Energy Planning and Management Program Environmental Impact Statement
DOE/EIS-0182

Western Area Power Administration

Energy Planning and Management Program

Environmental Impact Statement

COVER SHEET

Title: Energy Planning and Management program

Agency: Western Area Power Administration

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ABSTRACT

This environmental impact statement contains an analysis of the anticipated environmental impacts that would result from Western's proposed Energy Planning and Management program. it contains a total of 13 alternatives, including a No-Action Alternative. All but the No-Action Alternative comprise different approaches to implementing the proposed Program. Except for the No-Action Alternative, relatively small distinctions were found in the impacts expected to result from the alternatives. However, there are important differences between the No-Action and other alternatives. The findings suggest that, in comparison with the No-Action Alternative, any of the Program Alternatives would result in fewer adverse environmental impacts over time. The analysis of economic impacts found that, in comparison to No-Action Alternative, the Program Alternatives would be neutral or could improve regional economies.

Western has established a Preferred Alternative that falls within the range of activities and impacts associated with the Program Alternatives. The Preferred Alternative is treated as a combination of Alternative 5 and 6 and is not addressed separately.

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CHAPTER 1 Introduction

1.1 PURPOSE AND NEED STATEMENT

The Western Area Power Administration (Western) needs to encourage long-term energy management planning by its customers. Due to the impending expiration dates of its existing long-term firm power sales contracts, and the considerable lead time necessary for existing customers to develop alternate resources if existing commitments are not extended, Western needs to place power under contract so its customers can plan for the future. Contract expirations present an opportunity to restructure Western's marketing approach to facilitate long-term energy management planning by Western's customers.

The purposes of the proposed Energy Planning and Management Program (Program) are to:

* Promote the stable, efficient, and economical use of electrical generation and conservation resources by Western's customers.
* Promote consideration by Western's long-term firm power customers of cost-effective, demand-side management and supply-side alternatives including renewable resources, as part of their long-term planning processes.
* Market Federal power on a long-term basis in accordance with Western's mission as a power marketing administration.
* Develop the Program in an equitable manner consistent with Western's legal obligations and constraints, including the obligation to carry out Section 114 of the Energy Policy Act of 1992 (the Act).

1.2 BACKGROUND FOR DEVELOPING THE PROPOSED PROGRAM

Western is an agency of the U.S. Department of Energy (DOE) charged with marketing and transmitting Federally produced electricity throughout a 1.3-million-square-mile geographic area. Western's service region covers 15 states from Minnesota in the northeast to California in the southwest.

The majority of Western's electricity comes from Federally owned and operated hydroelectric plants. Western currently markets its long-term firm hydroelectric power resources on a project-specific basis. Contracts for these resources expire over the next several years. For example, commitments to customers purchasing power from the Pick-Sloan Missouri Basin Program-Eastern Division will expire in the year 2000, while contracts for the sale of power from the Loveland Area Projects will expire in the year 2004.

The electricity marketed by Western is generated by separate Federal water development projects, many of which have multiple generating facilities. Each of these projects has different enabling legislation, and separate repayment requirements and contracts. Some of these projects have been integrated administratively by Western for contracting and rate purposes.

On November 13, 1981 (46 Federal Register [FR] 56140), Western published its initial Guidelines and Acceptance Criteria (G&AC). These criteria provided for the development and implementation of customer Conservation and Renewable Energy (C&RE) Programs for all power customers who purchased long-term firm Federal power. The original G&AC were developed pursuant to Western's authority under the Department of Energy Organization Act of 1977 (42 U.S. Code [USC] 7152 and 7191), and under the Reclamation Law approved June 17, 1902 (32 Stat. 388) and subsequent amendments and supplements, in particular Section 9(c) of the Reclamation Project Act of 1939 [43 USC 485h(c)]. A penalty provision for noncompliance with the G&AC was included in long-term contracts as opportunities arose. The penalty provision stated that those who do not comply with the G&AC may be subject to a 10-percent reduction in their Western power contract commitments.

Legislation specifically authorizing Western's C&RE Program was included in Title II of the Hoover Power Plant Act of 1984 (42 USC 7275-7276). After this legislation was passed, an amendment to the G&AC was issued on August 21, 1985 (50 FR 33892) establishing new G&AC and review criteria. The amended C&RE program is described in Chapter 2.

A more recent review of Western's G&AC, initiated by 17 public meetings held throughout Western's service area in the spring of 1990, indicated that it could be measurably improved by strengthening some provisions and incorporating a more comprehensive approach than that currently taken by Western's C&RE program.

Western also is facing the expiration of many of its long-term firm power contracts over the next several years. These contracts present an opportunity to restructure Western's marketing approach to facilitate long-term energy management planning by Western's customers.

On April 19, 1991, Western formally proposed the Program, which featured linkage of Western's power resource allocations with long-term energy planning and Western's customers' efficient energy use through the preparation of integrated resource plans (IRPs) (56 FR 16093). Western also provided notice to the public of its intention to prepare an environmental impact statement (EIS) on the Program (56 FR 19995 [May 1, 1991]). Notice of the availability of the draft EIS for public comment was published on March 31, 1994 (59 FR 15198). Eight public hearings on the draft EIS were held throughout Western's service territory in April and May of 1994. The proposed program was published on August 9, 1994 (59 FR 40543). A 90-day comment period followed, with seven public meetings held in six western states. Western has developed the Program through an extensive public participation process, including 53 public meetings and workshops and distribution of a series of Program newsletters. All comments received on the draft EIS were considered. Appropriate changes were incorporated in this text. A summary of the comments received and Western's responses is found in Appendix G.

On October 24, 1992, the Energy Policy Act of 1992 (Public Law No. 102-486) was signed into law. Section 114 of the Act amends Title II of the Hoover Power Plant Act of 1984, and requires Western's customers to submit and implement IRPs. Much of this legislation is consistent with and reinforces Western's ongoing administrative development of the Energy Planning and Management Program. At the time the Act was signed into law, this EIS was being prepared and a notice of its availability was being developed for publication in the Federal Register. Changes to Western's Program resulting from passage of the legislation include an adjustment to the penalty provision and a requirement that Western penalize customers not acting in accordance with their IRPs. This EIS recognizes and incorporates the Act into the Program Alternatives.

Section 114 of the Energy Policy Act of 1992 specifies that the National Environmental Policy Act of 1969 (NEPA) shall apply to the Administrator's actions implementing integrated resource planning. This EIS complies with that mandate.

Western recognizes that many of its customers have already engaged in beneficial conservation and demand-side management (DSM). IRP offers the opportunity to structure future investments in these areas to help ensure their cost efficiency. Western has prepared a Resource Planning Guide, an IRP technical assistance tool, which is available for customers as they develop least cost resource options for the future.

1.3 PROPOSED PROGRAM

Western proposes to establish an Energy Planning and Management Program to replace its G&AC for the C&RE Program and to make decisions concerning future resource commitments to existing customers. If adopted, the proposed Program would require Western's long-term firm customers to implement long-term energy planning to help achieve efficient electric energy use. The proposed Program could link Western's power resource allocations to customer programs for long-term energy planning and efficient electric energy use, or power could continue to be marketed on a project-specific basis in the future.

The two parts of the proposed Program are the Power Marketing Initiative (PMI) and the Intergrated Resource Planning (IRP) provision. Under the proposed PMI, three different groups of alternatives have been developed. All of the alternatives, except the No-Action Alternative, include the penalty provision of the Energy Policy Act of 1992. The groups of PMI options considered in this EIS are:

* PMI Extension Alternatives - The first group, known as the PMI extension alternatives, would give Western's existing customers relatively long-term extensions of a major percentage of the Federal power resource currently committed to them subject to certain provisions. These provisions include the percentage of the allocation, the term of the contracts, establishment of a resource pool, and the manner in which the pool would be

used. Contracts for resource extensions would be signed upon receipt of a customers initial IRP by Western.

* PMI Limited Extension Alternatives - The second set, known as the PMI limited extension alternatives, would extend resources for 10 years from the date of IRP approval, a relatively short time period. This short extension period is intended to provide Western's existing long-term firm power customers with a term adequate to facilitate the development of an IRP and effectuate associated action plans. The extension would act as a bridge to give Western time to develop project-specific marketing plans and the customers time to develop and implement alternative resources in reaction to any change of marketable resources as identified in the project-specific marketing plan. Contracts for resource extensions would be signed upon approval of a customer's initial IRP by Western.
* PMI Non-Extension Alternatives - The third set, known collectively as the PMI non-extension alternatives, would not feature any marketing of resources under the proposed Program. Customer integrated resource planning would take place in accordance with the Energy Policy Act of 1992, and marketing criteria would be separately developed on a project-specific basis.

Coupled with each PMI option, the EIS analyzed two IRP policy options: IRP for all long-term firm power customers, and adoption of a small customer exception in accordance with Section 114 of the Energy Policy Act of 1992.

Western must place its resources under contract to fulfill its mission as a power marketing administration, to repay each project's debt, and to provide its customers with resource certainty. Western's utility customers have the responsibility to meet the electricity needs of their consumers, which means the utilities must guarantee electric service. Quality utility planning is enhanced when a customer's existing power resources are stable and reliable. To be considered a stable and reliable part of a customer's existing resources, Western's power allocation must be secure over a time frame typical of long-term firm power sales and purchases in the utility industry.

The proposed IRP provision would require each customer to establish an energy management program, which would be applicable to all customer power resources and not just the Western allocation. Customer activities that may fall under the Program Alternatives (see Chapter 2) include IRP or activities appropriate for certain small customers with limited resources. At an earlier stage in this public process, Western also considered a performance plan option. Due to passage of the Energy Policy Act, a performance plan is no longer a viable option and is no longer under consideration.

The No-Action Alternative describes Western's current power marketing approach and the most recent provisions of the C&RE Program. For purposes of analysis, this EIS assumes an extension of existing power contracts without change for a time period comparable to the terms of power contracts currently in effect to provide a baseline for comparing alternatives. Western recognizes that the existing power contracts would eventually expire, requiring some action in the absence of this Program. However, in order to provide a meaningful comparison between the Program Alternatives and existing conditions, extensions of present contracts were assumed.

CHAPTER 2 Alternatives Including the Preferred Alternative

2.0 ALTERNATIVES

Western has proposed a two-part Program that considers tying the allocation of Western's electric resources to long-term customer resource planning and the efficient use of electric energy. Potential Program components have been combined to form 13 alternatives which are described in this chapter. A No-Action Alternative, based on pre-existing program features, is included in the 13 alternatives. The Preferred Alternative, identified as Alternative 13, is similar to the provisions of Alternatives 5 and 6.

