1 of 1

**Salt Lake City Area Integrated Projects
Electric Power Marketing
Draft Environmental Impact Statement**

Volume 3: Appendix A

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COVER SHEET

Title: Salt Lake City Area Integrated Projects Electric Power Marketing Draft Environmental Impact Statement

Cooperating Agencies: U.S. Fish and Wildlife Service, the National Park Service, and the Bureau of Reclamation

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ABSTRACT

The Salt Lake City Area Office of the Western Area Power Administration (Western) markets electricity produced at hydroelectric facilities operated by the Bureau of Reclamation. The facilities are known collectively as the Salt Lake City Area Integrated Projects (SLCA/IP) and include dams equipped for power generation on the Green, Gunnison, Rio Grande, and Colorado rivers and on Deer and Plateau creeks in the states of Wyoming, Utah, Colorado, Arizona, and New Mexico. Of these facilities, only the Glen Canyon Unit, the Flaming Gorge Unit, and the Aspinall Unit (which includes Blue Mesa, Morrow Point, and Crystal dams) are influenced by Western power scheduling and transmission decisions. The EIS alternatives, called commitment-level alternatives, reflect combinations of capacity and energy that would feasibly and reasonably fulfill Western's firm power marketing responsibilities, needs, and statutory obligations. The viability of these alternatives relates directly to the combination of generation capability of the SLCA/IP with energy purchases and interchange. The economic and natural resource assessments in this environmental impact statement (EIS) include an analysis of commitment-level alternatives. Impacts of the no-action alternative are also assessed. Supply options, which include combinations of electrical power purchases and hydropower operational scenarios reflecting different operations of the dams, are also assessed. The EIS evaluates the impacts of these scenarios relative to socioeconomics, air resources, water resources, ecological resources, cultural resources, land use, recreation, and visual resources.

DOCUMENT CONTENTS

VOLUME 1

Summary

VOLUME 2

Summary

Section 1	Introduction
Section 2	Alternatives, Including No Action
Section 3	Affected Environment
Section 4	Environmental Consequences
Section 5	Cumulative Impacts of Commitment-Level Alternatives and Operational Scenarios
Section 6	Unavoidable Adverse Impacts
Section 7	Relationship between Short-Term Use of the Environment and Long-Term Productivity
Section 8	Irreversible and Irretrievable Commitment of Resources
Section 9	Environmental Statutes, Regulations, Executive Orders, and Permit Requirements
Section 10	Consultation, Coordination, and Public Involvement
Section 11	References
Section 12	List of Preparers
Section 13	Acronyms, Abbreviations, and Units of Measure
Section 14	Glossary
Section 15	Index
Section 16	List of Recipients

VOLUME 3

Appendix A Socioeconomics

VOLUME 4

Appendix B	Air Resources
Appendix C	Water Resources for Flaming Gorge Dam and the Aspinall Unit
Appendix D	Ecological Resources

CONTENTS — VOLUME 3

COVER SHEET	V3 - iii
DOCUMENT CONTENTS	V3 - v
APPENDIX A: SOCIOECONOMICS	A-1
A.1 Demand Analysis Methods	A-3
A.2 Power Systems Analysis Methods	A-4
A.2.1 Introduction	A-4
A.2.2 Commitment Level	A-5
A.2.3 Long-Term Firm Purchase	A-14
A.2.4 Determination of Dependable Capacity	A-14
A.2.5 Short-Term Firm Sales	A-15
A.2.6 Selection of Hydrologic Cases	A-15
A.2.7 Supply-Side Resource Expansion	A-16
A.2.8 Demand-Side Management Reductions	A-16
A.2.9 Modeling Purchase and Sales Contracts	A-18
A.2.10 Utility Dispatch	A-18
A.2.11 Spot Market Activities	A-19
A.2.12 Dispatch SLCA/IP Resources	A-19
A.3 Financial Analysis	A-19
A.3.1 Introduction	A-20
A.3.2 Classification of Western's Customers	A-20
A.3.3 The Utility Finance and Rate Impacts Model	A-21
A.4 Conservation and Renewable Energy Analysis Methods	A-25
A.5 Regional Analysis	A-26
A.5.1 Introduction	A-26
A.5.2 Calibration of the REMI and IMPLAN Modeling Systems for the Western Study Region	A-28
A.5.3 Specification of Data for Input to the REMI and IMPLAN Models	A-31
A.6 Recreation Analysis	A-32
A.6.1 Underlying Theory	A-32
A.6.2 Estimation Techniques	A-34
A.7 Irrigated Agriculture	A-37
A.7.1 Introduction	A-37
A.7.2 Scope of Analysis	A-38
A.7.3 Method of Analysis	A-38
A.8 References for Appendix A	A-39

FIGURES — VOLUME 3

A.1	Arizona Service Territory Map	A-7
A.2	Colorado Service Territory Map	A-8
A.3	Nevada Service Territory Map	A-9
A.4	New Mexico Service Territory Map	A-10
A.5	Utah Service Territory Map	A-11
A.6	Wyoming Service Territory Map	A-12
A.7	Overview of Power Systems Modeling Methodology for SLCA/IP Power Marketing EIS	A-13

TABLES — VOLUME 3

A.1	Utility Systems Modeled in Detail for the Power Marketing EIS	A-6
A.2	Counties Included in the Nine Subregions	A-29

**APPENDIX A:
SOCIOECONOMICS**

APPENDIX A: SOCIOECONOMICS

A.1 DEMAND ANALYSIS METHODS

This section describes the methods used to estimate the electricity demands of each of the end-user classes served by Western's customers. The purposes of the demand analysis were to (1) forecast the growth in the load (i.e., the amount of energy sold) served by each of the utility systems serviced by the Salt Lake City Area (SLCA) Office over the period 1993-2008,¹ and (2) estimate the price elasticity of demand for all the major end-user classes and customer groups. The results of the demand analysis were used as inputs to the power system analysis described in Section A.2.

The demand analysis used statistical regression methods together with stratification as necessary. Nonparametric methods were used in situations where they were most beneficial in determining attributes of the demand and price relationship that parametric methods would not readily uncover. The detailed steps of the analysis are briefly described below. A more detailed description of the demand analysis and resulting empirical results are presented by Morey and Ungson (1993).

The first step in the process was the analysis of customer demand data and other relevant variables. This step included identification and characterization of homogeneous customer groups and end-user service classes. It also required the empirical investigation of the variables relevant to the estimation of demand functions for the end-use customer classes served by Western's customers. This investigation included (1) examination of demand history (1980-1990) of end-user classes for Western's customers, (2) characterization of empirical distributions of energy and peak demand variables, (3) examination of economic data obtained from DRI/McGraw-Hill, (4) examination of weather variables provided by the National Climatic Data Center (National Oceanic and Atmospheric Administration 1991), and (5) examination of local economic variables and indicators deemed relevant to the analysis.

The second step involved the preliminary estimation of energy demand forecasts for the major utility systems served by Western's SLCA Office. Although other utilities serve parts of the region served by Western power, no analysis has been performed on the effects of changes in Western's operations or allocation procedures on non-Western utilities or their customers because it is not known how these utilities would be affected. The preliminary forecasts were used by the power system task group to initiate the analysis of capacity expansion, and the estimations provided experience dealing with the sometimes severe data limitations that inevitably accompany such a project. Most of the initial estimates were developed by time-series methods, although some preliminary models for customer classes were developed as well.

¹ The year 2008 was chosen as the final year for the study period because this is the year in which long-term firm (LTF) sales contracts for customer utilities expire.

The third step in the analysis was the estimation of short- and long-term price elasticities of demand for all major end-user classes and customer groups. It was important to have measures of the incremental effects of price changes in both the short term and the long term. Time-series studies were used in the estimation of short-term price elasticities. Long-term elasticities were developed through the use of nonparametric regression methods.

The fourth step was the statistical testing for structural shifts in demand functions during the 1980s and the statistical examination of the relationship between price elasticities of demand and prices for selected end-user customer groups. This part of the investigation relied on traditional regression-based methods. Where structural shifts were found, the estimated functions were further examined.

The next task in the analysis was construction of a baseline forecast of load from the DRI/McGraw-Hill trend scenario of independent variables. A load forecast was developed for each major system modeled in the power systems analysis. The forecasts showed a range of annual growth rates ranging from 0.5 to 2.9% for the forecast period.

The final task in the demand analysis was the inclusion of short-term forecasts of load growth from Western's customers. For the expansion period it was felt that Western's customers would have a better vantage point to foresee short-term changes in their service territory sales and peak demands than analysts from outside the region. To incorporate this better vantage point, the first three years of demand projections were drawn from forecasts supplied by the utilities. It was felt that in later years (after 1995), the advantage of better regional knowledge would diminish, and the needs for consistency of method across forecasts for different utilities would increase. The forecast, therefore, used the growth rates developed through econometric modeling of the individual systems to develop the energy and peak demand forecasts from 1996 through 2008.

