model, but merely a geometric approximation of dam performance, given operational restrictions and an assumed daily peak load duration.

For the EPM-EIS, the monthly capacity and energy information was further refined to account for operational constraints such as hourly and daily up and down ramp rates, minimum and maximum discharges, and maximum daily discharge fluctuations. A trapezoidal/geometric algorithm was used to estimate the maximum generation level that can be achieved for a specified time for each peak day in a month based on the discharge restrictions at a particular dam. The algorithm recognizes weekend off-peak periods and accounts for the total monthly generation. The geometric algorithm uses a rectangle to represent the minimum flow requirement and a trapezoid to represent the amount of energy that can be used for peak-load shaving. For the EPM-EIS, it was assumed that peak generation levels were to be maintained for four hours during the time of system peak load.

B.3.4 ELECTRIC PRODUCTION COST/ECONOMIC DISPATCH

B.3.4.1 MULTISYM

MULTISYM is a chronological production costing simulation model designed specifically for modeling multiple-areas including power pools, dispersed multi-utility operations, shared transmission lines, and exchange contracts with transmission limits. MULTISYM is a commercially available model developed and supported by the Simulation Group.[5] The CRSP CSO of Western currently is a licensed user of MULTISYM.

The basic time-unit in MULTISYM is one hour. The Loadfarm module of MULTISYM is used to generate hourly loads for the projected period based on representative historical hourly loads, and a projection of capacity and energy.

The chronological nature of MULTISYM allows for modeling almost all types of technologies, and allows for the explicit consideration of ramp rates and other time-dependent parameters. Several types of purchases and sales can be modeled including firm, non-firm, variable, and fixed. Resources can be defined with up to five capacity blocks. The "existence logic" included in the model provides the capability to link jointly owned units, and to accurately model the heat-rate curve of all generating units, including separate operating configurations for combined-cycle units. The hydroelectric resource dispatching capabilities of MULTISYM are enhanced through integrating the model with the WaterWay model discussed above.

[5] MULTISYM is an expanded version of PROSYM which was also developed by The Simulation Group/Henwood Energy Services.

Maintenance schedules can be entered for each resource. Alternatively, the distributed maintenance scheduling option, which attempts to levelize the loss of load probability, can be used. Forced outages are represented with the Monte Carlo method which includes random draws from a probability distribution. Units can be forced out from one hour to one week.

The loads and resources are assigned to transmission areas which are connected via explicitly-defined links. These transmission areas can represent different utility systems or sub-sections of a single utility. Transmission line losses, capacity constraints, and wheeling charges can be defined for each direction of the transmission links. Transmission line outages can be represented using the “existence logic” provided in the model. Both primary and secondary spinning reserve can be defined for a transmission area. Additionally, the transmission areas can be assigned to control areas to honor control area spinning reserve requirements.

B.3.4.2 Production and Capacity Expansion (PACE)

Argonne developed the PACE expansion planning system which consists of a series of models including the production costing module ICARUS and the expansion planning module BUILD. The annual costs for alternative inventories of units are developed in the ICARUS module. The BUILD module then compiles “snapshots” of the results from ICARUS to determine the lowest cost expansion plan. The PACE system of models is a proprietary product of Argonne.

B.3.4.3 Spot-Market Network Model (SMN)

The SMN model is linear program, developed by Argonne, that simulates the non-firm energy transactions over a transmission network. The SMN model uses a network of nodes connected by links to represent the spot-market system. The nodes represent loads, generating resources, and distribution substations; and the links represent the transmission paths connecting nodes. The objective function for the linear program is to minimize the production costs for the network including supply costs, wheeling costs, and profit margins.

The type of nodes include variable-supply/fixed-demand, fixed-supply/demand, and sub-station. The variable-supply/fixed-demand node represents a single generating resource or a group of interconnected units. The demand at the node can be zero or set equal to the load used in the ICARUS and PACE modules. The generating resources are represented as piece-wise linear marginal cost curves. The curves can be developed by the user, if the node represents a single generating unit, or the APEX model of the ICARUS production costing model can be used to generate cost curves representing a system. The effects of forced outages can be included through the cost curve developed by APEX. Alternatively, the capacity of the generating unit can be derated.

Fixed-supply/demand nodes represent fixed generating units with fixed local demands. The sub-station nodes are used to reroute power flow. The total power flow entering a substation node must equal the total power flow exiting the node.