The two parts of the proposed Program are the PMI and the IRP provision. Under the PMI, Western could give existing customers extensions of a major percentage of the Federal power resource currently committed to them with certain provisions. These provisions include the percentage of the allocation, the term of the contracts, establishment of a resource pool, the manner in which the pool would be used, and penalties for noncompliance. If no extension were offered, Western would market its resources on a project-specific basis.

The IRP provision would require customers to establish an energy management program, which would be applicable to all customer power resources and not just the Western allocation. Customer activities evaluated for inclusion within the IRP provision include IRP, or activities appropriate for certain small customers with limited resources. At an earlier stage in this public process, Western also considered a performance plan option. Due to passage of the Energy Policy Act, a performance plan is no longer a viable option and is no longer under consideration.

The PMI and IRP provision are each made up of several components. These components have been packaged in different combinations to form the alternatives described in this chapter. The No-Action Alternative describes Western's amended C&RE program. A description of the derivation of the range of alternatives can be found later in this chapter.

This chapter first describes the different components that make up the alternatives considered. Many public comments received during the Program development process were integrated into the alternatives. Next, options that have been proposed by the public but that have not been incorporated into the Program Alternatives are addressed. This chapter then describes how alternatives were grouped for comparison. Lastly, this chapter summarizes the environmental impacts of the alternatives, which are discussed in detail in Chapter 4.

Since publishing the draft EIS, Western has chosen a Preferred Alternative. The Preferred Alternative is made up of the same type of components described in section 2.1. The Preferred Alternative is similar to the provisions of two existing Alternatives 5 and 6. The new Alternative tends to resemble a combination of these Alternatives. The two existing Alternatives establish a narrow range of activities in which the Preferred Alternative would reasonably fit. Because of its similarity to existing Alternatives, and the ability to distinguish the impacts of the Preferred Alternative by interpolating between the existing Alternatives, additional analysis was not completed for the Preferred Alternative. The Preferred Alternative is described in section 2.4.5.

2.1 COMPONENTS OF PROGRAM ALTERNATIVES

This section describes the components that make up each of the alternatives considered in this EIS.

2.1.1 Integrated Resource Planning Provision

The objectives of the IRP provision are to encourage Western's customers to make energy management improvements and consider DSM practices to ensure that electrical power is used in an economically efficient and environmentally sound manner. The IRP provision would also support and promote cost-effective development of renewable resources by Western's customers to meet future energy needs.

Two IRP provision components are considered, in addition to the No-Action Alternative, as part of the alternatives. These components include IRP and activities appropriate for certain small customers with limited resources. These options were thoroughly explored during extensive public involvement conducted prior to the preparation of this EIS. IRP provision requirements would apply to all of Western's long-term firm customers.

2.1.1.1 Integrated Resource Planning

As defined in the Act, IRP is a planning process for new energy resources that evaluates the full range of possible alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to electric customers. IRP is the focus of the IRP provision of Western's Program, and is now required by Section 114 of the Act. Electric utilities have been engaged in planning to meet the needs of their customers for many years. However, IRP expands the scope and nature of the planning process and the subject of the analysis. At utilities already employing IRP, the scope of planning has expanded to consider energy-efficiency and load management programs as resources, the environmental aspects of energy production, and a variety of resource selection criteria beyond electricity price (Hirst, Goldman, and Hopkins 1990). Table 2.1 compares the differences between traditional planning and IRP.

Table 2.1 Differences Between Traditional Planning and Integrated Resource Planning

Traditional Planning	Integrated Resource Planning
Focus on utility-owned central station power plants	Diversity of resources, including utility-owned plants, purchases from other organizations, conservation and load management programs
Planning internal to utility, often primarily in system planning and financial planning departments	Planning spread among several departments within utility and involves customers, public utility commission staff, and non-utility energy experts
All resources owned by utility	Some resources owned by other utilities, by small power producers, by independent power producers, and by customers
Resources selected primarily to minimize electricity prices and maintain system reliability	Diverse resource-selection criteria, including electricity prices, revenue requirements, energy-service costs, utility financial condition, risk reduction, fuel and technology diversity, environmental quality, and economic development.

Source: Hirst, Goldman, and Hopkins 1990

Under the proposed Program, Western would accept IRPs from individual customers or the member-based association (MBA) to which they belong. IRPs prepared for other governmental agencies would be acceptable as long as they meet Western's criteria. Western also may allow customers to join together to prepare and submit joint IRPs. Western's acceptance would be based on adherence to the planning process and inclusion of defined contents and elements. The size and complexity of individual IRPs would vary depending on customer size, type, and demographic nature. IRPs must contain goals, schedules, expected quantifiable benefits, milestones, and expenditures. The IRPs would apply to all customer resources, not just those purchased from Western. An updated submittal would be required every five years. The following seven elements are Western's requirements for a well-developed plan, as set forth in the Act:

1) Identify and accurately compare all practicable energy efficiency and energy supply resource options available to the customer.
2) Include a two-year action plan and a five-year action plan which describe specific actions the customer will take to implement its IRP.
3) Designate least-cost options to be utilized by the customer for the purpose of providing reliable electric service to its retail consumers and explain the reasons why such options were selected.
4) To the extent practicable, minimize adverse environmental effects of new resource acquisitions.
5) In preparation and development of the plan (and each revision or amendment of the plan) provide for full public participation, including participation by governing boards.
6) Include load forecasting.
7) Provide methods of validating predicted performance in order to determine whether objectives in the plan are being met.

One of the IRP elements is the consideration of environmental effects of resource choices. To the extent practicable, customers must consider and document the environmental effects of resource options in their IRPs. The documentation could be quantitative and statistically based or the effects could be described qualitatively, depending on each customer's circumstances.

Western is not proposing to mandate that mathematically derived economic (dollars) or statistical values for environmental impacts be factored into resource decisions. Such an effort may not be reasonable, or provide useful information, for many customers. Nor is Western prohibiting a customer, if that customer chooses, from quantifying environmental impacts and considering such values in its IRP. Western is encouraging a level of effort commensurate with each customer's individual situation.

Externalities

Economists often refer to environmental impacts and costs not reflected in a transaction as externalities. As an economic term, externalities represent costs or benefits that are not priced in the marketplace (Baechler and Lee 1991; Baumol and Oates 1975). The persons, firms, or communities bearing the costs of externalities absorb them without compensation. For use in utility planning, Ottinger (et al. 1990) states that environmental externality costs are costs to society resulting from the provision of electric services, in addition to costs already incorporated in the price of those services. They are those costs that occur after all government-imposed environmental standards and regulations are met and control strategies are employed. Other names sometimes used for these costs are environmental costs, environmental damages, and damage costs.

Some states, utilities, and Federal agencies are incorporating costs for externalities into their planning processes. The costs of externalities are not directly passed on to utilities or consumers. For purposes of comparison and planning, the costs are added to the capital and operating costs of generation plants and demand-side programs. Certain States and utilities are currently using four approaches to valuing environmental externalities. These approaches are described below.

* Damage costs involve applying economic valuation techniques to estimate the costs of actual damages resulting from electricity generation. Three approaches to developing damage costs include quantifying the economic costs associated with each type of damage using econometric techniques such as contingent valuation and hedonic analysis (health effects, decreased visibility); determining the costs of mitigating the effects (developing a forest reserve to mitigate CO_2 emissions); and estimating the costs of controlling emissions (installing advanced pollution control equipment) (Buchanan 1990).
* The New York Public Service Commission has developed a statistical approach to assigning scores and weights to environmental impacts to air, land, and water (Baechler and Lee 1991; Putta 1990). Scores are assigned based on the magnitude of an impact or a qualitative measure of its severity. Weights depend on the relative cost of controlling or mitigating an attribute of the damage costs attributable to the impacts.
* Some States use a simple adder to account for the differences in externalities produced by different resources. With this approach a technology resulting in certain types of impacts, such as thermal plants that emit CO_2, has a percentage added to its estimated costs.
* Some States require regulated utilities to account for the costs of externalities, but do not prescribe a particular method.

The costs applied or suggested by different organizations are listed in Table 2.2. The costs presented are based on values for generic plants. These costs have been used in evaluating competitive bids for new generation proposals. Actual plants with specific emission estimates would likely result in different costs.

Western is not proposing to require the quantification of environmental externalities, with mandatory use of these values in customer resource decision-making, as part of the Program. Several reasons underlie this approach. First, this controversial issue is presently the subject of public debate and scientific analysis with no consensus being reached. Until this debate and analysis has been resolved, it would be premature to attempt to require Western's customers to calculate the cost of environmental externalities. Second, even with technical assistance from Western, Western's customers would find it very difficult to develop appropriate quantifications of the environmental impacts of the multitude of resources that they now use and plan to use in the future. Finally, the Act requires Western's customers to minimize adverse environmental effects of new resource acquisitions to the extent practicable and to provide reliable electric services which will, to the extent practical, minimize life-cycle system costs. This Congressional direction establishes an IRP review standard different from a mandatory environmental externality approach.

2.1.1.2 Other Planning Processes

Section 114 of the Act specifies that for certain customers with annual energy sales or usage of 25 GWh or less the Administrator may establish and apply different regulations if it is found that these customers have limited economic, managerial, and resource capability to conduct IRP. Such customers are required to consider all reasonable opportunities to meet their future energy service requirements using DSM, new renewable resources, and other low-cost programs that minimize, to the extent practicable, adverse environmental effects.

2.1.2 Power Marketing Initiative

The PMI features some alternatives that would extend commitments of a majority of Federal resources to existing customers under long-term firm contracts. The objective of these alternatives would be to foster customers' long-term resource planning and to promote overall electric resource efficiency by using Federal resources to encourage energy efficiency. An associated objective would be to streamline future Federal power marketing activities, including potential adjustments to marketable resources and possible withdrawals for defined purposes. Other alternatives feature a relatively shorter resource extension or would have Western market its resources on a project-specific basis in the future.

Western has combined the IRP and PMI components to form the range of alternative analyses in this EIS. Tables 2.4 and 2.5 summarize the various IRP and PMI components used for the analyses. Table 2.6 describes the alternatives developed from the components, including the Preferred Alternative.