A.2 POWER SYSTEMS ANALYSIS METHODS

A.2.1 Introduction

This section describes the methods used to simulate electricity production, forecast utility capacity expansion, and estimate air emissions for utility systems that could be affected by the commitment-level alternatives. The Production and Capacity Expansion (PACE) Model, estimated the effects of each alternative on Western's SLCA Office and its LTF customers. The PACE Model consists of a set of integrated electric utility system modules that are configured to analyze various aspects of utility dispatch, capacity expansion, and air emissions. Some of the modules and computational techniques employed in the analysis have been used for previous projects. A more detailed description of the power systems analysis and results are presented in Veselka et al. (1994).

Several aspects of electric utility systems were analyzed, including (1) historical loads, (2) hourly demand projections, (3) utility dispatch and supply expansion, (4) spot

market transactions, (5) hydroelectric operations, and (6) air emissions. Detailed simulations were performed for several utilities in the SLCA Office's marketing area. Utilities in this marketing area range in size from small municipalities to large investor-owned utilities that have service territories spanning several states. In general, larger utilities own and operate generating resources and have extensive transmission capabilities. A few of the larger systems also have load control responsibilities. Smaller systems have very limited or no generating resources and rely principally on purchases to meet load.

The utilities that were modeled in detail are listed in Table A.1. Figures A.1 through A.6 show the service territories of the major customer utilities served by Western power. A utility was selected for detailed analysis either because (1) it is a SLCA LTF customer that is relatively large in size compared to other SLCA LTF customers and has a significant allocation of SLCA capacity and energy or (2) it is a large investor-owned utility that purchases from SLCA on the spot market and is interconnected with SLCA LTF customers. The 12 LTF customers listed in Table A.1 account for approximately 80% of Western's LTF capacity and energy commitments under the no-action alternative. Because the smaller utility systems do not have any generating capacity and must purchase power to serve customer load, these were not modeled in the analysis of power systems. The impacts of EIS alternatives on small utility systems were assessed with financial modeling methods described in Section A.3.

The PACE modeling system was configured to project the future behavior of affected electric utilities under baseline conditions and to measure the impacts of altering Western's long-term firm sales programs (commitment levels) and dam operations. The schematic diagram in Figure A.7 provides an overview of the power systems modeling method. The modeling system was designed such that decisions concerning supply-side expansion, demand-side management, and hourly purchases of SLCA long-term firm energy are made for each individual utility system. Economic transactions between utility systems are made through spot market simulations and the modeling of existing long-term firm contracts.

A.2.2 Commitment Level

Through its long-term firm marketing program, Western sells wholesale, long-term, noninterruptible electric services to qualified preference entities. Under a long-term firm contract, a customer (i.e., preference utility system) has a seasonal energy and capacity allocation from Western for a specified term. Firm energy can be used at the customer's discretion, subject to certain maximum and minimum limits, and contractual restrictions. For this EIS, it was assumed that all contracts would be effective for 15 years. Four different commitment-level alternatives were analyzed in detail for this EIS. These include (1) high capacity and high energy, (2) high capacity and low energy, (3) low capacity and low energy, and (4) low capacity and low energy.

TABLE A.1 Utility Systems Modeled in Detail for the Power Marketing EIS

Utility Name	Abbreviation	Location	Type	Western LTF Customer
Arizona Power Pooling Authority	APPA	Arizona	Federal, state, and district	Yes
Arizona Public Service Company	APS	Arizona	Investor owned	No
Colorado-Ute Electric Assn. Inc.	Col-Ute	Colorado	Rural electric cooperative	Yes
Colorado Springs Dept. of Utilities	Col. Springs	Colorado	Municipal	Yes
Deseret Generation & Transmission Coop. ^a	Deseret	Utah	Rural electric cooperative	Yes
Farmington Electric Utility	Farmington	New Mexico	Municipal	Yes
Nevada Power Company	NPC	Nevada	Investor owned	No
PacifiCorp (Utah Power Division)	PacifiCorp	Utah	Investor owned	No
Plains Electric Generation & Transmission Coop. Inc.	Plains	New Mexico	Rural electric cooperative	Yes
Platte River Power Authority	PRPA	Colorado	Federal, state, and district	Yes
Public Service Company of Colorado	PSCO	Colorado	Investor owned	No
Salt River Project Agricultural Improvement & Power District	SRP	Arizona	Federal, state, and district	Yes
Tucson Electric Power Company	TEP	Arizona	Investor owned	No
Tri-State Generation & Transmission Assn. Inc.	Tri-State	Colorado	Rural electric cooperative	Yes
Utah Associated Municipal Power Systems	UAMPS	Utah	Federal, state, and district	Yes
Utah Municipal Power Agency	UMPA	Utah	Federal, state, and district	Yes
Wyoming Municipal Power Agency	WMPA	Wyoming	Federal, state, and district	Yes

^a Because of the relatively small size of this cooperative, the nature of its supply-side resources, and lack of data, capacity expansion and dispatch runs were not performed for this system. However, a detailed financial analysis was performed.

FIGURE A.1 Arizona Service Territory Map

FIGURE A.2 Colorado Service Territory Map

FIGURE A.3 Nevada Service Territory Map

FIGURE A.4 New Mexico Service Territory Map

FIGURE A.5 Utah Service Territory Map

FIGURE A.6 Wyoming Service Territory Map

FIGURE A.7 Overview of Power Systems Modeling Methodology for SLCA/IP Power Marketing EIS

A.2.3 Long-Term Firm Purchase

Because of the noninterruptible nature of SLCA's LTF capacity and energy commitments, Western must make purchases from other utility systems when it is unable to supply sufficient firm capacity and/or energy from its own hydroelectric generating resources. When marketing long-term firm capacity and energy, Western must consider elements that are outside of its influence and such well-known factors as hydroelectric generator nameplate capacities and transmission limitations. Because of the external influences, Western's resources are often highly variable over time. Therefore, Western is at risk of not fulfilling its contractual obligations when it offers firm capacity and energy to its customers. However, there are a number of ways for Western to minimize such risks. For example, its purchasing programs allow Western to secure generating capacity and energy from other electric utility companies.

For this analysis, estimates of LTF purchases were based on Western's LTF commitment level, projected average hydroelectric energy, projected hydroelectric capacity at a 90% exceedance level, project use (e.g., priority obligations to the Bureau of Reclamation), and system considerations (e.g., losses and Inland Power Pool obligations). It was assumed in the analysis that when Western's risk of not meeting all of its capacity obligations exceeded 10%, Western would purchase LTF capacity to reduce its long-term risk. LTF energy would be purchased when Salt Lake City Area Integrated Projects (SLCA/IP) obligations were greater than average hydroelectric generation. Under adverse conditions, i.e., when hydroelectric resources and long-term firm purchases would be inadequate to meet Western's firm obligations, short-term firm and spot market purchases would have to be made.

A.2.4 Determination of Dependable Capacity

One factor that has a large impact on the amount of LTF capacity that Western must purchase is operational restrictions at each of the hydroelectric facilities. Three different supply options were analyzed in detail: (1) high operational flexibility, (2) moderate flexibility, and (3) low flexibility. Under the high flexibility option, hydroelectric units would have no institutional ramp rate² limitations and could operate under a wide range of release levels. For most facilities, the amount of dependable capacity available under the high flexibility case depends on the amount of water behind the dam. The low flexibility option specified constant seasonal release from all dams. Under this option, the capacity of each dam would be equal to the generation at constant flow.

The moderate flexibility case is identical to the full flexibility case except that there would be hourly and daily ramp rate restrictions at Glen Canyon Dam. Also, the maximum release at Glen Canyon Dam would be lowered in all but the wettest years. To determine dependable capacity under these operational conditions, a simple geometric algorithm was

² Ramping refers to a change in the amount of water flowing past the dam. Ramp rate refers to the change in flows measured over a specific time period.

developed. The objective of the geometric approach was to estimate the maximum generation level that could be achieved for each peak day during one month. The algorithm accounted for flow restrictions at dam sites, including limits on upramp and downramp rates, maximum daily fluctuations, and minimum and maximum flow rates. The geometric approach also recognized Sunday as an off-peak period and accounted for the amount of energy that could be released in each month and the length of time that the capacity must be available during on-peak periods.

A.2.5 Short-Term Firm Sales

Short-term firm (STF) sales are offered by Western if projected supply resources exceed long-term firm commitments. STF capacity and energy commitments are contractual power agreements that are either seasonal or monthly. For the purposes of the analysis, it was assumed that surpluses are first marketed to Western's preference customers. Any remaining power is then offered to nonpreference customers. If LTF commitments are low and supply resource levels are high, the excess above the long-term commitments will occur frequently. Thus, Western has numerous opportunities to offer its customers STF resources. At the other extreme, if Western's LTF commitments are high and supply resources are low, excess resources will occur very infrequently (if ever), and STF sales will be at a minimum. Low supply-side conditions occur under one or more of the following circumstances: (1) hydro conditions are dry, (2) stringent operational restrictions are in place, and (3) LTF purchases are small or nonexistent. For this analysis, excess energy resources were allocated to individual SLCA firm customers on a prorata basis up to the point that the load factor on SLCA's contracts (LTF + STF) equaled 100%. In addition, no excess capacity was offered to any customer.

A.2.6 Selection of Hydrologic Cases

Operations of SLCA/IP hydroelectric resources and STF sales depend on hydrologic conditions. Therefore, three hydrologic conditions — wet, moderate, and dry — were analyzed in this study. The three conditions were selected on the basis of results from the Colorado River Simulation Model (CRSM).