Transmission lines are represented as links which can include associated wheeling costs, losses, transmission constraints, and line rights. The maximum transfer is based on the net transfer, i.e., the schedule in one direction can exceed the maximum capacity if an opposite schedule, or back-schedule, occurs at the same time.

A value is defined at each node to represent the minimum profit margin that a supply source must receive before it will sell to the grid.

B.3.4.4 ICARUS

The ICARUS module is a production costing model that estimates system costs, generation by unit, and system reliability, and is also a proprietary product of Argonne. ICARUS is a probabilistic algorithm that uses load duration curves to estimate block-level capacity factors. Each load duration curve is represented by forty-two data points. Load duration curves can be developed for different periods, for the EPM-EIS, load duration curves were developed for 26 periods for each year.

Power supply resources can be modeled in ICARUS with a maximum of two capacity blocks, a base block and a peak block. These resources can be thermal generating units as well as purchases between utilities. To model jointly owned units, the unit is split into two or more units based on ownership fractions. The user then models the physical characteristics of these jointly owned units, i.e., equivalent forced outage rate and heat rate curves, on a consistent basis. The operating and maintenance costs and the fuel cost characteristics can be entered separately for each owner.

The maintenance schedule for units can be specified completely by the user, partially by the user, or completely determined by the model. With the 26 period definition used in the EPM-EIS, if a unit is out any portion of the two-week period it is out the entire period. Therefore, units requiring three weeks of maintenance would be out for four weeks. (In the EPM-EIS, Argonne adjusted for this by alternating the maintenance schedule of any unit with an odd number of outage weeks by scheduling the maintenance for one year one-week short and the next year one-week long.) To determine the schedule of maintenance for units without a fixed maintenance schedule, the model uses the expected reserve margin to evaluate the effect of the maintenance schedule on the system and schedules maintenance to minimize this effect.

The generating dispatch logic used in ICARUS is based on the Balaeriaux-Booth method in which the effect of unit forced outages are represented by additional load that must be served by other units creating an equivalent load curve. This process of convolving each unit into the equivalent load curve provides estimates of system reliability parameters including loss-of-load probability, expected unserved energy, and loss-of-energy probability.

The order in which units are loaded is based on the user defined order, economics, or spinning reserves. A unit is assumed to contribute to spinning reserve only when it is loaded at a capacity level equal to its first block.

The capacity of energy limited resources, hydroelectric generation, or limited contracts, is represented with a base or run-of-river portion and a peak portion. The peak portion is then loaded to meet the specified energy generation in the period.

B.3.4.5 ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM (EGEAS)

The EGEAS model was developed by Electric Power Research Institute (EPRI) to evaluate expansion planning alternatives for a single electric utility or a pool of utilities. The model includes optimization, production costing, and reliability analysis. Additionally, the model provides five capacity expansion options ranging from a basic screening analysis to a detailed dynamic programming algorithm. The EGEAS model is a proprietary model of EPRI, although it can be licensed by others through arrangements with EPRI.

The EGEAS model contains a pre-processor that converts hourly loads to load duration curves for a year, which can be further refined to seasons and sub-seasons. This preprocessor also shapes the generation from non-dispatchable resources to the appropriate time-period.

EGEAS is capable of modeling several types of technologies. Each resource can be defined with up to five capacity blocks. The maintenance schedule for a resource is defined in terms of weeks per year. Forced outage rates can be defined for the unit or for each block of capacity. Four different reliability measurements are reported to evaluate system reliability; including reserve margin, loss of load probability, relative reliability, and unserved energy.

The loads and resources of a utility can be linked to other utilities to model reserve sharing and spot-market activities. The utilities are linked via defined tie-lines. Transmission constraints are modeled based on the maximum amount of energy transfer allowed across the tie-line based on the transmission capacity limit, capacity factor, and the energy in the period.

EGEAS contains four capacity analysis options, ranging from preliminary analysis tools based on screening curves to sophisticated non-linear analysis tools utilizing a generalized benders decomposition algorithm and a dynamic programming algorithm. A stand-alone, detailed probabilistic production costing algorithm is also available for production costing and reliability analysis.