Table 2.2. A Comparison of Externality Costs that Would Be Added to Other Resource Costs for the Competitive Acquisition of Firm Energy (1990 mills/kWh)

Resource Type	BPA[a]	Calif.	Mass.	Nevada	New York	Ottinger[b]
Pulverized Coal	5.1	83.1	46.5	45.4	9.1	39
Atmospheric Fluidized Bed Coal	3.0	29.3	28.9	27.8	3.3	28
Coal Gasification	2.5	21.0	25.7	27	2.5	25
Simple Cycle CT	1.5	28	22.4	21.8	3.4	
Combined Cycle CT	1.4	16.5	19	15	2.3	10
New Hydroelectric	2.0					
Natural Gas Cogeneration	1.2	10.8	9.8	9.5	1.5	
Existing Hydroelectric Additions	1.0					
Geothermal	1.0					
Wind	0.5	0-1				
Solar	1.0	0-4				
Conservation	0					
Wood-Fired Cogeneration	3.8	61.4	16.5	16.5	6.1	0-7
Municipal Solid Waste-						
Fired Cogeneration	7.9	127	26.3	26.3	9.9	
Nuclear	2.0	29				

BPA = Bonneville Power Administration
CT = combustion turbine
Source: Bonneville 1992 and Ottinger et al. 1990
a These are the current numbers; personal communication with Shep Buchanan, Bonneville Power Administration, October 11, 1994.

b Costs for this column only are in 1989 mills/kWh.

Table 2.3. Environmental Externality Values (1990 $/ton)

Source	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Methane	Particulates	Volatile Organics
Tellus Institute	1,560	6,800	24	240	4,180	5,540
Calif. Energy Comm.	18,140	9,300	8	80	12,220	5,220
New York DPS	860	1,920	1	0	340	0
So. Coast AQMD	78,400	274,000	0	0	46,000	30,400
PACE	4,240	1,720	14	0	2,480	0
Bonneville	400-3,600	60-800	6	0	160-1,600	0
Sweden	2,380	6,360	40	0	0	0
Oregon a	2,000-5,000	0	10-40	0	2,000-4,000	0
Minnesota b	0-300	68.80-1,640	5.99-13.60		166.60-2,380	1,180-1,200
Wisconsin c	0	0	15	150	0	0
Massachusetts c	1,700	7,200	24	240	4,400	5,900
Nevada c	1,644	7,166	24	232	4,406	1,244

a In 1993 $/ton; source; Public Utilities Fortnightly (1993).
b In 1994 $/ton; source; Public Utilities Fortnightly (1994); Alliance to Save Energy et al. (1992)
c Source: Northwest Power Planning Council (1994)

Table 2.4. Summary of the IRP Components Considered by Western

IRP Components

Integrated Resource Plan
IRP required for some or all customers. IRP is a process where supply-side and demand-side resource options are consistently evaluated together to determine how to serve the electricity needs of consumers at the lowest reasonable cost.

Other Planning Options
RP required for most customers, but Western would establish different regulations for certain small customers with total energy sales or usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility. These customers shall consider all reasonable opportunities to meet future energy services requirements using demand-side techniques, new renewable resources, and other programs that provide retail customers with electricity at the lowest possible cost, and minimize, to the extent

practicable, adverse environmental effects
(Energy Policy Act of 1992).

Table 2.5 Summary of the PMI Components Considered by Western

PMI Components
Extension Period 10, 15, 25, or 35 years, or on a project-specific basis. The Preferred Alternative has an 18 to 20-year extension.
Percentage Extension 90%, 95%, 98%, or 100% of marketable resource; adjustment due to operational changes possible; adjustment only after an appropriate consultation process. The Preferred Alternative is project specific.
Resource Pool 10% (provides support of existing customer development of new C&RE technologies), 5%, or 2% for new customers/contingencies. No resource pool for some alternatives. The Preferred Alternative includes project specific resource pools that may be used for various purposes.
Resource Adjustment Provisions Tied to extension period; none for some alternatives; limited if contract extension is 15 years; one adjustment if extension is 25 years; two if extension is 35 years, project use adjustments are based on existing contract principles. One alternative would include adjustments on 5 years' notice for limited purposes.
Penalty All alternatives contain the penalty provisions prescribed in the Energy Policy Act. These provisions call for a 10% surcharge for nonsubmittal after 1 year from new rule adoption, or when customers fail to comply with approved plans; or after 9 months for failure to submit after the Administrator disapproves a plan; 20% surcharge after second year of noncompliance; 30% surcharge in third year of noncompliance. This time line is illustrated in Figure 2.1. The Act also allows for a 10% power reduction as an optional penalty.

All alternatives contain the penalty provisions prescribed in the Act. These provisions call for a 10 percent surcharge for IRP nonsubmittal after one year from new rule adoption, or when customers fail to comply with approved plans, or after nine months subsequent to Western's Administrator disapproving a plan when no satisfactory resubmittal occurs. A 20-percent surcharge is called for after the second year of nonsubmittal, the first year after failure to comply with a plan, or 21 months after a plan is disapproved when no satisfactory resubmittal occurs. A 30-percent surcharge is mandated in the third year of nonsubmittal and thereafter, the second year and thereafter after failure to comply with a plan, or 33 months after a plan is disapproved when no satisfactory resubmittal occurs. This time line is illustrated in Figure 2.1. The Act also allows for a 10-percent power allocation reduction as an optional penalty. In addition, Western proposes application of the penalty for nonsubmittal of an annual progress report in a timely manner.
A detailed description of the range of PMI components analyzed in this EIS is provided below. Assumptions used for modeling purposes are described in Chapter 3.

PMI Components Values or Ranges Used For The EIS Analysis

Extension Period

1) For PMI Extension Alternatives, 15, 25, or 35 years starting at expiration of existing contracts.

2) For PMI Limited Extension Alternatives, 10 years starting with IRP approval. After 10 years, new contract extensions would be determined by project-specific marketing plans.

3) For the PMI Non-Extension Alternatives, the extension would be determined by project-specific marketing plans.

Percentage Extension 90%, 95%, or 98% of marketable resource available at the end of the term of existing long-term contracts; 100% of existing commitments for certain alternatives.

The amount of power to be extended to an existing customer under the PMI Extension Alternatives would be determined according to the following formula:

Contract Rate of Delivery (CROD) extension =

(Customer CROD today / total project CROD under contract today) x percent extension x resource available at the end of the term of the existing contracts.

Where contract rates of delivery vary by season, the formula would be used on a seasonal basis. A similar pro rata approach would be used for energy extensions. Determination of the amount of resource available after the existing contract expires, if significantly different from existing resource commitments, would take place only after an appropriate public process.

Resource Pool

1) 10% of potential allocation reserved (coupled with 90% extension) for new customers, "contingencies," and support of existing customer development of new technologies for conservation or renewable resources.

2) 5% or 2% (coupled with 95% and 98% extension) for new customers and "contingencies."

3) One alternative couples a 98% extension with 2% for new customers only.

4) The PMI Limited Extension Alternatives include a 100% extension for the duration of the 10-year extension.

5) Any resource pool for the PMI Non-Extension Alternatives would be proposed on a project-specific basis.

6) Any resource pool for the Preferred Alternative would be established on a project specific basis. A resource pool of up to 6% would be established for the Pick-Sloan Missouri Basin Program - Eastern Division and Loveland Area Projects consisting of an initial extension followed by additional withdrawal opportunities 5 and 10 years into the contract term. The pool may be used for all purposes described in other alternatives.

New customer eligibility is limited by three factors: preference, utility status by a certain date, and being located in marketing area; one-time allocation for new customers is through a separate public process.

Resource Adjustment Provisions

1) Limited adjustment provisions (in conjunction with the 15-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.

2) One window to adjust marketable resources halfway through extension period (in conjunction with the 25-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.

3) Two windows to adjust marketable resources at 15 years and 25 years (in conjunction with the 35-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.

4) Two alternatives (Alternatives 8 and 13 in Table 2.6) allow for adjustments with 5 years' notice. The adjustment may only be used in response to changes in hydrology and river operations. Project use withdrawals can take place based on existing contract principles.

5) Contract extensions would be determined by provisions in project-specific marketing plans in the PMI Non-Extension Alternatives.

Penalty

The penalty provision (as mandated by Congress in the Act) would be triggered by nonsubmittal of an IRP in accordance with established deadlines; not reasonably addressing the seven IRP elements or other requirements; nonsubmittal of an annual progress report in a timely manner; or no good faith customer compliance with an approved IRP. Thereafter, a monthly surcharge of 10% of the purchase price on all power obtained by a customer from Western would be assessed for each of the next 12 months of noncompliance;

increasing to 20% for each of the following 12 months of noncompliance; and increasing to 30% thereafter until compliance takes place. Western reserves the right, in lieu of imposing a progressive surcharge, to impose instead a 10% resource withdrawal penalty if extraordinary circumstances exist. Penalty provisions would be incorporated into contracts that extend resources.

Table 2.6 Summary of Energy Planning and Mangement Program Alternatives Including the Preferred Alternative

Figure 2.1. Surcharge Penalty Provisions of the Energy Policy Act of 1992 a

2.1.2.1 PMI Extension Alternatives

For those alternatives featuring relatively longer term extensions of resources, Western proposes to apply the PMI for customers whose firm electric service contract(s) expire after December 31, 1995, and before January 1, 2005, if consistent with other contractual and legal rights. Western projects that would be proposed for initial coverage under these alternatives include the Pick-Sloan Missouri Basin Program-Eastern Division and Loveland Area Projects. Resource extensions under this group of alternatives would take place upon receipt of a customer's IRP by Western.

As for the Central Valley Project (CVP) resources, all power contracts between Western and its long-term firm customers expire in 2004, as does the Western-Pacific Gas & Electric Company integration contract. Because Western is presently preparing an EIS on Sacramento Area Office power marketing in the post-2004 time period, Western will not make any decision at this time about the application of the PMI to the CVP. (A notice of intent to prepare an EIS on the proposed Sacramento 2004 Power Marketing Program was published in the Federal Register on August 10, 1993 [58 FR 42536 as amended by 58 FR 43105, August 13, 1993]). Western will utilize the knowledge gained from this Energy Planning and Management Program EIS in the Sacramento 2004 power marketing EIS. The Program EIS will consider the environmental impacts of applying the Program Alternatives to the CVP. As a result of further analysis in the 2004 power marketing plan EIS, Western may at a later date propose adoption of the PMI for the CVP in the post-2004 time period.