The CRSM is a deterministic model developed by the U.S. Bureau of Reclamation (Reclamation). It estimates monthly water releases from the Colorado River Storage Project (CRSP) and Seedskedee Project dams in accordance with all the water laws pertaining to the Colorado River. Also factored into the model are the requirements of operating criteria for maintaining equal storage in Lake Powell and Lake Mead so long as sufficient upper storage basin exists for a targeted release of at least 8.23 million acre-feet from Glen Canyon. The model uses historical hydrological data from 1906 through 1990 to simulate river basin flows and end-of-the-month reservoir levels. The CRSM was used to produce different potential capacity and energy outcomes for each month of the study period (i.e., January 1993 through December 2008) for each CRSP dam.

The CRSM estimates of monthly capacity and energy, along with typical values for the Rio Grande and Collbran projects, were input into a clustering algorithm that partitioned capacity and energy estimates into three different clusters representing dry, moderate, and wet conditions. This procedure produced average estimates of capacity and energy for each hydrological condition. This method was used because it considers both capacity and energy simultaneously.

A.2.7 Supply-Side Resource Expansion

Based on SLCA LTF capacity and energy commitment levels, supply-side expansion paths for each of the 17 utility systems listed in Table A.1 were determined with the BUILD module of PACE. BUILD selects a supply-side path by assembling various combinations of expansion states or "snapshots" in time into a time sequence of capacity expansion paths. The model uses a dynamic modeling approach that minimizes the number of paths that must be explored to arrive at the least-cost solution. The amount of capacity that must be built in the future depends on a number of factors, including (1) contractual capacity and energy agreements with another utility system, (2) projected demand, (3) demand-side management (DSM) programs, (4) committed units, (5) retirement schedules, and (6) system reliability targets.

Expansion paths were based on the assumption that each system is an independent entity that has LTF obligations to other utility systems. Therefore, supply-side expansion decisions were based on a utility systems' loads, resources, and LTF contractual agreements. Interactions among utility systems on the spot market and STF contracts were also estimated by PACE but did not affect DSM programs and long-term supply paths.

Forecasts of peak loads were modified and the penetration of DSM programs was estimated on the basis of initial estimates of short- and long-term marginal costs over a short period of time. Short-term marginal costs are the additional costs of increasing electricity production over a short period of time. Long-term marginal costs include capacity expansion and other fixed costs that will occur in addition to increased production costs if energy production is increased over a longer period of time. With adjusted load forecasts, least-cost supply-side expansion paths for affected utility systems were revised.

A.2.8 Demand-Side Management Reductions

The method used to estimate the load reductions from cost-effective DSM programs was patterned, in large part, after the method used by the Potomac Electric Power Company (PEPCO) in its 1990 and 1992 integrated resource plans (Hill et al. 1991). The initial step was to assemble a large set of DSM options for possible inclusion in the expansion plans. To accomplish this task, analysts consulted reports published by the Electric Power Research Institute and the SURIS database compiled by EPRI (see Cavallo et al. 1994 for details). Additional DSM options were drawn from material submitted as testimony from the executive director of the American Public Power Association to the U.S. House of Representatives,

Subcommittee on Water, Power and Offshore Energy Resources (Hobart 1992). In this initial step, no attempt was made to eliminate DSM programs or measures that might later be rejected as inappropriate for the local region. The initial set included over 100 DSM options.

After assembling the set of DSM options, analysts performed an initial screening to reduce the DSM options to a number both computationally manageable and inclusive of cost-effective programs. The initial screening rejected DSM options that failed to meet three criteria: (1) applicability in the Western region, (2) market maturity, and (3) acceptable level of reductions. These criteria were used to screen out possible DSM programs that were almost certain to fail to meet local needs in a cost-effective manner. The resulting set of DSM programs included 18 programs — 10 residential programs, 5 commercial-industrial programs, and 3 agricultural programs.

These 18 DSM programs were then modeled with the computer program DSManager developed by Electric Power Software for EPRI (Cavallo et al. 1994). DSManager uses program cost information, estimates of program participation, and marginal system cost estimates to compute the costs and benefits of proposed DSM programs. The output of the modeling with DSManager includes hourly load reductions for the expansion period from the individual DSM programs and benefit-cost ratios for each DSM program.

The marginal system cost estimates were generated from the PACE system modeling performed as part of the power systems analysis. By agreement with Western, one system (the City of Colorado Springs) was chosen for DSM modeling as a prototype. Appropriate program cost and participation were determined through consultation with experienced DSM analysts and were compared with ranges of estimates used in similar studies. The modeling results for Colorado Springs were generalized to the other systems served by Western by proportionally increasing or decreasing the individual hourly program reductions.

Five of the 18 DSM programs consistently displayed cost-effectiveness in all modeled alternatives as determined by the "total resources cost test." One other program was cost-effective in the baseline alternative but not in other alternatives. The cost-effective programs can be described as energy conserving rather than peak load managing. The reason for this result is the low cost of Western's power. It was found that in all alternatives studied, the hourly marginal system costs after accounting for power purchased from Western do not vary enough to provide an economic basis for peak load management programs such as direct load control of residential air conditioners or electric water heaters. The relatively low marginal system costs resulted in small total reductions from DSM programs and little difference in reductions among alternatives. In all years of the expansion period (1993-2008), DSM reductions never reached 2% of energy sales or peak demand. Also, the differences among alternatives due to DSM was small — approximately 0.2% of energy sales in the final year of the expansion period (Cavallo et al. 1994).

A.2.9 Modeling Purchase and Sales Contracts

Both existing and new long-term firm capacity and energy contracts between utilities were taken into account in the simulation of utility dispatch and supply-side expansion. The simulation method used depended upon the contract type and information provided by utility contacts. The methods presented below were tailored to best represent the unique terms and conditions of a specific contract. PACE uses several methods for estimating LTF contractual obligations between utility systems, including (1) hourly load modifications, (2) thermal unit representation, (3) limited energy source representation, and (4) load duration curve (LDC) modifications.

Terms and conditions of the SLCA commitments differ among commitment-level alternatives. However, all other LTF contracts between utility systems remained constant for all EIS alternatives. SLCA contracts were modeled with a load-modification algorithm that maximizes reductions in the system peak load, subject to a number of constraints. Constraints incorporated in to the model included maximum energy usage, minimum schedule requirements, maximum contract capacities, and maximum changes in hourly and daily schedules. The algorithm assumed that capacity and/or energy is prescheduled and cannot be used to replace resources during times of forced outages. Results from the load-reduction algorithm provided an estimate of hourly demands for SLCA LTF energy. That is, the loads reduced by the algorithm were those supplied by Western. SLCA supplies this energy through hydroelectric generation, LTF purchase agreements, and spot market sales. SLCA supply activities were estimated by the SLCA/IP dispatch algorithm.

A.2.10 Utility Dispatch

The Investigation of Costs and Reliability in Utility Systems (ICARUS) module was used to estimate electricity dispatch. ICARUS is an energy system planning tool for assessing the reliability and economic performance of alternative expansion paths of electric utility generating systems. The model calculates (1) a system maintenance schedule (if not fully specified), (2) the loss-of-load probability, (3) unserved demand for electrical energy, (4) required capacity reserve to meet a specified reliability criterion, (5) the effects of emergency interties, (6) expected energy generation and cost from each unit and block, (7) total generating system costs, and (8) fuel use. ICARUS uses a probabilistic simulation technique that significantly reduces computation requirements. Module calculations are based on system loads, unit-level generating resources, system operational constraints, and capacity and energy transfers among utility systems. ICARUS was used in conjunction with long-term expansion plans to produce hourly cost-production functions that in turn were used to simulate spot market activities.

ICARUS was also used to estimate the change in utility dispatch when Western sells short-term firm energy. Utility dispatch is based on a fixed capacity expansion plan as determined by the BUILD module of PACE.

A.2.11 Spot Market Activities

Spot market transactions between utility systems were estimated with the Spot Market Network (SMN) module. Estimates of spot market activities were made for all combinations of commitment-level alternatives, hydroelectric operational restrictions, and hydrologic conditions (i.e., dry, moderate, and wet). SMN is a linear program that assesses the effects of commitment-level alternatives on spot market activities and SLCA/IP hydroelectric operational constraints. Spot market transactions among the 17 utility systems shown in Table A.1 were estimated through the use of a network of nodes and links. In this network, nodes represent generating resources and load centers. Generating resources are represented as piece-wise linear marginal cost curves, and load centers are represented by estimates of hourly electricity demand. Nodes are connected by links that represent transmission limitations and line losses for power flows between nodes. The module minimizes production costs subject to utility-specific minimum profit margins that trigger spot market transactions. The module recognizes line ownership and includes wheeling, sales-for-resale transactions, and line usage that is reserved for LTF transactions.