B.3.5 COMBINED GENERATION AND TRANSMISSION SIMULATION

B.3.5.1 MULTI-AREA PRODUCTION SIMULATION (MAPS)

The MAPS model incorporates generation and transmission system expansion planning, production costing, and marginal energy costing. The model simulates the economic operation of a power pool or coordinated group of utilities. MAPS was developed by General Electric and is primarily used to evaluate transmission expansion options. The model is currently commercially available for an annual license fee of $85,000.

Two methods are provided to simulate power exchanges among utilities. The transportation algorithm provides a less detailed approach. Alternatively, the MWFLOW module uses distribution factors, derived from an ac power flow, to monitor the flows on the key transmission lines in the system. This methodology allows simultaneous considerations of both pre- and post-contingency conditions of the transmission system, resulting in a “secure” dispatch.

The MWFLOW approach uses a transmission-constrained production simulation model. Separate dispatches of the interconnected system and individual company loads and generation can be performed to determine the economic interchange of energy between interconnected companies. Loads are modeled chronologically based on all hours in the year, and can be separated down to the individual bus level if desired. Both Monte Carlo and probabilistic simulation modes are available. Thermal generating units can also be modeled on a detailed basis.

Because of the detailed electrical representation of the transmission system in MAPS, it’s strength is modeling transmission-related configurations such as transmission access, wheeling costs, bottlenecks, and loop flow. At present, output is in binary format, requiring customized report formatting at a later date.

With regard to transmission system modeling, when a new unit is added the existing transmission system is used to transmit the power to the load centers. If an overload occurs the information can be stored and used for planning purposes, alternatively, the system can be re-dispatched to prevent overloads recording the increased production costs, and allowing loss of load.

B.3.5.2 TOPS

The **T**ransmission **O**riented **P**roduction **S**imulation (TOPS) model is a production cost modeling program under development by Power Technologies, Inc. (PTI). TOPS will be a production cost modeling program that also includes transmission system modeling capabilities, making it similar in concept to the GE MAPS program. Western and several other utilities are funding development of TOPS, and will have licenses to use the program when it is completed. Since the model is under development, and Western has a confidentiality agreement with PTI during the development phase, details of the program’s features and capabilities are not yet available. Western is currently evaluating a beta version of TOPS.

B.4 RENEWABLE RESOURCES

Renewable resources are those generating resources which utilize fuel sources which are not depleted through use (hence “renewable”). Examples are solar, wind, hydroelectric, and certain “waste-fuel” sources such as MSW and biomass. Renewable technologies have been most frequently used to date in the following circumstances:

- to increase the fuel source diversity of utilities with a large pool of generating resources;
- in situations where the alternative energy cost is high;
- in remote locations where distributed generation is required; and
- in cases where special economic incentives are offered.

With respect to the last item, the Energy Policy Act of 1992, Section 121, established a 15 mill (1.5 cents) per kilowatt-hour Renewable Energy Production Incentive (REPI) to be paid to owners or operators of renewable energy production facilities. This may be a significant aid to renewable resource development and competitiveness in the marketplace. Currently, taxable entities can claim the 1.5 cent payment as a tax credit, but funding sources for payments of the REPI to non-taxable entities are less certain at present.

B.4.1 EVALUATION OF RENEWABLE RESOURCES

In determining the suitability of a particular resource alternative to given load requirements, it is useful to consider many factors, including resource availability and cost, status of technology, environmental impacts, capital and operating cost, and implementation schedule. Pressures on the regulated utility market to keep near-term rates as low as possible implicitly defers the risk associated with uncertain future events. The difficulty of evaluating and weighing such risk factors as fuel price risk, fuel availability risk, and environmental impact risk makes technology comparisons complex, and can disadvantage renewable electric technologies.

Renewable resources have different characteristics from conventional supply-side technologies in many cases. Care must be taken to ensure that capacity, availability, location, and risk are properly accounted for when evaluating renewable resources.

As previously mentioned, resource type, location, reliability, dispatchability, environmental impact, and fuel cost and availability are all important factors to be considered in resource evaluation. Many of these factors are especially important to consider with respect to renewable resources, as their characteristics in these areas often differ greatly from those of “conventional” supply-side resources.