If adopted, application of this PMI to the Salt Lake City Area/Integrated Projects (SLCA/IP) resources would be evaluated after the ongoing electric power marketing EIS for that project is completed and the associated marketing criteria and contracts are implemented. Western's preparation of that EIS formally started with the publication of a notice of intent to prepare an EIS in the Federal Register on April 4, 1990 (55 FR 12550). Western's Salt Lake City EIS is separate and distinct from the U.S. Bureau of Reclamation's EIS on the operations of Glen Canyon Dam; the notice of intent to prepare the Glen Canyon Dam draft EIS was published in the Federal Register on October 27, 1989 (54 FR 43870).

For this group of alternatives, Western also proposes to evaluate possible further application of the PMI at least 10 years before the termination of other Western firm electric service contracts that expire after January 1, 2005-principally the Parker-Davis and Boulder Canyon Projects. Determination of further application of this initiative would be published in the Federal Register after an informal consultation process.

For purposes of analysis, this EIS evaluates impacts associated with these PMI Extension Alternatives based on the assumption that the PMI would be applied to all of Western's projects.

Under the PMI Extension Alternatives, the current marketing criteria would remain in effect until the existing contracts expire. Western proposes to retain significant provisions of existing marketing criteria for those projects that will extend resource commitments beyond the current expiration date of long-term firm power sales contracts. Western wants to retain such important marketing plan provisions as classes of service, marketing area, and points of delivery to the extent that these provisions are consistent with the proposed PMI. The PMI, allocation criteria for potential new purchasers, and retained provisions of existing marketing criteria would constitute the future marketing plan for each project under these alternatives. Any necessary amendments to existing power marketing criteria could be pursued at the time that determination is made of the resource that will be available after existing contracts expire.

The PMI components under these alternatives include different possibilities for the contract extension term, percentage extension, existence of a resource pool and contract adjustment provisions. These features could replace key portions of Western's existing power marketing contracts that are described in Section 2.1, which discusses the No-Action Alternative. These features would not take effect until existing contracts expire.

Contract adjustment provisions for the PMI Extension Alternatives vary depending on the length of the resource extension. Limited adjustment provisions are proposed for the 15-year extension options; one window to adjust marketable resources is featured halfway through the 25-year extension period options; and two adjustment windows, at 15 and 25 years, are proposed for the 35-year extension options.

Adjustment provisions for Alternatives 8 and 13 would be different than for the other alternatives. The adjustment provisions are different in response to comments raised during the public participation process. Adjustments could be made on five years' notice only in response to changes in hydrology and river operations. Adjustment would take place only after an appropriate consultation process. Adjustments to contractual commitments could take place sooner if mutually agreed to by Western and the customer. Project use withdrawals could take place based on existing contract principles.

The adjustment provisions incorporated in Alternatives 8 and 13 would allow for timely response to changes in river operations and hydrology, while giving customers ample notice before any adjustment. The reasons for adjustment would be limited to only hydrology and/or operations to make Western's resource as firm as possible, while mitigating the need for possible purchase power requirements to meet firm load. Western believes this approach balances the need for reliable firm resources for customers with the recognized potential for future changes in available hydroelectric power resources.

A relationship would exist between the length of the contractual extension and the percentage of the extension in this set of PMI Alternatives. The longer the term of the resource extension, the greater the risk in committing to a high level of resource availability. Western believes that a resource extension should provide the resource stability needed for effective IRP. A short extension period might be insufficient to maintain an adequate customer planning horizon and to allow for long-term project financing. For example, the short-term allocation of power to entities on the basis of energy-efficiency accomplishments would undermine resource certainty, which is the foundation of quality IRP. An extension beyond 35 years is simply too far into the future to commit resources, as Western's flexibility to respond to changing circumstances would be compromised.

Western believes that an extension of less than 90 percent of the resource to existing customers may lead to unnecessary power supply dislocations and potential development of new, but largely unneeded, supply-side resources, lessening the efficiency of the integrated system and defeating the purpose of IRP.

2.1.2.2 PMI Limited Extension Alternatives

This set of two PMI alternatives would extend commitments of Federal resources to existing customers for a period of time sufficient to allow 1) the development of project-specific marketing plans by Western, 2) customer planning for resources in the event the project-specific hydropower resource is adjusted, and 3) the acquisition of any resources chosen during the customer planning process. Contracts for resource extensions would be signed upon approval of a customer's initial IRP by Western.

The objective of this group of alternatives would be to provide Western's customers with the minimum extension necessary to support customer preparation and implementation of IRPs. Under the Energy Policy Act of 1992, customer IRPs are due to Western one year after the final regulations become effective. Two- and five-year action plans are required in each IRP. Western believes that customers must have sufficient certainty regarding hydropower availability to plan intelligently on a least-cost basis for the future. If existing long-term firm hydropower commitments expire within the customer's planning horizon, quality least-cost planning for the future cannot take place with any confidence. The limited extension group of alternatives would respond to this situation by extending 100 percent of existing resources to existing customers for 10 years from the date of IRP approval by Western. This approach would provide for an allocation until project-specific marketing criteria can be developed and customers can adjust to the results. These alternatives are different from the others in that the extension of resources would be contingent on submittal and approval of an acceptable IRP.

The intent associated with this set of alternatives is to extend resources for a period of time adequate to effectuate a customer's IRP. For purposes of modeling and analysis, a 10-year period was tentatively chosen as an appropriate length for several reasons. If no long-term firm extensions are made pursuant to the Program, Western must develop project-specific marketing and allocation criteria for the time period after the limited extension expires. Assuming that environmental impact statements are required, Western estimates that it would take three to four years to complete each marketing plan, depending on the level of controversy. If less than 100 percent of the resource were allocated to existing customers, other resources would have to be identified by the customer to replace the unextended resource. This planning process could take as long as one year to complete. Resources identified in an IRP could be supply-side (either construction or purchase), demand-side, or renewable in nature. Implementation of demand-side measures could take as long as three years, while construction of supply-side resources could take from three to 10 years, depending on the character of the resource. Ten years appears to be a time period within which all of these activities could be accomplished, and is consistent with the shortest long-term planning horizon used in the electric utility industry.

These PMI alternatives would apply only to projects where existing long-term firm contracts expire within 10 years of the date of initial IRP approval by Western. Customers with contracts for long-term firm power from the Pick-Sloan Missouri Basin Program-Eastern Division would likely receive resource extensions for five to six years under the PMI Extension Alternatives, depending on the date of IRP approval. Customers with contracts for power from the Loveland Area Projects would probably only receive extensions for one or two years, while entities purchasing power from the Central Valley Project or the Salt Lake City Area Integrated Projects could also receive modest extensions. This alternative would not be applicable to resources under contract far into the future, such as the Parker-Davis and Boulder Canyon Projects; a limited extension in support of IRP reffectuation is unnecessary when existing contracts extend far into the future.

2.1.2.3 PMI Non-Extension Alternatives

Under this set of alternatives, Western would implement the provisions of the Energy Policy Act of 1992 without extending resources under this Program. These alternatives combine the requirements of the Energy Policy Act of 1992 (including the new penalty provision) with the PMI provision of the No-Action Alternative. All power would be marketed on a project-specific basis, with independent public processes and environmental documentation.

2.1.3 Conservation and Renewable Energy Program - An Element of the No-Action Alternative

In 1981, Western developed and began implementing a power marketing contract article requiring purchasers of long-term firm power (Western's customers) to develop a C&RE program. The C&RE program forms the No-Action Alternative. G&AC specify the requirements for customer C&RE plans. The G&AC were published in the Federal Register (46 FR 56140) on November 13, 1981. Legislation reinforcing Western's ongoing program was included in Title II of the Hoover Power Plant Act (42 USC 7275-7276). After the Hoover Power Plant Act was passed, an amendment to the G&AC was published in the Federal Register (50 FR 33892 1985). G&AC requirements are incorporated into a C&RE contract article, which is part of a customer's existing power marketing contract. The contract articles contain a noncompliance penalty provision of a 10-percent reduction in Western power contract commitments.

Western notified the public in January 1993 that it would no longer require customer compliance with the G&AC in order to facilitate the preparation of IRPs by Western's long-term firm power customers (58 FR 3552). To have a basis for comparative analysis, the No-Action Alternative assumes the G&AC would have continued in the absence of Program adoption and passage of the Energy Policy Act of 1992.

Under the G&AC, customers were responsible for developing and implementing programs for efficient energy production and conservation goals. A customer's program submission described specific program content. Western's G&AC included a list of suggested actions for customer consideration. This list is reproduced in Appendix B. The list is broad and includes activities in the areas of energy consumption efficiency improvements, use of renewable energy resources, load management techniques, cogeneration, rate design improvements, production efficiency improvements, and activities conducted for other agencies. Western gave full or partial credit for programs required by other entities that met the requirements of the C&RE program.

Acceptance criteria for customer programs were based on the customer's classification (i.e., cooperative, public utility district, etc.) and the level of effort proposed.

Customer programs were required to contain a minimum number of annual on-going or planned activities. The number of activities varied by utility type and the quantity of system sales or consumption. The smallest customers were required to do one C&RE activity; the largest customers five. Table 2.7 shows the required number of activities for each customer type.

The descriptions of these activities, including goals and schedules, were the most important elements of a C&RE plan. The customer's program submittal included the following items as part of this description:

* a description of each ongoing or proposed Program activity; customers are to use the G&AC list for activity selection (this list is contained in Appendix B). Where energy savings or added energy/capacity supply goals may be quantified for each activity, such data should accompany each program submittal
* identification of customer goals, plans, schedules, and locations for each activity
* methods for determining successful program accomplishment
* documents prepared for other Federal, State, or local agencies that could be submitted in lieu of or supplemental to Western's requested information
* specific areas where a customer feels that assistance is needed from Western
* identification of potential adverse environmental impacts and issues of proposed C&RE activities
* any additional data or information that a customer wants to include as part of a program description.

Western reviewed customer programs every two years. Every four years verification of at least 70 percent attainment of goals was required. Western's C&RE review process consisted of the following elements:

* reviewing customer submissions against defined criteria
* answering customer questions and providing necessary assistance
* imposing penalties if a customer is found in violation of its contractual C&RE obligation.

Western committed to review and may modify the G&AC criteria at intervals of not less than three years or more than five years (50 FR 33892 - 33899, August 21, 1985). It was as a result of one of these reviews that Western initially proposed the program modification assessed in this EIS.