A.2.12 Dispatch SLCA/IP Resources

Simulations of SLCA/IP dispatch were approximated by the Resource Dispatch Model (RDM). The RDM is a linear programming model that simulates the operation of SLCA/IP hydroelectric facilities and LTF purchase contracts to meet LTF loads. It also projects SLCA's hourly participation in spot market transactions. The module solves for hourly generation, purchases made under LTF contracts, and spot market activities on the basis of the assumption that Western maximizes the value of its hydroelectric resources and minimizes charge rates to long-term firm customers. Spot market activities were based on market prices as determined by SMN and Western's ability to shift hydroelectric generation from off-peak periods to on-peak periods. Spot market purchases and sales depend on the amount of water available for generation, Western's hourly firm commitments, flow restrictions at each of the hydroelectric dams, and Western's LTF purchasing programs. Operational restrictions incorporated into this module include (1) minimum and maximum flow restrictions, (2) hourly and daily ramp rate restrictions, and (3) minimum and maximum elevation levels at specific reservoirs. The RDM also includes a profit margin requirement for off-peak to on-peak hydroelectric shifting.

A.3 FINANCIAL ANALYSIS

This section provides an overview of the analytical framework used in performing the rate and financial impact assessment for the alternatives studied in this EIS. More detailed descriptions of the financial analysis and resulting empirical results are presented in Bodmer et al. (1994).

A.3.1 Introduction

Alternative commitment levels could change the cost of power to Western's customers, because Western's wholesale rates would have to be adjusted to meet its debt repayment obligations. In addition to producing cost changes, different programs could also affect the cost of alternative power and the capacity expansion plans of the utilities. The purpose of the rate and financial analysis was to quantify the full range of impacts that changes in the costs and quantities of Western's power could have on its customers. These impacts appear as changes in the financial health of the reselling utility and/or changes in the prices and the quantities of electricity consumed by residential, commercial, industrial, and other retail consumers.

The analysis of the impact on rates took into account the quantity adjustments consumers make when faced with changes in price. It also considered financial constraints of the utilities. The financial viability analysis estimated economic impacts that arise in cases where changes in Western's marketing programs might create potential financial difficulties for a utility. In such cases, utilities often do not make optimal investment and maintenance decisions because of financial constraints on capital investment. The uneconomical investment decisions could have harmful long-term impacts on consumers of electric power.

Retail rate impacts and financial viability were combined into one analytical process because there is a direct link between the financial condition of the utilities that sell power and the prices that consumers pay for electricity. For example, if costs increased and rates stayed constant, the impact of the cost increase would appear as a deteriorating financial condition of the utility. Alternatively, if the entire cost increase was passed on to the customers of the utility in the form of higher electric rates, there would be no financial impact on the utilities. The link between financial viability and electric rates is influenced by many factors. Rate differentials with neighboring utilities, management strategy, regulation, past investment in capacity, and consumers' willingness to buy all play a role in how cost changes are split between the utility and its customers. As changes in costs occur, the utility's manager decides (on the basis of multiple constraints) whether to increase or decrease its financial health or to increase or decrease rates to utility customers.

A.3.2 Classification of Western's Customers

Entities to whom Western sells power were classified into three different types: (1) customers that resell power directly to end-users (distribution utilities), (2) customers that resell power to other utilities that then resell the power to end-users (wholesale utilities), and (3) customers that do not resell the power but use it for their own purposes (retail end-users). Distributors include municipal utilities and distribution cooperatives that purchase and resell Western power directly to end-users. Generation and transmission cooperatives and joint-action agencies were classified as wholesale utilities because they primarily sell power to other utilities, which in turn resell the electricity to end-users. The retail end-users

classification contains military bases and other Federal installations, as well as universities and irrigation districts, that purchase power directly from Western but do not resell the power.

The analysis for each of these types of customers differed because of differences in the financial structure, rate-setting policy, and demand characteristics of the utilities. Because Western's retail end-users do not resell power, the impacts of each commitment-level alternative would be limited to a change in the rates Western charges and a corresponding change in the quantity of electricity consumed by each retail end-user. Distributors and wholesalers, however, have the option of either altering rates or absorbing costs through changes in financial position. Consequently, the analysis had to take into account how each of these types of customers would alter its rates and financial standing to accommodate changes in the costs of acquiring power.

A.3.3 The Utility Finance and Rate Impacts Model

Even though distributors and wholesalers both have the option of altering rates or absorbing costs internally, the two types of utilities required different modeling approaches. Since distributors sell primarily to end-users and do not sell electricity for resale, the demand for power from distributors comes from their end-use customers. In contrast, wholesaler utilities primarily sell bulk electric power to distribution utilities and other wholesale utilities. Thus, wholesale demand is a derived demand from the utilities that ultimately sell to the end-users.

Argonne National Laboratory (ANL) developed a utility financial model to help analyze management strategies of utility companies. The model was initially constructed to compare the effects of different management strategies facing utility managers. For example, the model can project the effects of financing a new plant with equity or debt, as well as any combination of equity and debt. The model can also project future revenues by customer classes in response to changes in costs, including an elasticity adjustment for end-user response to changes in prices. The model can determine purchased power costs on the basis of a portfolio of purchased power contracts.

The financial model has been developed over a number of years on the basis of consultations with utility companies, government agencies, and consulting firms. The model generates output on retail prices and financial viability on the basis of cost structure, demand, and the rate-setting policy of the utility. For the purposes of this EIS, application of the model differed depending on whether a wholesale or a distribution utility was being modeled.

At the core of the model are two equations that define an entity's income and interest coverage. To simplify the discussion of the model, the following "stripped-down" equations are presented to illustrate the general algorithms:³

$$\text{Income} = \text{revenue} - \text{operating cost} - \text{interest cost} \quad (\text{A.1})$$

$$\text{Interest coverage} = (\text{income} + \text{interest cost})/\text{interest cost}. \quad (\text{A.2})$$

Equations A.1 and A.2 are the basis of the financial model. Substituting for income in Equation A.2 and simplifying yields:

$$\text{Interest coverage} = (\text{revenue} - \text{operating cost})/\text{interest cost} \quad (\text{A.3})$$

or

$$\text{Revenue} = \text{interest coverage} \times \text{interest cost} + \text{operating cost}. \quad (\text{A.4})$$

In addition, the average rate paid by the utility's end-users is calculated as

$$\text{Rate} = \text{revenue}/\text{sales}. \quad (\text{A.5})$$

Note that Equations A.3 and A.4 can be used to examine the effect of a change in one component on the other components of the equation. For example, if operating costs were to change and revenue and interest costs remained constant, the interest coverage would have to change in the opposite direction. In a similar manner, if interest costs increased, either revenues would have to increase or operating costs would have to decrease for the interest coverage to remain constant.

Equations A.3 and A.4 capture the link between the financial health of the utility (as measured by interest coverage) and the revenues the utility receives. Thus, a change in operating cost, as represented as a change in the cost of Western power (or the cost of adding/replacing Western power), could show up as a change in the interest coverage, a change in revenues, or both. Taken together, Equations A.3, A.4, and A.5 show how the link between the financial health of the utility and the revenues that the utility receives can be used to quantify the effects of a change in Western's commitment levels on both the financial condition of the utility and the rate paid by electricity end-users.

The model explicitly takes into account the customer's response to price changes through an elasticity adjustment. Such an adjustment is important because it has implications for covering operating costs that are not directly related to the level of output. Some costs, like production costs, increase or decrease with the level of electricity sold. Other costs, such as distribution, sales, and administrative costs, do not depend on the amount of electricity sold. These relatively fixed operating costs are incurred regardless of sales revenues.

³ These equations are representative of the actual equations used in the model.

The model relates the coverage of these relatively fixed costs to the elasticity adjustment. If demand is price inelastic, an increase in price induced by a cost increase leads to a reduction in quantity demanded. This leads to a reduction in revenues. If fixed costs are to be covered, a further increase in price is necessary. This price increase leads to a further reduction in quantity demanded, and this iteration starts again. It is possible for these effects to cycle out of control, leading to a "death spiral" for the utility. However, if the elasticity effect is minor and the fixed portion of operating costs is small, the price and quantity adjustments converge so that further price increases do not induce a significant reduction in demand.

The ANL approach to modeling distribution utilities used data from the demand and power system subtasks and produced data on rates, bills, and financial condition. Interest and depreciation costs were computed on the basis of existing financial structure and the projected capacity additions. Nonproduction costs were computed from regression analysis and the database of historical costs. The projections of baseline financial status were compiled on the basis of inputs collected from the companies' financial records, secondary data sources collected from Federal and state reporting requirements, and other inputs and assumptions as outlined below:

- Historical rates, sales, and energy disposition from EIA Form 861;
- Forecasts of peak demand and energy sales from the companies and other sources;
- Projected production costs from the power systems production analysis;
- Nonproduction costs; and
- Other economic variables, such as inflation, carrying costs, and input prices.

Purchased power costs were derived from the power systems analysis and the Western marketing programs.

The link between rates and the financial condition of utilities was an important part of this analysis. Modeling of the relationship between the financial condition of the utility company and rates paid by consumers is illustrated by the following four-step process:

- Step 1: Compute prices on the basis of historical financial criteria such as debt service criteria.
- Step 2: Examine prices generated from Step 1 in terms of the overall level and the year-to-year change.
- Step 3: Determine the maximum year-to-year price increases and maximum absolute levels on the basis of neighboring utilities, management policy, empirical data analysis, and judgment.

Step 4: If the prices examined in Step 2 exceed the constraints determined in Step 3, run the model on the basis of constrained prices rather than the financial driver from Step 1.