B.4.1.1 RESOURCE TECHNOLOGY

Resource type, for example, includes the stage of technology development, which can vary from mature to the pilot or demonstration stage for some renewables. Some renewable technologies are in a relatively early stage of commercial development compared with common fossil fuel-fired technologies, and have little operating history from which to judge commercial cost and reliability. Of course, this risk also exists with newer fossil fuel technologies such as coal gasification, and with some newer emissions control technologies used on fossil fuel-fired facilities.

In addition, the development stage can change quickly in some of the rapidly advancing areas of technology like solar, fuel cells, and wind generation. A traditional source for this type of information is EPRI's Technology Assessment Guide (TAG).

B.4.1.2 RESOURCE LOCATION

Solar, geothermal and wind resources are limited to certain well-defined geographic areas within Western’s service territory, where the energy resource (or the renewable energy “ fuel”) exists in sufficient quantities to allow cost-effective renewable resource facility development.

B.4.1.3 RESOURCE DISPATCHABILITY

The time- and climate-dependent characteristics of wind and solar energy are clear examples of the direct affect on generating unit availability and ability to serve peak loads when needed. Wind and solar energy are intermittent resources because capacity is not necessarily available at any given time. Solar energy generally peaks on summer afternoons, which is coincident with summer peaks due to air conditioning demand in the areas of the southwestern United States where insolation is highest. This is not the case for wind energy, which may be both seasonally and time-of-day dependent. Studies have been done on the correlation between wind resource and utility daily load curve. It is generally true that the better the wind resource, the higher the resource capacity factor, reducing the importance of the daily coincidence between system peak and peak wind availability.

B.4.1.4 FUEL RISK

Renewable resources generally carry lower risks than conventional fossil fuel resources with respect to fuel availability and the potential for future fuel price increases.

B.4.1.5 ENVIRONMENTAL IMPACT RISK

Also, risks associated with current and future cost and availability impacts on generating facilities associated with air quality, water quality, hazardous waste disposal and other environmental regulations can vary greatly between technologies. The difficulty from a planning and evaluation standpoint is that risks must be quantified to some extent to be incorporated into a meaningful evaluation, and this can be a difficult and somewhat subjective process.

B.5 ENERGY EFFICIENCY

Energy efficiency (“EE”), or demand-side management (DSM), entails activities which involve actions on the customer side (demand-side) of the electric meter. Activities of this type could potentially be considered a resource in the Resource Replacement Process. DSM/EE programs could reduce the need for capacity and energy, and thereby “replace” a portion of the power previously provided by GCD.

DSM/EE activities are usually either directly caused or indirectly stimulated by the actions of the utility or a particular customer. These actions can be as simple as providing information to customers on lowering energy consumption. DSM/EE involves deliberate utility intervention in the marketplace to change the configuration or magnitude of the end-use customer’s demand and energy requirements. Through DSM/EE, the utility impacts the demand of the customers, which in turn impacts the utility's load shape.

DSM/EE programs can be categorized into four general categories of activities:

- **Load management.** Shifting load from high cost on-peak periods to lower cost off-peak periods.
- **Strategic conservation.** Reducing electric usage regardless of the time period.
- **Electrification.** Replacing non-electric equipment or processes with electric uses.
- **Strategic growth.** Deliberately increasing a utility's market share.

B.5.1 CURRENT WESTERN ENERGY EFFICIENCY PROGRAMS

Western currently has several programs for increasing internal energy efficiency at its facilities, including:

- The DOE has an agency-wide goal to reduce the overall energy usage for its facilities by 20 percent (compared to 1985 usage) by 2005 in response to the EPAct. An Executive Order signed by President Clinton set a goal of saving 30 percent by 2005. As a part of achieving these goals, Western is complying with federal “Energy Star” regulations requiring the purchase of energy efficient computer equipment.
- Western has joined the EPA’s “Green Lights” program to increase lighting efficiency at Western’s facilities. Specifically, Western’s CRSP CSC had an instrumental role in a program undertaken by the building manager of Western’s leased office space in Salt Lake City. The existing office lighting was replaced with efficient fluorescent lamps, electronic ballasts, and motion sensing light switches, not just in Western’s leased space, but throughout the 13 story building.
- Western is preparing a building master plan for all Western-owned CRSP buildings (administrative buildings, substation control buildings, storage garages, warehouses, etc.). Part of the building

master plan addresses energy efficiency at each building and identifies needed efficiency improvements.