Western recognizes that the past efforts of many of its customers in implementing conservation and DSM have been significant and have far exceeded the minimum requirements under the C&RE program. Historic investments by Western's customers will influence the future resources available for consideration in an IRP.

Although enforcement provisions for noncompliance with the G&AC are included in all long-term, firm contracts, the existing C&RE program is not directly linked to power marketing provisions such as contract extensions and percentage allocations.

Table 2.7. Required C&RE Ongoing Activities for Customer Programs

Customer Type	Total customer system sales or annual consumption if a nonutility (in GWh/yr)		
	<50	50 - 100	>100
Cooperatives	3	4	5
Municipalities	3	4	5
Public utility districts	3	4	5
Federal or State agencies	3	4	5
Investor-owned utilities	3	4	5
Parent entity and members	3	4	5
Public power district	3	4	5
Irrigation district with utility function	3	4	5
Irrigation district without utility function	1	1	1

Source: 50 FR 33897

2.1.4 Technical Assistance - An Element Common to All Alternatives

Western's technical assistance program has been successful in helping utilities meet program requirements and accomplish their goals in conservation and renewable energy. Western fully intends to continue providing its customers with an appropriate level and mix of technical assistance.

Technical assistance is a program element that spans across all alternatives. Western is committed to the pursuit of technical assistance activities, and recognizes that the level of effort and the types of activities would be similar under the various alternatives. The content of specific workshops or seminars that Western may offer might vary under the alternatives because of differing program requirements and customer needs. However, these variations are likely to be minimal and would not affect the level of overall effort.

Since 1981, Western has provided its customers with a wide range of technical assistance in support of the conservation and renewable energy program. The approximate budget for this support in fiscal year 1995 is $5.0 million. Additional funding from sources providing complementary service and partnerships with customers continues to be sought to leverage the benefits of the service, reduce financial risk, and remove barriers to the successful application of emerging technologies.

Western evaluates its involvement and support for technical assistance and technology transfer activities against the following criteria, which are consistent with those for a successful energy management program: the activity must maintain or enhance the existing level of energy service; the activity must produce benefits that equal or exceed the cost to the customer and/or consumer; the benefits must be measurable; and the activity must be environmentally sensitive.

IRP is the focus of Western's support activities. An example of this IRP focus is Western's development of a series of workbooks known as the Resource Planning Guide (RPG). The RPG, which has been under development for a number of years, provides Western's customers with a guide to the development of an IRP process. The RPG has been well received as a valuable planning tool for the future. The RPG, which was developed with the participation of more than 40 utilities, is now available in a computer disc format for customer use in compliance with the final Program regulations. Activities such as workshops, peer matches, seminars, equipment loans, technology transfer, publications, and cooperative cost-shared efforts with customers and other supporting organizations would continue, especially as they relate to IRP. In addition to those ongoing assistance efforts, Western is willing, in cooperation with its customers, to develop joint venture DSM and renewable energy pilot/ demonstration projects. Some possible additional activities include assistance in developing new funding and incentive programs to promote DSM, and locally based technical services to specific customer groups. One specific example of this is a photovoltaics "circuit-rider," a technician who provides support services to a group of customers who participate in the funding.

Western's technical assistance support is available to customers upon request. The technical assistance Western offers is best described as a set of tools which customers use in support of meeting their contractual obligations. Not all customers need or want such assistance. On the other hand, technical assistance will help many customers to meet or exceed program requirements.

Western's technical assistance has been tailored each year to meet the current needs of the program and the customers. Given the numerous changes and challenges experienced and anticipated in the utility industry, and rapidly changing technologies, it is not possible to project exactly what the content of technical assistance efforts may be over the projected term of proposed contract extensions. Technical support must remain flexible and capable of rapid change. Western has provided for such change in the last decade and will continue this practice in the future.

External factors may have the most influence on the types of assistance that will be needed. For example, Western may need to train its customers in the future in the application of new technologies that have not yet been developed, or new approaches that are yet to be designed. As specific technical assistance activities are proposed in the future, they will be evaluated for appropriate documentation under NEPA.

2.2 ISSUES NOT INCORPORATED INTO ALTERNATIVES

The range of alternatives incorporated into this EIS was determined after an extensive public involvement process which included 53 public meetings and workshops, and distribution of eleven newsletters and one brochure to explain the issues and allow for public involvement. Ranges of alternatives were set forth in a public newsletter distributed in September of 1991; these initial ranges were explained and discussed in a public meeting held on September 30, 1991, in Denver, Colorado. In addition, eight alternatives workshops were held in March and April of 1992 to help further define alternatives. Eight public hearings were held in April and May of 1994 to receive comment on the draft EIS.

A number of issues raised during the Program development process have been found to be not responsive to the need for the Program or its purpose, and were determined to be outside the scope of Western's analysis. Therefore, these issues were not incorporated into alternatives evaluated in this EIS. The following subsections provide clarification and information about these issues.

2.2.1 Transmission Access

Western encourages and practices open transmission access. However, Western believes that giving credit to a customer providing access to its transmission system is not within Western's specific need of encouraging customers to pursue improvements in their energy management efforts. The important and controversial issue of transmission access will be addressed and resolved through other processes. Even though the issue of transmission access will not be addressed through the decision-making process addressed by this EIS, Western believes that access to reasonably priced transmission is an important consideration in a customer's resource comparisons and evaluations in an IRP. This is especially the case when a particular customer needs transmission access to acquire a cost-effective resource.

2.2.2 Incentive Rates/Rate Design Modifications by Western

Incentive rates and rate design modifications are not analyzed as part of this EIS. While alternatives to Western's rates and rate designs might encourage conservation, they would not encourage comprehensive long-term energy management planning by Western's customers. Western believes that incentive rates and rate designs to encourage conservation should be appropriately analyzed in subsequent environmental documentation associated with proposed changes to the existing rate and rate design methodologies, within the long-established, public rate-making process. Procedures to ensure appropriate public participation in the rate development process are set forth in 10 CFR 903.

2.2.3 River and Dam Operations

The PMI portion of the Program includes components for the amount of resource extended to current customers, the length of the extensions, and the amount of resource designated for a resource pool that may be used for several purposes. The Program does not propose to alter the total amounts of power or energy marketed by Western, or to make changes in the conditions for marketing of power and energy, or to make changes in the operations of any generation facilities. In fact, the Program is intentionally designed to respond to changes in marketable resources due to hydrology or operational changes, which very likely would be initiated by agencies other than Western.

Any proposed future changes to marketing conditions, or to river or dam operations, or any other action that may cause such changes would be a separate Federal proposed action with its own purposes and needs. Such actions may refer to this EIS and would have separate NEPA environmental documentation to analyze the impacts from defined actions to specific river systems.

The Program will neither cause changes to river or dam operations nor will it impede such changes. All alternatives are neutral with respect to river and dam operations, even though some may offer Western more flexibility in responding to operational changes stemming from other actions or projects.

2.2.4 Ecological and Recreational Resources

In a manner similar to the preceding river and dam operations issue, the proposed Program does not change the conditions under which Western markets power and energy, or the operation of rivers or dams. Any future changes to power marketing conditions or changes to river or dam operations that may have impacts on ecological or recreational resources are separate proposed actions with their own purposes and needs. Such actions, which may be proposed by other Federal agencies, will have their own NEPA environmental documentation.

The Program will neither result in changes to ecological or recreational resources caused by changes in river and dam operations, nor will it impede such changes. All alternatives are neutral with respect to these ecological and recreational resources, even though some may offer Western more flexibility in responding to future changes. Customer responses to Western's proposed Program may result in ecological impacts, which are described in Chapter 4 and summarized in Section 2.5.

2.2.5 Regional IRPs

During the scoping process, comment was received that Western should develop regional integrated resource plans (IRPs) for each of the geographic regions it serves, either by river basins or some other demographic boundaries. Such IRPs would, almost by definition, be extensive in scope and require the expenditure of substantial resources. Some opinions favor the inclusion of such IRPs in this Program.

Western has no load growth responsibilities - the power customers do. Western markets a fixed supply of hydroelectric power that is subject to seasonal weather fluctuations in various geographical regions. The vast majority of Western's customers are not solely dependent upon Western for their supply of power. Western does not have legislative or regulatory authority over the supply or demand of the customers its serves. Under these circumstances, it is neither appropriate nor feasible for Western to attempt to develop regional IRPs for its 15-state service territory.

Western believes that resource, geographic, and other differences among areas of its service territory will be evident as a result of any IRP process conducted by its customers, and therefore, it is unnecessary to attempt to modify the "process" itself to the needs of different regions. Regional sensitivities are reflected in this EIS and will be highlighted in customer IRPs.

2.2.6 Conservation Purchases by Western

The option for Western to purchase energy conservation in lieu of furnishing a supply of power from its hydroelectric resources was suggested during the scoping process.

Western has committed to the use of principles of IRP in its resource acquisition and transmission planning activities. This commitment is being pursued through a separate public process. Acquisition of demand-side and efficiency resources will be considered by Western in the future, but is outside the scope of this EIS.

2.2.7 Project Use Efficiency

Western received comments that it should invest in energy use efficiencies for project use loads. Project use power is that power reserved to meet project needs as authorized by Congress, such as main lift pumping for irrigation, station service, and salinity control. Western markets power available in excess of that needed to serve project purposes.

Western received comments that it should allocate the project use energy saved to preference customers or reduce firming purchase power requirements. Western also received a comment that customers could be given the opportunity to make efficiency improvements in exchange for the energy saved.

Investment opportunities have been discussed with the U.S. Bureau of Reclamation and the U.S. Army Corps of Engineers which are responsible for project use facilities. An evaluation report, done by Western and the Bureau of Reclamation on project use efficiency opportunities for the CVP, indicated very limited cost-effective opportunities for development (U.S. Bureau of Reclamation et al. 1992). However, the four potential generation efficiency improvements that were cost-effective could increase project energy available for marketing by 123 GWh per year at a cost of 0.7 to 36.9 mills/kWh.

Because Western's investment in project use efficiency improvement opportunities does not encourage long-term energy management planning by Western's customers, Western will not include this issue within the Program EIS analysis. These opportunities have been and will be pursued independently.

2.2.8 Proposed Percentage Allocations, Resource Pools, and Contract Extensions

Reviewers of the draft EIS suggested two combinations of percentage allocations, resource pools, and contract extensions. One set included a 10-year contract term with a 70 percent allocation. Another suggested a 35-to-40-year term with a 98 percent to 100 percent allocation.