Modeling of wholesale utilities differed from the modeling of the distribution utilities. For the wholesale utilities, the power cost was modeled directly in the power systems analysis. Other modeling algorithms are similar (e.g., between the wholesale utility and the distribution utility). It is important to note how the modeling integrated distributors and wholesalers. It is common for the wholesaler to purchase power from Western and other sources and then resell the power to its affiliated distributors, as well as to the end-use consumers of the wholesaler. In modeling this situation, the impacts of commitment-level alternatives on the wholesaler's required revenues reflected the cost changes attributable to the commitment-level alternative as well as the effects of changes in demand by both the distributors and end users with whom the wholesaler does business. The differences in cost and required rates for the distributor affect the demand for electricity from the distributor's end-use customers, which in turn affects the demand and revenue of the wholesale utility.

The crux of the relationship between modeling distribution utilities and wholesale utilities is that the production costs incurred by the distribution utility are equivalent to rates of the wholesale utility. In addition, the overall retail demand from the distribution utility (including line loss) is also demand to the wholesale utility.

The financial analysis was organized so as to provide information similar to that of financial statements prepared for annual reports of corporations. This information included income statements, supply analyses, balance sheet information, cash flow statements, financial ratio analysis, and a price analysis by customer class for each utility examined in the impact analysis. In the income statement analysis, the "operating revenue" projections were made on the basis of a demand analysis performed earlier (Morey and Ungson 1993) and were broken down by end-user categories: residential, irrigation, commercial, industrial, and public lighting. Operating revenues represent sales that the retail utility earns from its end-use customers.

The "operating expenses" were estimated for the various costs incurred by the retail utility. The cost of bulk power was projected on the basis of a production cost analysis. Other miscellaneous expenses, such as administrative, sales, and general expenses, were projected on the basis of a regression analysis. Other income sources, such as generation and transmission credits, nonoperating margin on interest, and extraordinary items, were added to operating income. Interest paid on both long- and short-term debt was subtracted from operating income. Interest expense was calculated on the basis of projected financing requirements, debt maturities, and interest rates. When factored in, these additions and subtractions yielded the retail utility's "net margin" or profit. The net margin plus depreciation equals the working capital for the municipal utility system. Operating cash flow minus capital expenditures yields cash flow before financing. Cash that must be raised externally was determined on the basis of cash after capital expenditures and debt market conditions.

The supply analysis calculated sales/price statistics, peak load and capacity, and fuel cost and fuel clause information. The sales/price statistics include energy sold and the average retail price paid for electricity over all rate categories. From this the average revenue was calculated (in \$/MWh).

A.4 CONSERVATION AND RENEWABLE ENERGY ANALYSIS METHODS

This section describes the methods used to assess the impacts of the commitment-level alternatives on current conservation and renewable energy (C&RE) activities. A more detailed discussion of the methods and empirical results is presented by Cavallo et al. (1994).

All of Western's long-term firm power customers were required to implement three to five C&RE activities, depending on the customer's size. Western designed its C&RE requirements to promote the efficient use of energy and to facilitate the use of renewable energy sources. Some activities were designed to improve energy consumption efficiency or reduce peak load. Other activities were developed to use renewable sources of energy supply or to cogenerate electricity with the use of energy for some other purpose. Although cooperative or municipal utilities could have adopted new C&RE activities or expanded participation for a variety of reasons (such as reduced dependence on outside power or an improved global environment) the analysis developed for this EIS postulated that additional C&RE activities would only be implemented if the utilities found economic advantage in such new activities. Similarly, it was assumed that C&RE activities would not be expanded if the costs of such expansion exceeded the benefits.

The C&RE analysis was divided into four parts: (1) identifying currently operating C&RE activities of each utility, (2) estimating the energy and peak demand reductions attributable to each activity, (3) identifying the activities that would likely be affected by a change in Western's commitment levels, and (4) modeling the potentially affected activities with the marginal system costs of the alternative showing the greatest deviation from the baseline. The initial step in the C&RE analysis was the identification of C&RE activities. Analysts developed an extensive database from the C&RE files of Western's SLCA Office. As described by Cavallo et al. (1992), the database contains 1,242 entries and tracks the development of C&RE activities at the cooperatives and municipals served by Western's SLCA Office. Extensive descriptions of individual activities are given in the database, along with the size and type of utility employing the activity.

The second step of the analysis was to estimate reductions realized by Western's customers from their C&RE activities. Since quantitative program evaluations of activities are not performed by Western or its customers, this information is not readily available. To develop rough quantitative estimates of the reductions from the activities, analysts solicited information from Western's customers through telephone conversations. This information was compared to and expanded with estimates from EPRI publications. The estimates of the energy and peak demand reductions from C&RE activities are detailed in Cavallo et al. (1994).

After estimating the reductions associated with the C&RE activities, analysts identified the activities most likely to be affected by a shift from the baseline to an alternative commitment level. Many activities, such as those associated with production efficiency, were unlikely to be affected. Furthermore, the results of the power systems analysis indicated that renewable energy programs and cogeneration were not cost-competitive under any of the commitment-level alternatives and, thus, could be excluded. The remaining activities included consumption efficiency and load-management activities.

The final step in the C&RE analysis involved modeling the costs and reductions of the remaining activities under the conditions of the alternative showing the greatest deviation from the baseline — commitment-level alternative 4. The activities remaining after the third step were similar to the DSM programs being modeled as part of the capacity expansion analysis, and therefore the modeling task was combined with the DSM program analysis. Each type of activity was matched with a similar DSM program among the 18 DSM programs modeled for capacity expansion. The 18 DSM programs were then modeled with the EPRI software DSManager (see Cavallo et al. 1994 for details). DSManager uses program cost information, estimates of program participation, and marginal system cost estimates to compute the costs and benefits of proposed DSM programs. The marginal system cost estimates were generated from the PACE system modeling performed in the power systems analysis. Appropriate program costs and participation were determined through consultation with experienced DSM analysts and compared with ranges of estimates used in similar studies.

A.5 REGIONAL ANALYSIS

This section describes the methods used to assess the regional economic impacts of the commitment-level alternatives and presents extended empirical results. A more detailed discussion of the methods and empirical results is presented by Allison and Griffes (1994).

A.5.1 Introduction

The regional impacts assessment used the Regional Economic Models, Inc. (REMI) and Impact Analysis for Planning (IMPLAN) modeling systems to obtain comprehensive information on selected socioeconomic impacts of the various commitment-level alternatives. Compared with alternative input-output (I-O) and econometric modeling frameworks, the REMI modeling system provides a substantial amount of information for a range of region-specific variables important to the measurement of economic impacts. The REMI modeling system combines this information in a general equilibrium framework that can be used to estimate the impacts of changes in a wide range of policy variables.⁴ The core of the REMI modeling system is an I-O structure representing interindustry linkages and linkages to final demands by industry. The modeling system also includes substitution among factors of

⁴ A description of the REMI modeling system is provided in Treyz (1993).

production in response to changes in relative factor costs, migration in response to changes in expected income, wage responses to changes in labor market conditions, and changes in the share of local and export markets in response to changes in regional profitability and production costs.

The basic REMI modeling system has five parts. Output linkages, or I-O accounts, represent the core of the system to show interindustry linkages and endogenous final demand. The standard REMI modeling system is based on a 53-sector model of the U.S. economy, regionalized through the use of location quotients, to produce interindustry tables at the county level. Final demand in the modeling system includes 25 sectors. Also included is an occupational matrix including 94 occupational groups that provides output on likely changes in occupational structure given any change in final demand in each county economy. Within this matrix, 202 age/sex cohorts also give additional information on the demographic impacts of changes in exogenous expenditures.

The interindustry section of the system is linked to an econometric model with four distinct blocks, with extensive linkages among the various blocks. Outputs in the I-O block drive labor demand, with labor demand interacting with labor supply to determine wages. In tandem with other factor costs, wages determine relative production costs and relative profitability, which in turn affect market shares. The market-shares block models the proportion of local demand and exogenous export demand in the region that is filled by local production.

Endogenous final demands include consumption, investment, and state and local government demand. Real disposable income drives consumption demands. Nominal disposable income is derived as wage income, plus property income related to population calculated, plus transfer income related to population minus employment and retirement population, minus taxes. Real disposable income comes from nominal disposable income deflated by the regional consumer price deflator. Optimal capital stock determines state and local final demand, and the endogenous final demands, combined with exports, determine outputs.

The REMI modeling system was used to estimate the impact of the various commitment-level alternatives on population, gross regional product (GRP), disposable income, and employment. Measurement of the income distribution impacts used the IMPLAN modeling system combined with disaggregated information on the household and consumption sectors of the input-output table. These modifications used data from the Bureau of Labor Statistics, the New York Stock Exchange, and the Internal Revenue Service. The modified model contains a series of income accounts showing information on the sector and income bracket of recipients and the sector and income bracket of consumers. The model was used to estimate the impact of changes in final demand (changes in electricity expenditures) on changes in individual household income for 11 household income groups. A more detailed discussion is provided in Rose and Frias (1993a,b).