- Whenever Western designs a transmission system addition, upgrade, or replacement, energy efficiency is factored into the design. Transmission system upgrades or additions are designed with power losses in mind. Substation improvement projects considered include more efficient substation lighting, building HVAC and lighting improvements, power transformer efficiency, and station service loads. Finally, transmission line and power transformer losses are valued at the cost of new replacement generation rather than the current firm power rate.

B.5.2 EVALUATION OF ENERGY EFFICIENCY

When considering demand-side measures as a potential replacement resource, four principal areas should be considered, as follows:

- **Performance.** The DSM/EE program should influence the demand for electricity. There should be a direct action or outcome from the utility's efforts.
- **Selected objectives.** The DSM/EE program should achieve a selected objective: for example, reduce overall energy costs, reduce peak demand purchases, or improve reliability. Supply-side options usually have a stated objective, such as delivery of baseload amounts of energy, or provision of peaking power during high load periods. Demand-side resources should also have targeted objectives, such as reducing the peak demand on the system, or shifting load to lower cost periods.
- **Evaluation versus non-DSM.** The concept of demand-side management as a resource also means that it must be selected for economic reasons and compared to alternative resources, including traditional supply-side resources. The resource should be

evaluated based on its costs and benefits, and only those DSM/EE which make economic sense should be developed as a resource.

- **Response of customers.** A demand-side resource must involve desired changes of the customer's demand and must ultimately impact the utility's load shape and influence the total costs of the utility.

B.5.2.1 COST EFFECTIVENESS TESTS

There are several cost effectiveness tests available to evaluate DSM/EE programs, as described below.

- **The Utility Cost Perspective.** The utility perspective only looks at the costs that the utility incurs; consequently, it measures if a program is "good" from the utility's point of view.
- **The Participant Perspective.** From the participant's view, only their out-of-pocket expenses are considered. This test measures if the DSM/EE program is "good" for a participant. Incentives from the utility act to reduce a participant's out-of-pocket expense. Any money spent by the utility for marketing or administration is not considered in this cost-effectiveness test.
- **The Ratepayer Perspective.** Not all customers are participants in a DSM/EE program. These non-participants look at costs differently than the participants. The Ratepayer Impact Measure (RIM) test explores the costs to the ratepayers based on the impact of the DSM/EE program on the utility's revenue requirements and rates. This test measures if a program is "good" for all the ratepayers based on rate impacts.
- **Total Resource Cost Perspective.** The Total Resource Cost (TRC) Test examines the total cost of implementing the measure, without regard to who pays the cost. It does not consider rebates or other transfer payments between the utility and the entity implementing the program, but only the actual cost required to implement the program.

- **The Societal Perspective.** Some impacts from electric generation, such as unmitigated pollution, are not captured in the marketplace, yet are still costs to society. The Societal Test extends the Total Resource Cost Test, which includes all costs, from whatever perspective, to include external costs of environmental damage. Although this test is designed to measure if a DSM program is "good" for society, the subjective nature of this measurement has made it difficult to date to standardize externality costs.

B.6 Resource Expansion Plans and IRPs

The resource plans of several utilities located in the region of Western's service territory were reviewed. The primary purpose of the review was to identify the modeling methodologies, tools, and evaluation criteria used by the utilities in their resource planning.

B.6.1 SALT RIVER PROJECT
BALANCED STRATEGY REPORT, 1992 and FORECAST OF LOADS AND RESOURCES, 1994

Salt River Project (SRP) is the nation's third-largest public power utility, and Arizona's largest water supplier. SRP consists of two organizations, the Salt River Valley Water Users' Association and the Salt River Project Agricultural Improvement and Power District. SRP describes its power planning process as a " balanced strategy" that attempts to strike an effective balance between multiple, and often, competing objectives. The goals of the twenty-year plan are to:

- ensure the future adequacy and reliability of service to electric customers;
- provide for an economically efficient and environmentally responsible utilization of resources;
- maintain the financial and operational integrity of SRP; and
- minimize risks associated with planning for an uncertain future.

SRP planning horizon in its 1994 Forecast of Loads and Resources included fiscal years 1993 through 2013. In this forecast, SRP planned to meet its projected short-term load growth with purchases, and its projected long-term load growth with a total of 1188 megawatts of new resources including 900 megawatts of gas-fired resources, 50 megawatts of alternative/renewable resources, 236 megawatts of a diversity exchange, and a 2 megawatt-Watt fuel cell.