Western has determined that the 70-percent/10-year Alternative would not be reasonable for analysis in the final EIS. The 10-year contract term is already included in existing Alternatives. The 70-percent allocation, with the remainder going into a resource pool, allows too much power to go unallocated because potential new customer loads do not require such a large allocation. Leaving the power unallocated would lead to unnecessary power supply dislocations and potential development of new, but largely unneeded, supply side resources, defeating the purpose of IRP. This proposal would not meet the underlying purpose and needs for the program.

Elements of the 100-percent/35-year proposal are already present, although not in this combination, in the alternatives modeled in the draft and final EIS. The Preferred Alternative is treated as a combination of Alternatives 5 and 6 and was not modeled separately. The proposal does extend Western's percentage of resource extension to 100 percent. Making this adjustment adds little to describe or change the environmental impacts already captured by the existing Alternatives. Further, a 100-percent allocation would leave no power available to meet a fair share of the needs of new customers.

Western has determined that neither of these proposals form reasonable Alternatives for inclusion in this EIS. However, to aid the evaluation of the Alternatives that are presented, additional information on potential impacts resulting from these proposals is presented in the Response to Comments, located in Appendix G.

2.3 INCENTIVES

Western received public comments that incentives should receive more emphasis in the Program. Allocations of power from a resource pool to customers with exemplary achievement in energy efficiency were suggested as incentives. Western believes that the adoption of such competitive incentives for program compliance is impractical for the following reasons.

Western serves a wide variety of customers. Western has recognized from the outset that there would be varying levels in the sophistication and complexity of IRPs, reflecting each customer's size, type, resource needs, and geographic area. Resource choices and the timing of implementation would vary depending upon the circumstances involved. Given this diversity of customer characteristics and resource strategies, Western has not found an equitable way to judge and appropriately reward the energy efficiency achievements of its customers. For example, it would be a difficult task to decide whether the conservation efforts of a small irrigation district are comparable to the achievements of a much larger, vertically integrated utility. Since larger utilities have more opportunities to excel in this area, competition for power could serve to redistribute power from smaller customers to larger utilities with the staff, resources, and knowledge to succeed. Because customers facing load growth have greater opportunity to plan and implement cost-effective DSM and energy efficiency resources, the concept of competition could similarly work to the detriment of customers facing stable loads or experiencing supply-side resource surpluses.

Western has another concern about providing incentive allocations out of a resource pool. When an incentive allocation is made up of long-term firm power taken from existing customers, Western undermines resource stability to existing customers. Due to customer uncertainty of receipt of power from such a pool, otherwise unnecessary power purchases or long-term commitments for purchases could take place, causing increased expense to the consumer. In regions where surpluses are not available for purchase on a long-term basis, construction of supply-side generation or transmission lines could be induced if Western creates a relatively large resource pool from power currently allocated to existing customers. Balance must be achieved between avoiding disruption in existing power supply and transmission arrangements and the development of appropriate incentives for IRP preparation. For these reasons, the alternatives do not feature the allocation of long-term firm power out of a resource pool as an incentive for existing customers.

Some extension alternatives evaluated in this EIS propose that resource extension contracts be signed upon receipt of a customer's IRP by Western. Other alternatives would have extension contracts executed upon approval of a customer's IRP by Western. Both of these approaches feature incentives for the expeditious preparation and submittal of quality IRPs.

The planning stability that results when a customer can depend on its Federal power commitment can be seen as an incentive. Planning for the future cannot take place with any confidence if this stability is compromised. Energy-efficient resource choices, with their associated economic and environmental benefits, are more difficult to realize if the existing resource base is uncertain. The financing of new renewable and DSM resources could be adversely impacted if existing resources are not sufficiently firm for planning purposes.

Customer energy efficiency is driven by the cost of supplemental electricity supply. The price differential between Western's power and the cost of power from other sources is often significant. Western believes that the economic price signals resulting from this price disparity offer a more significant incentive than any Western could propose. Western provides a varying amount of a customer's energy needs but virtually all customers require a supplemental supply to meet their total energy needs.

Western also views its technical assistance program as offering a significant incentive for customers to pursue energy efficiency. A major goal of Western's technical assistance program is to inform its customers of the economic benefits of energy efficiency, so that opportunities identified in IRPs are pursued with an understanding of those benefits. Assistance is available from Western to aid customers in their development of consumer incentives for energy efficiency. Better energy efficiency achievement results when effort is focused on utility incentives to consumers, as opposed to incentives from Western to a purchasing utility. This is especially the case when the purchasing utility is a MBA one or two levels removed from the end-use consumer.

Technical assistance would also support the marketing efforts of Western customers as they pursue cost-effective demand-side management activities. The environmental and cost-saving benefits resulting from IRP preparation, developed with full public participation, are sufficient incentives for IRP implementation without further incentive from Western.

Western originally viewed the extension of resource commitments to existing customers as a significant inducement for the preparation of IRPs. With the passage of the Act, Western's long-term firm power customers now must prepare IRPs whether resources are extended or not. However, the availability of power for allocation to new customers remains a powerful incentive for the preparation of IRPs by those not presently receiving the benefits of Federal hydroelectric power.

Western continues to investigate the possibility that further regional energy efficiency incentives might be identified. Western may, if appropriate, develop targeted incentives on a project-by-project basis, if such an approach has regional merit. One opportunity for consideration of such an incentive approach would be at the time that Western determines the resource available at the end of the term of existing contracts. Further NEPA environmental documentation would be prepared, as needed, when Western considers specific future actions.

2.4 GROUPINGS OF ALTERNATIVES

The IRP and PMI components, along with the features of the amended G&AC, make up the components for the 13 alternatives analyzed in this EIS. The Preferred Alternative is treated as a combination of Alternative 5 and 6 and was not modeled separately. The alternatives are summarized in Table 2.6. In its June 1992 UPDATE newsletter, Western identified a tentative preferred alternative as the alternative it was most likely to endorse, subject to the results of the ongoing analysis. To ensure that the Program Alternatives featured in this EIS were given fair and equitable consideration, Western did not select a preferred alternative until after public comments on the draft EIS were considered.

2.4.1 The No-Action Alternative

The No-Action Alternative consists of the amended C&RE program and the project-specific independent marketing plans established by the area offices. Currently, Western markets its resources through independent marketing plans that are developed for specific hydroelectric projects, each with its own set of customer power contracts.

Under the No-Action Alternative, the existing time frames for Western's resource marketing would remain the same. Four of the existing plans will expire by 2005. In the Billings Area Office contracts for 2,029 MW (including peaking power) will expire in 2000. The Sacramento, Loveland, and Salt Lake City area offices administer contracts for a total of 3,341 MW set to expire in 2004. The Phoenix Area Office markets 217 MW from the Parker-Davis Project under contracts that will expire in 2008. Western anticipates extended contracts under this alternative would incorporate variable contract terms. The contracts would not include provisions for adjustments or resource pools.

2.4.2 The PMI Extension Alternatives - 2 through 8

Alternatives 2 through 8 provide different approaches to linking power marketing with energy management. Western has developed four packages of options for the PMI portion of the Program and two options for the IRP provision. In combination, these packages make up seven alternatives under discussion. The IRP package contains the following combination of components.

Each of the alternatives includes IRP; some offer small customers the choice of other ways of meeting the EMP requirements.

* IRP Option A - IRP required for all customers.
* IRP Option B - IRP required for most customers, but Western would establish different regulations for certain small customers with total energy sales or usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility. These customers shall consider all reasonable opportunities to meet future energy services requirements using DSM techniques, new renewable resources and other programs that will provide retail customers with electriciaty at the lowest possible cost, and minimize, to the extent practible, adverse environmental effects.

All PMI extension options include an identical penalty provision as required by Section 114 of the Energy Policy Act of 1992. This penalty provision would be incorporated into th contracts that extend resources.

The resource pool provisions under Alternatives 2 though 8 allow for allocations to new customers and for contingencies. The PMI extension options are summarized below:

* PMI Option A - 15-year contract term with a 98 percent extension of resources, a 2-percent resource pool, and limited adjustment provisions.
* PMI Option B - 25-year contract term with a 95 percent extension of resources, a 5-percent resource pool, and one window to adjust resources halfway through the term.
* PMI Option C - 35-year contract term with a 90 percent extension of resources, a 10-percent resource pool, and two windows to adjsut resources at 15 years and 25 years. The resource pool under this option includes a provision to support existing customer development of new technologies for onservation or renewable resources.
* PMI Option D - 25-year contract term with a 98 percent extension of resources, a 2-percent resource pool and limited adjustment provisions on five years' notice.

2.4.3 The PMI Limited Extension Alternatives - 9 and 10

This pair of Limited Extension Alternatives would extend commitments of Federal resources to existing customers for a period of time sufficient to allow 1)the development of project-specific marketing plans by Western, 2) customer planning for resour

es in the e
ent the project-specific hydropower resoruce is adjsuted, and 3) the construction of any resources chosen during the customer planning process. The time period for extension would start from the date of Western's approval of a customer's IFP; the extens

on amount w
uld be 100 percent of existing resources. Provisions of the Energy Policy Act of 1992 would be implemented.

2.4.4 The PMI Non-Extension Alternatives - 11 and 12

Under this pair of Non-Extension Alternatives, Western would implement the provisions of the Energy Policy Act of 1992 without extending resources under this Program. Alternative 11 would require preapration of IFPs, while Alternative 12 would allow

for small c
stomer provisions. These alternatives couple together the requirements of the Energy Policy Act of 1992 (including the new penalty provision) with the PMI provision of the No-Action Alternative.

2.4.5 The Preferred Alternative

Western has chosen a Preferred Alternative. This Alternative formed the basis of the agency's Proposed Energy Planning and Mangement Program, as described in its "Notice of Proposed Program and jRequest for Public Comments," published in the Federal

Register on
August 9, 1994 (59 FR 40543). The Preferred Alternative is made up of th ecomponents described in Table 2.8. The environmental effects of the Preferred Alternative are similar to those of Alternatives 5 and 6 and fall somewhere between them. Because o

its simila
ity to Alterntive 5 and 6, the ability to distinguish the impacts of the Preferred Alternative by interpolating between these existing Alternatives, and the similarity of the impacts calculated for Alternatives 5 and 6, additional analysis was not perfor

ed for the
referred Alternative.