A.5.2 Calibration of the REMI and IMPLAN Modeling Systems for the Western Study Region

The counties that make up the "affected area" for Western operations were defined by calculating the proportion of power consumed in each county in 12 states that is provided by Western. Included was power coming from Western either directly, in a small number of cases, or indirectly through the various distribution cooperatives, Rural Electric Associations, and other such entities to which Western sells power. Individual counties were then combined into groups of counties to produce nine subregions. The counties were grouped together on the basis of similarities of economic structure. Individual REMI and IMPLAN models were then constructed for each of these subregions. As discussed below, the groupings included six metropolitan subregions and three rural subregions.

A.5.2.1 Metropolitan Subregions

Each of the six states in Western's affected area — Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming — has at least one metropolitan county. Within these counties, the larger metropolitan centers of Phoenix (Maricopa County; 1988 employment of 975,200), Denver/Boulder (Adams, Arapahoe, Boulder, Denver, and Jefferson counties; 952,200), and Salt Lake City (Davis, Salt Lake, and Weber counties; 473,500) have highly diversified economies, with a range of manufacturing, consumer, and producer service activities. Las Vegas (Clark County; 270,247) is a growing regional center based on gaming and hospitality industries and is attempting to diversify its economy. For all but two of these counties, at least 80% of the population is located in urban areas. Additionally, for the majority of these counties, agricultural and resource extraction industries constitute less than 2% of total county employment. A number of smaller metropolitan centers — Albuquerque/Santa Fe (Bernalillo and Santa Fe counties; 210,152), Colorado Springs (El Paso County; 122,359), Fort Collins (Larimer County; 50,613), Greeley (Weld County; 34,501), Pueblo (Pueblo County; 30,159), Casper (Natrona County), and Tucson (Pinal County; 14,632) — specialize in a smaller number of activities, with an emphasis on service employment. Each of these counties has an essentially urbanized population, and less than 5% of its employment is in agriculture and resource extraction.

These metropolitan areas were grouped to create six separate subregions — the Arizona Metropolitan, Colorado Metropolitan, Nevada Metropolitan, New Mexico Metropolitan, Utah Metropolitan, and Wyoming Metropolitan subregions (Table A.2).

A.5.2.2 Rural Subregions

The remainder of the counties in each of the states served directly or indirectly by Western are rural, and in many cases remote, with few large centers of population. The economies in these counties are based primarily on agriculture, resource extraction, recreation, and tourism. These counties were grouped into three separate rural subregions for a total of nine subregions for the regional impact analysis (Table A.2).

TABLE A.2 Counties Included in the Nine Subregions

Subregion	States	Counties
<i>Metropolitan Subregions</i>		
Arizona	Arizona	Maricopa, Pinal, Pima
Colorado	Colorado	Adams, Arapahoe, Boulder, Douglas, Jefferson, El Paso, Larimer, Weld, Pueblo
Nevada	Nevada	Clark
New Mexico	New Mexico	Bernalillo, Los Alamos, Santa Fe
Utah	Utah	Davis, Salt Lake, Weber, Utah
Wyoming	Wyoming	Natrona
<i>Rural Subregions</i>		
High Plains	Colorado	Baca, Bent, Cheyenne, Crowley, Elbert, Kiowa, Kit Carson, Las Animas, Lincoln, Logan, Morgan, Otero, Phillips, Prowers, Sedgwick, Washington, Yuma
	Montana	Big Horn
	Nebraska	Arthur, Banner, Box Butte, Chase, Cherry, Cheyenne, Dawes, Deuel, Dundy, Garden, Grant, Hayes, Hooker, Keith, Kimball, Lincoln, McPherson, Morrill, Perkins, Scotts Bluff, Sheridan, Sioux
	New Mexico	Chaves, Colfax, Curry, De Baca, Eddy, Guadalupe, Harding, Lea, Mora, Quay, Roosevelt, San Miguel, Union
	Oklahoma	Cimarron
	Texas	Cochran, Gaines, Hartley, Yoakum
	South Dakota	Fall River
	Wyoming	Albany, Campbell, Converse, Goshen, Johnson, Laramie, Niobrara, Platte, Sheridan, Weston
Rocky Mountains	Arizona	Cochise, Graham, Greenlee
	Colorado	Alamosa, Archuleta, Chaffee, Clear Creek, Conejos, Costilla, Custer, Eagle, Fremont, Gilpin, Grand, Gunnison, Hinsdale, Huerfano, Jackson, La Plata, Lake, Mineral, Ouray, Park, Pitkin, Rio Grande, Routt, Saguache, San Juan, Summit, Teller
	Montana	Carbon
	New Mexico	Catron, Cibola, Grant, Hidalgo, Lincoln, Luna, McKinley, Otero, Rio Arriba, Sandoval, Sierra, Socorro, Taos, Torrance, Valencia

TABLE A.2 (Cont.)

Subregion	States	Counties
<i>Rural Subregions (Cont.)</i>		
Rocky Mountains (Cont.)	Utah	Daggett, Morgan, Summit, Wasatch
	Wyoming	Big Horn, Carbon, Fremont, Hot Springs, Lincoln, Park, Sweetwater, Uinta, Washakie
Great Basin	Arizona	Apache, Coconino, Gila, La Paz, Mohave, Navajo, Santa Cruz, Yavapai, Yuma
	California	Inyo, Mono
	Colorado	Delta, Dolores, Garfield, Mesa, Moffat, Montezuma, Montrose, Rio Blanco, San Miguel
	Nevada	Elko, Esmeralda, Eureka, Lincoln, Mineral, Nye, White Pine
	New Mexico	San Juan
	Utah	Beaver, Box Elder, Cache, Carbon, Duchesne, Garfield, Iron, Juab, Kane, Millard, Piute, San Juan, Sanpete, Sevier, Tooele, Uintah, Washington, Wayne

High Plains Subregion: A group of High Plains counties east of the Rocky Mountain chain in western Colorado, western New Mexico, and central Wyoming were used as a separate subregion in the regional impact analysis. With the exception of the areas north and south of the Platte River irrigation project, the subregion's economy is based primarily on ranching. Wyoming and New Mexico have substantial interest in the energy economy, with oil, gas, and coal being recovered in Wyoming and oil and gas being recovered in New Mexico.

Rocky Mountain Subregion: Counties in the central section of Western's affected area were combined to form the Rocky Mountain Subregion. The subregion varies in width and stretches from north-central Wyoming, through western Colorado, and into New Mexico. This area is sparsely populated, and the economy is based primarily on recreation and tourism, although historically, development has been based on the timber and minerals (hard metals) industries. Topographic features and poor proximity to urban markets have limited further development. A significant proportion of the land surface in the subregion is owned or administered by U.S. government agencies.

Great Basin Subregion: Between the Rocky Mountains to the east and the Sierra Nevada range in eastern California is a region of high desert, including western Wyoming and all of Utah, Arizona, and Nevada. The geographic distribution of water resources has

determined the location and level of economic activity in much of this area, and the main centers of population have grown largely in response to man-made changes in regional hydrological systems, particularly in southwestern Nevada and in central and southwestern Arizona. The majority of agricultural activity is located close to the urban centers in Maricopa and Pinal counties in Arizona, with a smaller concentration in Clark County, Nevada. The agricultural sector is highly capital intensive, with employment in that sector making up less than 1% of total county employment in the majority of counties. Tourism and recreation have become significant parts of the subregion's economy, with both mountain-based and water-based activities. As is the case with the Rocky Mountain Subregion, a significant proportion of the land surface in the Great Basin Subregion is owned and/or administered by U.S. government agencies.

A.5.3 Specification of Data for Input to the REMI and IMPLAN Models

The regional economic analysis used changes in retail prices and expenditures on electricity at the level of the individual customer utility and converted these changes to changes at the subregional level. This procedure involved calculating the proportion of power sales to industrial, commercial, and residential customers coming from Western and from other, non-Western sources for each county in the affected region. Shares at the county level were then aggregated to the subregional level to give the proportion of electricity sales coming from Western for each of the subregions. Based on these shares, changes in prices and expenditures on electricity for each customer class were calculated and used as inputs to the REMI and IMPLAN models. The impact of each commitment-level alternative on the cost of doing business in each subregion was estimated by changing commercial and industrial electricity rates. The impact of each alternative on the consumer price index (CPI) was estimated by calculating the change in residential expenditures (real disposable income) resulting from changes in residential electricity rates. The impact of each commitment-level alternative on the distribution of income among households in each subregion was estimated on the basis of the change in total expenditures on electricity in each subregion. Aggregating price and expenditure changes to the subregional level typically meant that the resulting price changes were significantly smaller than those at the individual utility or county level.

In addition to impacts that arise from changes in electricity prices and expenditures arising from each commitment-level alternative, secondary impacts on other industries in each subregion also arise from changes in the source of electricity supplies. However, although the impacts of expansion in production to meet the shortfall in Western electricity production in each subregion lead to gains in GRP, disposable income, employment and population, the size of the increase in electricity output needed to offset the shortfall in supplies from Western means that these impacts are relatively small. Analysis of impacts arising from changes in non-Western electricity production in each subregion shows that these impacts only partially offset impacts resulting from increases in the level of prices in each of the subregions. The measurement of impacts emanating from changes in electricity prices in each of the subregions used in the EIS therefore overestimates the size of these impacts.