SRP uses a wide-variety of models for various planning efforts. In its next planning efforts, SRP will probably use the MIDAS model which includes decision analysis to model uncertainty. Economy energy purchases represent such a small portion of SRP's total system that they are not modeled in detail. SRP will model economy energy sales with the methodology provided in MIDAS.

B.6.2 PUBLIC SERVICE COMPANY OF COLORADO *INTEGRATED RESOURCE PLAN, 1993 and INTEGRATED RESOURCE PLAN ANNUAL PROGRESS REPORT OCTOBER*, 1994

The Public Service Company of Colorado (PSCO) is an investor-owned electric utility with a service territory that covers approximately 10% of the state of Colorado and includes 80% of the total state population. PSCO's IRP was developed to balance the following objectives:

- minimize the total resource costs;
- minimize impacts on electricity prices;
- maintain system reliability;
- minimize impacts on the environment;
- ensure flexibility for responding to future unknowns;
- maintain the financial health of the company;
- use a diverse mix of resources and technologies;
- utilize resource efficiently;
- use renewable energy sources where appropriate;
- contribute favorably to local and state economies; and
- develop a sustainable plan.

PSCO plans to meet its projected load growth with demand-side management savings of 549 megawatts (approximately 10% of total demand) and over 1500 megawatts of capacity additions including combustion turbines, coal-fired generation, repowering of an existing unit, and two small renewable energy demonstration projects; a wind project and a photovoltaic project.

PSCO used COMPASS to prepare the detailed evaluation of alternative DSM programs. An initial screening of supply-side options was prepared based on the calculated levelized ownership costs. The supply-side options were further refined with PROSCREEN. The PROVIEW/PROSCREEN models were then used to integrate and optimize the supply-side and DSM options and develop alternative plans including sensitivity analysis. MAINPLAN was used to develop the maintenance schedules for the alternative resource plans. MULTISYM was used to determine production costs and evaluate system reliability. The corporate financial model was used to determine the rate impacts of the options. The analysis resulted in a preferred plan for the 20-year planning horizon.

As part of its IRP process, PSCO issued a request for information (RFI) for generation options. The bids were first screened using a static screening analysis (i.e., levelized cost analysis). PROVIEW was then used to determine if the options reduced the cost of the base resource plan. The lowest-cost alternatives were further evaluated with PROVIEW/PROSCREEN. A system needs analysis and a feasibility analysis was prepared to determine potentially feasible options. These options were then included as part of the development of the proposed plan.

B.6.3 BONNEVILLE POWER ADMINISTRATION

1992 RESOURCE PROGRAM, 1996 INITIAL RATE PROPOSAL DIRECT TESTIMONY SPONSORING THE LOADS AND RESOURCES STUDY AND DOCUMENTATION, and 1996 INITIAL RATE PROPOSAL LOADS AND RESOURCES STUDY

BPA prepares, on a biannual basis, a plan of resource programs to meet future loads in a manner consistent with the Northwest Power Plan adopted by the Northwest Power

Planning Council. The analysis for the 1992 Resource Program was prepared using ISAAC for a 50-year study period. This information was then used to develop the ten-year resource program which consisted of cost-effective conservation, new resource acquisitions, and purchases.

The process that BPA used to develop the 1996 Load and Resource Study includes the following major steps:

- Regional load forecasts were developed
- Resources were evaluated for their expected output
- Load and resource balances were prepared for each of the major utilities in the region
- BPA's system resources were compared to firm loads to determine the Federal firm surplus or deficit

BPA developed two types of regional load forecasts (1) a "price effects" forecast that projects the loads assuming no new DSM programs, and (2) a "sales" forecast that includes both the effects future DSM programs and the estimated load that will no longer be served by BPA.

To determine the firm and non-firm hydroelectric generation, BPA used a regional hydroelectric regulation model that simulates the operation of the Pacific Northwest electric power generation system. The model includes consideration of historical stream flow record, monthly loads, thermal and other non-hydroelectric resources, hydroelectric plant data for each project, and the constraints limiting each project's operation. These constraints included the findings from the National Marine Fisheries Service's Biological Opinion, dated March 2, 1995. Incorporating the Biological Option restrictions changed the critical period from the 42-month period September 1, 1928 through February 29, 1932 to the 8-month period of historical stream flows that occurred from September 1, 1936 through April 30, 1937. This determination of a critical period that is less than one year eliminated the ability to shift firm energy between water years, which simplified the modeling process. The projection of firm and non-firm energy generation were determined directly by simulating the 1997 through 2001 levels of load and resource development with the 50-year hydroelectric regulation study, and the previous iterative process was not required.