2.5 SUMMARY OF ENVIRONMENTAL IMPACTS

Table 2.6 summarizes the salient provisions of the 13 alternatives. The Preferred Alternative
is treated as a combinatino of Alternative 5 and 6 and was not modeled separately. All Program Alternatives would have beneficial environmental and social impacts incomparisione to the No-Action
Alternative. The impacts of the Program Alternatives vary depending on the environmental resources being affected. There are two key issues that contribute to the variation. The first is the operation of generating technologies that would result under each alternative. Effects that are
primarily related to coal combustion (for example SOx and TSP emissions or ash production) would tend to remain unchanged across the Program Alternatives. Effecs taht result form both natural gas and coal (for example, thermal discharge, water consumpti

n, and CO2
missions) would tend to vary more by
alternvative as natural gas is used to a differing extent in response to uncertainty resulting from
Western contract allocations. When comparing the impacts from total regional generation, these differences are quite small, less than 1 percent. However, when comparing the incremental changes between the alternatives, the difference varies from 2 percent to 23 percent.

The second issue is the distinction between impacts resulting from generation and those resulting
from the construction of new capacity. Impacts related to new capacity would include land use and construction employment. The differences among each alternative's effects on these categories tend to be
magnified in comparison to the effects resulting from generation due to the focus on only new development, without the influence of existing generation plants. Existing plants, which tend to dominate the
effects of new plants, have much greater influence on the effects resulting from electricity

generation. Potential impacts are summarized in Tables 2.9 and 2.10.

Two analytic techniques were used to assess employment impacts and effects on trade and commerce. Taken together, these analyses show impacts ranging from neutral to positive resulting from the Program Alternatives in comparison with the No-Action Alternative. The Program Alternatives would tend to increase estimated direct employment from the construction of generation plants and the installation of conservation measures. These jobs would result from the labor-intensive nature of conservation. The Program Alternatives are projected

to increase direct employment from approximately 12,400 to 12,700 employee years in 2005 and from approximately 31,000 to 32,000 employee years in 2015 (see Tables 2.9 and 2.10). Taken together over the 20-year study period, the increment between the alternatives amounts to an average of about 2,200 employee-years per year. On a regional basis the Program Alternatives would affect the regional economy neutrally. The economic impacts on trade and commerce were found to be nearly zero with some slightly negative effects through 2005 and 2015 across all five of the Western areas (see Section 4.9, "Social and Economic Effects"). `

Rate impacts were analyzed from a number of perspectives. The Program Alternatives could result in short-term rate increases to cover the cost of IRP. However, the Program Alternatives should result in a rate decrease over time as utilities make mo

e efficient use of resources (see Section 4.10 "Rate Impacts").

The Program itself would ahve no direct impacts on the environment. Western estimates the Program's aggregate indirect impacts that would be produced by the anticipated customer response, but specific customer activities in response to the Program cannot be determined. These specific activities could have impacts in the future, and would be addressed once specific actions are identified. In comparison with the No-Action Alternative, the analysis found taht the Program Alternatives would consistently result in fewer negative physical environmental effects.

Table 2.8. Preferred Alternative Components

	ENERGY MANAGEMENT PROGRAM
IRP	Required of most customers
Small Customer Provision	Yes
	POWER MARKETING INITIATIVE
Extension Period	18-20 years
Percentage Extension	Project-specific extensions of no less than 94% for the Pick-Sloan Missouri Basin Program-Eastern Division and Loveland Area Projects; percentage to be determined for other projects. Extension contracts would be offered upon publication of the Record of Decision in the Federal Register, subject to subsequent approval of the submitted IRP/small customer plan.
Resource Pool	Total resource pool of up to 6% for the Pick-Sloan Missouri Basin Program-Eastern Division and Loveland Area Projects, which includes both an initial pool followed by additional withdrawal opportunities 5 and 10 years into the contract term; other projects to be determined. The pool may be used for all purposes described in other alternatives, including allocations to new customers, customer development of new technologies for conservation or renewable resources, and contingencies.
Resource Adjstment Provisions	On 5 years' notice for changes in operations and hydrology; project use withdrawals in accordance with existing marketing plans and contracts.
Penalty	All alternatives carry the penalty provisions prescribed in the Energy Policy Act.

CHAPTER 3 Affected Environment

This chapter describes the environment to be affected through the year 2015. Western assumes that under the No-Action Alternative most components of the environment would continue to be impacted by energy resource development and operation. The difference between future conditions and any associated trends under the No-Action Alternative and those under the Program Alternatives would be apparent in only certain parts of the environment, such as air and water quality. The future conditions that would be most affected by the Program are conservation, the operation of existing power plants, and the construction and operation of new capacity. This chapter focuses on components of the environment that would be affected by these differences.

Western is proposing a customer planning process, but not specifying the results of that process. Western's customers would make choices appropriate to their individual situations that would determine the specific locations of the impacts that Western can describe only in a general sense in this EIS. As specific actions are established, detailed environmental analyses would be developed by those initiating the projects as required by State and Federal legislation.

Summaries of general information about environmental resources, such as landforms, river and drainage basins, vegetation, climate, and threatened and endangered species are provided in Section 3.1. Section 3.2 discusses ambient air quality and indoor air quality. Section 3.3 discusses water quality. Land use and solid waste are discussed in Section 3.4. Sections 3.5, 3.6, and 3.7 describe the socioeconomic conditions, existing utility planning activities, and Western's relationship with its customers, respectively. These environmental resources are important factors in the environmental analysis described in Chapter 4.

3.1 PHYSICAL DESCRIPTION

Western's service region is broad and diverse. It covers 1.3 million square miles and 15 states. This section provides summary information about the natural landforms, climates, and plant and animal species found in the Western service region. This region comprises a diverse and rich environment that is briefly described here. The region's physical geography would not be directly impacted by the alternatives discussed in this EIS. As Western's customers respond to the requirements of the Program, utilities may take actions that would impact the physical environment. The analysis in the environmental consequences chapter (Chapter 4) assesses the expected aggregate magnitude of these potential effects, but the context of these impacts is not now predictable.

The watersheds of Western's service region drain many of the great landforms of the western United States and feed many of the great rivers of the continent. These rivers are of crucial importance to Western. The hydroelectric projects built on these rivers provide the vast majority of Federal electricity that the agency markets. Figures 3.1 and 3.2 show the major rivers and basins in the region. Figure 3.3 shows the major landforms of the region. A discussion of water quality in Western's service region is contained in Section 3.3.

The climate is an important element in the availability of electricity generated from hydroelectric power. The climate is also a key driver in how pollutants generated at a central location are dispersed. Climate is also important in determining electricity consumption and the kinds of conservation measures that will be effective in reducing consumption at important times.

Figures 3.4 and 3.5 illustrate heating and cooling degree days over the entire United States. These units are important to utility planners designing conservation programs and building codes, as well as those forecasting future utility loads. Heating and cooling degree days are based on temperature differences and the amount of time that heating or cooling is needed in different regions. A heating degree day amounts to 24 hours of outdoor temperature 1 Fahrenheit (F) below 65F. (Therefore, 1 full day with an outdoor temperature of 60F would equal 5 heating degree days.) A cooling degree day is a similar measure of the need for cooling. One cooling degree day amounts to 24 hours of ambient temperature 1F over 65F.

Figure 3.1. Major Rivers and Watersheds of Western's Service Area (Adapted from Geraghty et al. 1973; State of California 1979)

Figure 3.2. Major Basins of Western's Service Area (Adapted from Sigler and Sigler 1987; Geraghty et al. 1973; Becker and Neitzel 1992)

Figure 3.3. Major Landform Divisions of Western's Region (Adapted from Hammond 1964; National Geographic Society 1976)

Figure 3.4. Mean Annual Heating Degree Days (SERI 1991)

Figure 3.5. Mean Annual Cooling Degree Days (SERI 1991)

Figure 3.6 shows long-term statistical information about precipitation in cities scattered around Western's service region. Record high and mean levels of precipitation are shown. An understanding of precipitation and hydrology is important in forecasting the stability of hydroelectric resources. In addition, where precipitation is scarce, more importance will be placed on water consumption for energy production.

Figure 3.6 Mean Monthly Precipitation (DOI 1970)

Information about available sun energy and wind energy is discussed in Appendix E. These climatic elements are important as sources of renewable energy and because the formation of reactive air pollutants and the dispersion of all air pollutants is tied to the intensity and duration of sunlight and wind.

Figure 3.7 characterizes the general vegetation types found in Western's service region. Air emissions from existing and new power plants may impair vegetation as discussed in Appendix A. Other direct effects to vegetation are expected to occur due to the development of energy facilities such as new plants, transmission lines or substations, although the specific locations cannot be predicted.

Figure 3.7 Vegetation Types Found in Western's Service Region (Adapted from Mason and Mattson 1990; Shelford 1963)

Figure 3.8 Number of Threatened, Endangered, and Sensitive Species of Mammals, Birds, Fish, and Plants in Each State of Western's Service Region (Adapted from Di Silvestro 1985)

Threatened and endangered species are an important consideration in choosing locations for energy facilities and for changes in their operation. Very detailed information is needed to calculate impacts to particular species from each project. Species may be impaired by habitat disruption or exposure to pollutants. Figure 3.8 shows the number of endangered species found in each of the states contained in Western's service region. The figure illustrates the extent of the issue and suggests the complexity of assessing impacts to specific species. Under the No-Action Alternative, threatened and endangered species impacts could continue to occur through the development and operation of energy resources.

3.2 AIR QUALITY

Under the No-Action Alternative, ambient air quality will be dynamic and dependant on location. In some areas, air quality may improve as a result of air quality regulations and emissions restrictions. In other regions air quality may degrade or remain unchanged. Western's region is predicted to need new generation facilities, which are anticipated to be primarily combined-cycle combustion turbine plants due to their low capital cost. Retired coal plants are likely to be replaced with other technologies, and modifications to existing plants to mitigate emissions are expected as well. The overall net change in air quality at the end of 2015 for the No-Action Alternative is described in Figures 4.13 through 4.16. Section 3.2.1 describes the major air emissions affecting ambient air quality. Section 3.2.2 describes the pertinent regulations and factors affecting indoor air pollution, which may be affected by certain customer conservation programs.

3.2.1 Ambient Air Quality

This section, along with Appendix A, describes the general air quality of Western's service region and discusses related resources and populations that may be affected by changes in air quality. This section focuses on air quality issues related to the energy sector.