A.6 RECREATION ANALYSIS

This section describes the methods used to assess the economic effects of the operational scenarios at Glen Canyon Dam and Flaming Gorge Dam on recreation and nonuse values. The analysis is based on the assumption that a change in streamflows could alter the quantity and quality of recreational activities at a site.⁵ Instream flows are a major determinant of the quality of boating and angling, and therefore the benefits received by recreationists. It follows that the amount of revenues received by many recreation-related businesses, such as commercial outfitters that offer white-water boating trips and angling guide service, could also be influenced by instream flows. In addition, there is the potential for effects on nonuse benefits, that is, benefits accruing to individuals who do not directly use the hydro resource but nonetheless attach a positive value to its existence. A more detailed description of the methods, underlying theory, and empirical results is presented in Carlson (1994).

A.6.1 Underlying Theory

According to the theory of welfare economics, the gross benefits (measured in monetary terms) derived from a good (or service) are measured by the aggregate willingness to pay for the good. Willingness to pay can in turn be divided into two components: (1) actual expenditures on the good, and (2) any additional amount individuals would pay for the continued right to consume the quantity in question. This latter amount, which is equal to the difference between total willingness to pay and actual expenditures, is called surplus value or "consumer surplus."⁶

When the potential impacts of a policy are viewed from the national level, the change in surplus values attributable to the policy question is the appropriate measure of the economic benefits. The change in surplus values, that is, consumer surplus, measures the amount by which individuals are better (or worse) off as a result of the policy. When the benefits of a policy option are assessed at the local economy level, expenditures become the focus of the analysis. In particular, the analysis addresses the effects of a change in expenditures on the levels of income and employment in the regional economy. One of the primary underlying assumptions of regional economic analysis is that changes in expenditures result in changes in income and employment. The link between expenditures on the one hand, and income and employment on the other, is known as the multiplier

⁵ This assumption is supported by the results of a number of recent studies. See, for example, Bishop et al. (1987), Walsh et al. (1980), and the review by Shelby et al. (1992).

⁶ Note that consumer surplus is not the same as "net benefits" except under certain conditions. Defining net benefits as gross benefits minus total variable costs, consumer surplus is that portion of net benefits that accrues to consumers. The remaining portion of net benefits accrues to producers in the form of "producer surplus" — the amount by which total expenditures exceed total variable costs. For a more detailed theoretical discussion of consumer surplus and the factors that cause consumer surplus to change, see Carlson (1994).

process. According to the theory of the multiplier, a change in spending in the local economy will result in a change in income that is some multiple of the initial spending change.⁷

In this analysis, the term "total value" is used to describe the total amount individuals are willing to pay for a resource of a given quality.⁸ The total value of a natural resource can be decomposed into two principal components: use value and nonuse value. The term "use value" refers to the value of the direct (and sometimes indirect) uses to which a resource can be put. The use values of a resource are measured by consumers' total willingness to pay — that is, the sum of expenditures and surplus values. Surplus value can also be thought of as net use value.

Nonuse values include what have been termed "existence value" and "bequest value." As its name suggests, existence value measures the value an individual attaches to the existence of a resource, whether or not the individual ever intends to use the resource personally. In the present case, it is plausible to assume that some individuals would be willing to pay a positive amount of money simply to know that the Grand Canyon — as well as other similar sites — would continue to exist in their current condition. In particular, individuals may attach positive values to the preservation of the existing ecology, historic and prehistoric artifacts and sites, and the current quality of recreational opportunities, to name but a few possibilities. In a similar vein, individuals may attach a positive value to the preservation of such resources for future generations. This type of value is called bequest value. In this case the distinguishing factor is the time frame.

Some disagreement exists among economists regarding the legitimacy of nonuse value as a value distinct from use value. For example, Brookshire et al. (1986) argued that although existence values may exist, they should nonetheless be excluded from benefit-cost analyses since they reflect considerations other than the efficiency motive. More recently, Rosenthal and Nelson (1992) and Quiggin (1993) have argued that although nonuse values may exist, they present a number of problems that raise serious questions about the legitimacy of including them in the decision-making process.

Proponents of the case for the inclusion of nonuse values in total valuation studies, however, have offered strong rebuttals to the arguments described above. For example, a report prepared by HBRIS, Inc. (1991, p.17) contends that:

Motives based on feelings of environmental responsibility have to do with people's concerns about the effects of their consumption on environments that they do not personally plan to use. For example, if Gamma's consumption of electricity would contribute to deterioration of Grand Canyon Beaches, then she might be willing to pay something to reduce or eliminate

⁷ A more detailed discussion of the multiplier process is presented by Carlson (1994).

⁸ As a result of its focus on willingness to pay, total value is associated with national benefits, as opposed to regional benefits.

this effect so that she is not responsible for such harm. Bequest motives are a temporal extension of motives relating to benevolence toward relatives and other people in the temporal realm.... If the benefactor's utility depends on the bequest, an additional value is created, and this additional value is missed if the beneficiary's use value alone is included in benefits.

As the preceding discussion suggests, there are strong arguments both for and against including nonuse values in a total valuation study.

A.6.2 Estimation Techniques

Regional or local economic impacts are usually estimated with the use of an input-output model. For example, the regional economic impacts of a change in Western's commitment-level alternatives were estimated with the REMI Model (Section A.5). The analysis of the regional effects of recreation below Flaming Gorge Dam were estimated with the IMPLAN regional economic model. Regional economic impacts associated with recreation at Glen Canyon Dam were based on results reported in the Glen Canyon EIS (Reclamation 1993). A complete discussion of the IMPLAN model and the analysis of recreation below Flaming Gorge Dam is presented in Rose and Frias (1993a). The principal results of their analysis and the implications for the operational scenarios at Flaming Gorge Dam are summarized in Sections 3.1.1 and 4.1.1.

With respect to the estimation of use values, an approach that has received increased attention in the literature is that of "benefits transfer." As its name implies, benefits transfer entails the use of existing estimates of benefits at one site, commonly referred to as the "study site" to estimate the benefits of recreation at some other site, referred to as the "policy site."⁹ Thus, the Green River below Flaming Gorge Dam is a policy site. Because it has been the subject of a number of previous studies of the economic benefits of recreation, the area below Glen Canyon Dam is both a policy site and a study site.

Benefits transfer can be more or less rigorous depending upon the available data and the needs of the policy analyst. For example, in some situations benefits transfer amounts to the development of rough estimates based on averages from previous studies. This type of approach would be acceptable in cases where the analyst requires a "ballpark" figure to determine whether further analysis is warranted. In other cases, provided that sufficient information is available, empirical relationships estimated in previous studies may be applied to the site in question to generate estimates of consumer surplus. Once again, the choice of whether to use this approach depends upon the needs of the analyst and the amount of available information. These issues are addressed in more detail by Carlson (1994).

⁹ The distinction between the terms "study site," which refers to the recreational resource for which benefits have been previously estimated, and "policy site," which refers to the site for which benefits estimates are needed was first introduced by Desvousges et al. (1992). This distinction will be employed throughout the remainder of the discussion presented here.

As is discussed below, a benefits assessment of recreation below Glen Canyon Dam was completed by Bishop et al. (1987) as part of the Glen Canyon Environmental Studies. The results of that study were incorporated directly into this EIS. However, in light of time and budget constraints that were imposed on this analysis, the benefits of recreation below Flaming Gorge Dam were estimated by the benefits transfer process. To complete the benefits transfer, studies had to be identified, assessed, and (where appropriate) summarized for use in this process. For the reasons discussed in Section 3.7, the analysis was confined to angling and white-water boating. Although a number of studies were identified as potential candidates for the benefits transfer in the initial screening process, most of them were eliminated for various reasons (Carlson 1994). Two studies emerged as potential candidates — a study by Walsh et al. (1980) and the study by Bishop et al. (1987).

The study by Walsh et al. (1980) examined recreational activities (including fishing, kayaking, and rafting) on nine rivers in western Colorado. In addition to estimating the effects of congestion on the demand for individual activities, the authors also estimated the relationship between changes in streamflow, measured as a percent of bank-full conditions, and the average consumer surplus per day for each activity. Given the proximity of the study sites to the policy sites being considered here and the types of questions that were addressed, the Walsh et al. (1980) study would appear to be a good candidate for use in a benefits transfer. However, the fact that the benefit estimates were conditioned on the optimal amount of congestion per stream mile would make transfer of the estimates to Flaming Gorge extremely difficult. This difficulty results from the lack of information on what would constitute the optimal concentration of anglers and white-water boaters along the Green River. Given this lack of information, it would not be possible to determine the likely direction of bias in the resulting estimates.