The projection of the generation from the non-hydroelectric generating resources owned by other utilities in the Northwest was provided each utility. For each of the major utilities in the Northwest, a monthly load and resource balance was developed to determine the if the utility had sufficient firm resources to serve firm load. The firm deficits for the public utilities in the Northwest represent the firm load for BPA. Firm hydroelectric generation was then compared to the firm BPA loads to determine if BPA has sufficient firm generation to meet loads.

B.6.4 TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

***INTEGRATED RESOURCE PLAN OCTOBER 1993, and POWER REQUIREMENTS STUDY*, 1992**

Tri-State Generation and Transmission Association (Tri-State) is a member-owned generation and transmission cooperative. Tri-State provides wholesale power to its 34 members located in Colorado, Nebraska, and Wyoming. The objectives for Tri-State's IRP were to:

- Refine Tri-State's Planning Process;
- Maximize Efficient Life of Resources;
- Enhance Role as Member Planning Resource;
- Develop In-house Expertise; and
- Develop Meaningful Action Plan.

Tri-State uses the EGEAS model to perform production cost modeling and expansion planing. At the time the IRP was prepared, Tri-State had adequate power resources available to meet its obligations for the next 20 years. This IRP provides the framework for the IRP process to be used when new resources are required.

B.6.5 NEVADA POWER COMPANY
REFILED 1994 RESOURCE PLAN EXECUTIVE SUMMARY AND ACTION PLAN

Nevada Power Company (NPC) is an investor owned electric utility that serves a population of over 998,000 people in Southern Nevada. NPC's plan was developed to meet the following objectives:

- create a company-wide plan which draws upon expertise both inside and outside the company;
- implement strategies to guide resource planning efforts and decisions which comply with applicable laws and regulations, and allow flexibility and quick responses to changing conditions; and
- create a plan that is "reader friendly" and encourages understanding of the process.

NPC's service territory is experiencing significant growth due primarily to the gaming industry. NPC plans to meet approximately four percent of its projected load growth with DSM, and meet the balance of its projected requirements through purchase power.

NPC utilized a competitive bidding process for new demand-side management programs that resulted in contracts with three energy service companies to provide new services for commercial customers. Because of the current relatively low-cost surplus power available, NPC is reevaluating its other existing and planned DSM programs and anticipates an overall reduction in its DSM programs.

NPC's plan also includes improvements in its transmission system to maintain adequate transfer capability levels. These improvements include the construction of a new 230-kV transmission project from the Arden Substation in the southeast part of the Las Vegas Valley to a substation in the northwest part of the valley, called the Northwest Substation. Additionally, NPC is planning to construct two new 230-kV switching stations in the Las Vegas Valley, the Gibson station and the Lake Mead/Eastern station.

The Action Plan section of NPC's Plan includes a detailed description of the competitive bidding process with a public request for proposals that the company went through to fill the company's future power supply requirements. The bids were first screened with PROVIEW and then further evaluated with PROMOD/PROSCREEN. NPC discovered a problem with the way that PROMOD III modeled pumped storage units. PROMOD III did not allow pumped storage units to use economy energy to pump. NPC and the affected bidder agreed to have EMA and Henwood Energy Systems, Inc. evaluate the problem. EMA used PROMOD IV which allows economy energy to be used for pumping purposes and Henwood used MULTISYM which also allows economy energy to be used for pumping purposes. The results from both models were comparable. A total of fifteen expansion plans were developed with the short-list of proposals and short-term firm power purchases. The lowest cost option relied on short-term firm purchases to meet the company's incremental capacity needs through 1998 rather than any of the proposed projects. Although NPC's study horizon extended through 2013, NPC's plan is based on the short-term.

NPC plans to enhance its modeling capability by upgrading to the multi-area version of PROMOD. In addition, NPC's Action Plan includes the request to hire a consultant to prepare a 10-year price and availability forecast of short-term firm and non-firm power purchases.