Bishop et al. (1987) conducted an attribute survey and contingent valuation (CV) survey of anglers, white-water boaters, and day rafters on the Colorado River below Glen Canyon Dam. The purpose of the surveys was to identify the aspects of angling and white-water boating that are most likely to influence the net benefits from the experience, and to derive estimates of the benefits derived from angling, white-water boating, and day rafting under different dam operational scenarios. According to the results of the attributes survey and CV survey that followed, the benefits of day rafting between the dam and Lees Ferry are largely unaffected by changes in streamflows. It was concluded, therefore, that the use value of day rafting on this stretch of the river would not change with a change in dam operations.¹⁰

For multiple-day white-water boating trips, the attributes survey revealed that boaters tend to prefer constant flows to fluctuating flows, since the former is more consistent with natural conditions. In addition, if flows are constant, higher flows are preferred to lower flows over the range of 1,000 cfs to approximately 33,000 cfs (commercial boaters) and 29,000 cfs (private boaters). In the case of fluctuating flows, higher flows are preferred to

¹⁰ Note, however, that a change in the number of people participating in day rafting would nonetheless cause the aggregate net benefits from this activity to increase or decrease.

lower flows over the range from 5,000 to 25,000 cfs for both groups. The attributes survey revealed that anglers also prefer constant flows to fluctuating flows, since the former are more consistent with natural conditions. In addition, higher flows are preferred to lower flows over the range of 1,000 cfs to approximately 10,000 cfs for both constant and fluctuating flows.

Estimates of surplus value associated with various flow levels and assumptions about fluctuations in flows were developed from results of the CV survey. These estimates were then used to construct "flow valuation curves" that relate surplus values to flow levels. Separate flow valuation curves were constructed for commercial white-water boating, private white-water boating, and angling for both constant and fluctuating flows, (i.e., a total of six flow valuation curves were constructed). These curves were then used to estimate the recreation benefits associated with different operational scenarios and hydrological conditions at Glen Canyon Dam. These curves were subsequently modified by ANL to estimate the benefits from recreation below Flaming Gorge Dam.

Although the study by Bishop et al. (1987) was selected as the best candidate for benefits transfer, several potential sources of bias exist. First among these is the fact that part of the use values attributed to recreation below Glen Canyon Dam may reflect the unique scenic beauty of the area. Although the Green River and surrounding environment below Flaming Gorge Dam are also considered to be quite scenic, it is nonetheless possible that the difference between the two sites results in an upward bias in the estimates of the value of recreation below Flaming Gorge Dam. Another source of bias is the assumption of constant use rates. To the extent that use rates actually increase or decrease with change in flows, benefits estimates would be either downward or upward biased. This observation applies equally to the benefit estimates for both sites.

In order to conduct the benefits transfer, some of the flow valuation curves developed by Bishop et al. (1987) had to be modified before they could be transferred to the Flaming Gorge site. Modification was required because of the significant difference in flow regimes at the two sites, and in light of information on individual preferences for flows at Flaming Gorge. In the case of angling, benefits are maximized at flows of 10,000 cfs below Glen Canyon Dam. However, in the case of Flaming Gorge Dam, as is discussed in Section 3.7, angling satisfaction is at a maximum when flows are between 1,100 cfs (shore anglers) and 1,500 cfs (boat anglers). Consequently, the flow valuation functions had to be scaled to reflect the range of preferred flows at Flaming Gorge.¹¹ The resulting modified value functions were then combined with data on use rates and monthly average flows below Flaming Gorge Dam to obtain the estimates presented in Section 4.2.1.2. In the case of the white-water boating flow valuation curves, the functions were not modified. Instead, the functions developed by Bishop et al. (1987) were combined with use rates and flows to estimate the value of white-water boating in Dinosaur National Monument. This approach was based on

¹¹ The details of the scaling procedure and the modified flow valuation functions are described by Carlson (1994).

the similarity of the minimum flows at the two locations (1,000 cfs at Glen Canyon and 800 cfs in Dinosaur National Monument) and the lack of information suggesting that the flow level at which use values are maximized differed substantially across the two locations.

With respect to nonuse values, previous research suggests that nonuse values may account for a substantial portion of the total value of a resource. For example, Fisher and Raucher (1984) reviewed a number of studies that estimated use and nonuse values of particular resources. They concluded that "non-use benefits generally are at least half as great as recreational use benefits (p. 60)." As was noted in Section 3.1.2, a study by Loomis (1987) estimated that nonuse values were approximately 73 times as large as the corresponding use values associated with Mono Lake in California. This broad range indicates both the potential magnitude of nonuse values and difficulties that would be encountered in attempts to estimate nonuse values on the basis of existing studies. In light of the considerable variability in existing estimates of nonuse values, and the lack of information on the effect different operational scenarios could have on such values, no empirical estimates were attempted. Instead, observations on the potential effects on nonuse values were confined to qualitative assessments.

A.7 IRRIGATED AGRICULTURE

This section describes the method that was used to estimate the impacts of the commitment-level alternatives on agricultural output in selected states. A more detailed description of the analysis and empirical results see presented by Flaim et al. (1994).

A.7.1 Introduction

The irrigated agriculture impacts analysis is based on the assumption that within the agricultural sector, farmers are able to choose from a large number of crops. Moreover, the farmers have alternative means of producing each crop. At the broadest level, the farmers can choose between cropping practices — irrigated versus dryland agriculture — and for each of these practices can choose levels of other inputs, such as fertilizers, pesticides, capital equipment, and management labor. In the case of dryland cropping, farmers rely on rainfall for water and choose crops, acreage, and other inputs accordingly. For irrigated cropping practices, farmers can purchase surface water or they can pump groundwater. Pumping groundwater requires power to operate the pumps; for most farms that power is electricity. For the region under consideration in this analysis, electricity is used to power nearly 80% of all irrigation pumps. Natural-gas- and diesel-powered irrigation pumps make up most of the remaining 20%. As a result of these options, a change in electricity prices implied under different commitment-level alternative/supply option combinations can trigger a broad set of responses by farmers as they attempt to maximize profits. The approach taken in this analysis was to capture the full range of options at the disposal of farmers. In particular, the approach emphasized the substitution between inputs and acreage across cropping practices that typify the farmer's resource allocation decision.

A.7.2 Scope of Analysis

The analysis was performed for each of six states (Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming). The analysis concentrated on field crops (barley, corn, silage, cotton, hay, sorghum, and wheat) and allowed for both irrigated and dryland cropping, depending on the extent to which irrigated and dryland cropping practices are combined in each state. The data used to determine baseline values of acreage, outputs, water use, energy inputs, and input costs were taken from individual state agriculture publications and U.S. Department of Agriculture (USDA) publications. The baseline price forecasts were taken from a recent USDA forecast of crop prices. The most recent year for which most of the required data were available was 1990, so that was used as the test year for purposes of constructing the baseline. Forecasted acreage for each crop in each state was then determined from the USDA forecasts of national level acreage. As the baseline was constructed, it was assumed that the basic technology of farming was fixed; for example, yields per acre and water application rates (acre-feet per acre of water) for all crops were assumed not to change over the 1993-2008 forecast period. In effect, this amounts to assuming no fundamental changes occur in agriculture technology. Innovations such as higher-yield seed, more efficient groundwater pumping, and changes in the efficiency of specific irrigation practices (e.g., drip irrigation) were ruled out.

A.7.3 Method of Analysis

The analysis relied on the method of positive mathematical programming (PMP), which combines linear with nonlinear programming techniques. This approach involves two stages. The first, or calibration, stage solves a linear program of agriculture activity. This stage accomplishes two tasks. First, the model is calibrated to actual baseline data. Second, the opportunity costs of the resources used are determined. The nonlinear programming problem solved in the second stage determines the optimal mix of inputs. Given the optimal input mix that includes acreage for each crop by cropping practice, the optimal set of outputs of each crop is determined. For this analysis, the results of the first (linear programming) stage were calculated under the assumption of no change in electricity costs for groundwater pumping and, hence, represented the baseline simulation. The second stage (nonlinear programming) incorporated the change in electricity prices under the different commitment-level alternative/supply option combinations. The impacts were then determined by comparing the results of the analysis under this second stage to the baseline results.

This analysis permits a broad set of substitution possibilities. First, crops could be switched between practices (i.e., between dryland and irrigated agriculture). Within irrigated agriculture, farmers could switch crops between pumped irrigated and surface water acreage. Within pumped irrigation, farmers could switch between fuels (e.g., between electricity, natural gas, and diesel, and other fuels). For purposes of this analysis, nonelectric fuel sources (e.g., natural gas, diesel, LP gas, gasoline and gasohol) were aggregated into one groundwater pumping energy source identified as "other." In addition, farmers could also alter fertilizer, pesticide, and capital usage. All of these substitution possibilities are captured in a constant elasticity of substitution (CES) production function broken into nests

that reflect these different levels of substitution. For this analysis, two large nests were assumed. The first was for dryland farming, which broke input use into two broad categories (land and variable inputs). The variable input nest was then assumed to depend on three inputs (capital, chemical, and other). The second nest was for irrigated cropping practices. Production in this nest was broken into three groups (land, variable inputs, and water). The variable input nest included capital, chemical, and other inputs. The water input nest included surface water, groundwater electric, and groundwater other.

The principal input decision for a farmer is acreage allocation between crops. Once that decision is made, the other input allocations will closely follow suit (i.e., will be roughly proportional to the acreage decisions and other input requirements for each crop). Higher electricity prices make the electrically irrigated acreage more expensive relative to other acreage. This situation can lead farmers to switch to less water intensive crops or can cause farmers to move less profitable crops away from electrically irrigated acreage towards nonelectrically irrigated acreage, surface water acreage, or even to dryland farming. The detail in the approach taken in this analysis made it possible to estimate the role played by all of these impact channels in a farmer's resource allocation decision.

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