B.6.6 PACIFICORP
***POSITIONING FOR COMPETITION AND UNCERTAINTY, RESOURCE AND MARKET PLANNING PROGRAM (RAMPP-3),* APRIL 1994**

PacifiCorp, an investor-owned electric utility, provides energy services to customers in seven Western states through its Pacific Power and Utah Power divisions. The primary considerations used to develop RAMPP-3 include:

- Reduce long-term total resource costs;
- Achieve equity among customers;
- Meet increasing competition in the electric industry; and
- Reduce environmental emissions.

In its third RAMPP, PacifiCorp used the multi-attribute trade-off analysis (MATO) approach to integrated resource planning. PacifiCorp defines the MATO approach as testing many possible resource strategies against many possible futures. Resource strategies are defined by assigning restrictions to certain resource acquisition activities, e.g., the cost-effective level for demand-side management programs or exclude coal-fired resources. The possible futures these resource strategies are evaluated over include alternative levels of load growth, and also alternative fuel price projections. A set of strategies combined with a set of futures define a unique case; and a resource plan is developed for each case.

To perform the detailed analysis for the integrated resource planning, PacifiCorp selected Integrated Planning Model (IPM) by ICF Resources, Inc. IPM is a linear programming model that is capable of modeling a utility with several discrete regions and associated transmission constraints, and also capable of modeling hydroelectric resources in a limited manner. The system was modeled using six geographic areas. PacifiCorp minimize costs over a 50-year period, to capture the end effects of a 20-year planning period. The detailed resource selection analysis was prepared for 14 of the 20 years. The annual utility costs were then calculated for each year of the study period based on the resource selection for the closest years.

The modeling recognizes the non-firm purchase and sales activities Pacific Northwest, the Desert Southwest, and California. Historical trends for price and power availability was used to determine the price, seasonally and by time-of-day, and the quantity of power available. The price was assumed to escalate at the gas price escalation used in the particular run.

The environmental analysis was prepared using two different methodologies: the MATO approach defined above, and environmental adders. PacifiCorp found that both methodologies provided useful information. The PacifiCorp plans to refine its MATO approach in its next plan.

PacifiCorp recognized the following limitations with the modeling effort using IPM (1) transmission network representation is simplified, (2) time-period increment is limited to four seasons per year rather than hourly, and (3) expansion planning is limited to one user defined season and does not capture the immediate summer needs for the utility.

B.6.7 PLATTE RIVER POWER AUTHORITY, *RESOURCE INTEGRATION STUDY*, 1994

Platte River Power Authority (PRPA), a joint action agency, generates and transmits electricity for the Colorado Cities of Estes Park, Fort Collins, Longmont and Loveland. PRPA has existing resources sufficient to meet the requirements of its member cities for the next twenty years.

A major issue addressed in this IRP is the potential loss of peaking capacity from GCD, along with corresponding cost increases for their allocation of SLCA/IP power from Western. The results of the IRP show that demand-side management programs which will reduce system peak, along with a natural gas-fired peaking unit, will likely be the most economical replacement options for GCD peaking power.

Details of the software and modeling techniques used in this study are not provided in the study, although traditional power supply cost screening techniques appear to have been used.

Traditional power supply planning production cost analysis was used to determine the most cost-effective options. Costs were not assigned to externalities in this study, and PRPA explains that the lead of the Colorado Public Utilities Commission was followed in this respect.

B.7 REVIEW OF REGIONAL RFPS

During the past several years, Western has actively tracked selected regional electric utility planning activities and public solicitations of bids for power supply resources.. These public solicitations have included both supply-side and demand-side requests for proposals (RFPs), general requests for renewable resources, and targeted requests for renewable technologies, such as solar power.

Approximately 20 RFPs were analyzed for the purpose of identifying “ representative” request components. These

RFPs provide valuable background information to Western, and were relied on in determining recommended “ standard” components for future seasonal, mid-term and long-term requests for proposals by Western. By understanding the RFPs used by regional utilities, Western can improve and refine its future requests to potential regional suppliers.

Table B.6-1 contains a listing of the 20 selected regional RFPs that were analyzed. Table B.6-2 contains the listing of the all components which were included in these RFPs, including those components which requested basic bid source information. Finally, Table B.6-3 is a tabulation of all RFP components contained in each separate request for proposals.