The Clean Air Act (42 USC 7401-7626) directs the U.S. Environmental Protection Agency (EPA) to regulate air pollutants that may endanger public health or welfare. The EPA has established a list of six criteria pollutants including particulates, sulfur dioxide (SO2), nitrogen dioxide (NO2), carbon monoxide (CO), ozone, and lead. These are called criteria pollutants because the EPA must compile scientific and medical information on their health and environmental effects in "criteria documents." This scientific information is then used to establish National Ambient Air Quality Standards (NAAQS) (40 CFR 50.4-50.12). Of these, particulates, SO2, and NO2 are common emissions from combustion electrical generators. In the atmosphere, these compounds can react with other pollutants and environmental factors to form ozone and acidic deposition. These criteria pollutants are described in detail in Appendix A.

In addition to criteria pollutants, carbon dioxide and hydrogen sulfide are also discussed in Appendix A. Appendix E describes emissions from different types of power plants. Carbon dioxide (CO2) is a major by-product of burning fossil fuels that may contribute to global climate change. Hydrogen sulfide (H2S) is a pollutant commonly released from geothermal facilities and during the extraction of oil and natural gas. Appendix A also briefly describes the Clean Air Act's treatment of volatile organic compounds and hazardous pollutants.

In 1990, Congress amended the Clean Air Act and directed the EPA to establish many new programs and regulations that will affect utility planning. The new law revises deadlines for states that do not meet the NAAQS to devise and implement plans for ozone, particulate, and carbon monoxide control. The amendments establish a market-based program for utilities to trade S02 emission allowances, and increase NOx regulation in areas not in compliance for ozone. New programs, regulations, and studies for each pollutant type, which may affect utility planning, are briefly described in this report.

The Clean Air Act requires states to designate all areas within their borders as being in attainment, nonattainment, or unclassified with respect to NAAQS for criteria pollutants (Moyer and Francis 1991). Table 3.1 lists the NAAQS for criteria pollutants. If an area is in nonattainment for a pollutant, the concentration of that pollutant is high enough that it may cause adverse health effects. Figure 3.9 shows the nonattainment areas for the states in Western's region. The figure is derived from state air quality reports (California 1991; Colorado 1990a; Montana 1991; New Mexico 1990; and Nevada 1988) and also personal contact with state environmental control agencies.1

Figure 3.9 Areas of Nonattainment for Air Pollutants in Western's Pollutants in Western's Region (Adapted from state air quality reports as described in Chapter 3.2)

Table 3.1 National Ambient Air Quality Standards

Table 3.2 Indoor Air Pollutants

Total suspended particulates (TSP) is included as a pollutant because Montana and Nevada still use that standard. (See the discussion of particulates in Appendix A.) Montana describes its areas with lead and PM10 emissions as being "out of compliance" with the standard instead of "in nonattainment" (Montana 1991). (PM10 refers to particulate matter of less than 10 microns in diameter.) Also, the nonattainment areas for California are classified relative to California State standards which are more strict than the NAAQS (California 1991). Note that the symbols represent the number of nonattainment areas per state and their approximate locations. Because the data on nonattainment areas varied (geographic dimensions of the areas varied from one portion of a city to an entire air basin), the map does not indicate the actual size of the nonattainment areas.

The environmental effects of these common air emissions are summarized in Appendix A. In addition to these common emissions, combustion generating plants may also emit heavy metals, radionuclides, and hazardous compounds from the combustion of specific fuel types. These and other pollutants specific to a particular type of power producer are listed in the profiles of the various generation types in Appendix E.

3.2.2 Indoor Air Quality

The quality of indoor air is dependent on the complex interaction between sources of indoor pollutants, building volume, and environmental factors within buildings such as temperature and humidity, the removal of air pollutants by air cleaning devices, and the removal and dilution of pollutants with outside air. These factors interact with other environmental considerations such as inadequate temperature, uncomfortable humidity, and poor lighting to affect occupants' perceptions of the indoor environment. One national survey reports that 25 percent of American workers feel that the quality of their work-place air affects their work adversely (Sheldon et al. 1988a). Woods (as reported in Levin 1989) found that 20 percent of the office workers in the United States may be affected by sick building syndrome (SBS). SBS refers to health and comfort problems associated with working or being in a particular building (EPA 1988), and generally applies to problems related to indoor air pollution, rather than stemming solely from humidity and temperature control.

To the extent that energy conservation measures may affect a number of these factors, the relationship between conservation measures and indoor air quality is difficult to predict. Energy conservation measures do not cause indoor air quality problems. However, if sources of pollutants are present indoors, some measures may contribute to elevated pollutant levels. Common indoor air pollutants and potential sources are listed in Table 3.2. Depending on the location of pollutant sources (indoor or outdoor), indoor pollutant concentrations may be either increased or decreased by a reduction in ventilation. For instance, additional caulking and weather stripping will reduce the infiltration/exfiltration rate. This reduction in ventilation may increase indoor pollutant levels originating from an indoor source because of a reduction in fresh air dilution and removal. But the same conservation measure will decrease the levels for a pollutant with an outdoor source by reducing the transport of that pollutant to the indoor environment.

Energy conservation measures may affect pollutant levels in other ways. Conservation measures, such as caulking and insulation, may introduce sources of indoor pollutants. Measures that reduce mechanical ventilation may allow pollutants to build up inside structures. Finally, heating, ventilating, and air-conditioning systems may provide surface areas for the growth of biogenic agents; they may also encourage the dissemination of pollutants throughout a building.

Conservation measures that involve carefully maintaining and operating mechanical equipment may improve the quality of indoor air. In some instances, proper operation will increase ventilation and thus improve pollutant removal mechanisms. Proper installation will help ensure that HVAC systems are delivering appropriate levels of ventilation.

Regular inspections will make the build-up of biogenic colonies in HVAC systems less likely by early detection of microbial growth in areas such as duct work near cooling coils; inspections may also reveal design deficiencies such as the placement of air intakes near sources of pollutants such as garbage storage areas or parking garages (Rask and Lane 1989; Morey 1988).

Caulking around windows could also improve air quality by eliminating the entry of wind-driven rain, which fosters the growth of molds and fungi (Rask and Lane 1989; Morey and Jenkins 1989).

A discussion of many of the factors affecting indoor air quality and a description of the potential impacts of indoor air pollutants is contained in Appendix A.

3.3 WATER QUALITY AND CONSUMPTION

Thermal power plants, those that burn fuels or use nuclear fission to produce electricity, use water for cooling and to produce steam. Water is taken from rivers, groundwater, coastal waters, or reservoirs and is recycled within the plant or returned to its source. Power plants also release effluents that may find their way into water bodies, although treatment plants can capture most of these pollutants. Table 4.1 lists the assumed water consumption and waste water release rates for the power plants analyzed in this draft EIS. Descriptions of power plant processes and effluents are contained in Appendix E. Estimates of impacts from water consumption and waste water production are presented in Chapter 4. This section describes the water quality of the rivers, lakes, and groundwater of the states in Western's region. Water pollution regulations and the current water quality status of the rivers, lakes, and groundwater in the states of Western's service region are described. A discussion of wetlands and marine waters (for California and Texas) is also provided.

3.3.1 Surface Water

Section 305(b) of the Clean Water Act (33 USC 1315) directs states to prepare a report every two years describing existing water quality. Tables 3.3 and 3.4 summarize pertinent information on river and lake water quality from the 305(b) reports of the 15 states in Western's region. The tables are derived from state water quality reports (Arizona 1990; California 1986; Colorado 1990b; Iowa 1990; Kansas 1990; Minnesota 1990; Montana 1990; Nebraska 1990; Nevada 1992; North Dakota 1990; South Dakota 1990; Texas 1990; Utah 1990; and Wyoming 1991) and also contacts with state environmental control agencies.1

Novick, Stever, and Mellon (1991) provide the following explanation of the Clean Water Act. The states must designate uses for which each body of water is to be maintained. Some examples of the uses are cold or warm water fishing, public drinking water supply, and agricultural water supply. EPA regulations require that, at a minimum, the designated uses specify that waters are fit for aquatic protection and recreation or are "fishable/ swimmable." States may give a lower designated use only if the water body is inhibited by natural environmental factors or if the measures necessary to achieve the use would result in "substantial and widespread economic and social impact." Such bodies of water are listed as not attainable.

State water quality criteria specify the concentrations of pollutants not to be exceeded to ensure that the designated uses are maintained. Tables 3.3 and 3.4 list the degree to which the water bodies of the 15 states support their specific designated uses and whether they meet the fishable/swimmable goals. Terms typically used in water quality reporting to indicate the level to which water bodies meet state-designated uses include "fully support,""partial support," and "not support." Some states also include a category for "threatened" designations. California uses corresponding categories of "good," "medium," and "poor."

3.3.2 Groundwater

Most of the states in Western's region report generally good groundwater quality without any widespread contamination, yet there are several pollution sources that do create problems. The pollutants contaminating groundwater may be naturally occurring but are usually related to human activity. Some of the major contamination sources that are common to many of the states are leaking underground storage tanks, solid waste, hazardous waste, agricultural activities, and waste water. Because groundwater contamination can come from several different sources, groundwater protection must involve many different groups. Most state monitoring and assessment programs are just now getting started.

Table 3.5 lists several different groundwater contamination sources. The table indicates states that have listed a particular source as a problem. The source categories are broad and may not be as specific as the state reported them.

For comparison, the source categories listed on Table 3.5 were combined as follows:

* Hazardous waste sites includes abandoned and regulated hazardous waste sites.
* Mining activities includes mineral processing; cyanide heap leaching; mine, mill, and smelter tailings or slag; and other mining activities.
* Road salting and salt water intrusion are combined.
* Oil and gas exploration and processing includes pipeline leaks, hydrocarbon storage

tanks, oil and gas exploration activity, and oil and gas brine pits.

* Waste water includes waste water impoundments and treatment lagoons, land application treatment, and septic systems.
* Solid waste includes municipal and industrial landfills.
* Agricultural applications include pesticides, fertilizers, and feedlots.
* Wells include inadequate well design, construction, and placement and leaking artesian wells and injection wells.
* Underground storage tanks, spills and leaks, and naturally occurring contamination are each listed as separate sources.

Groundwater quality is an important concern because groundwater sources are used for a large percentage of the domestic water supply. Table 3.6 gives the percentages of total water use supplied by groundwater for the states in Western's region.

Table 3.3 River Water Quality Summary

Table 3.4 Lake Water Quality Summary

3.3.3 Wetlands

A general definition of wetlands, as given by the U.S. Fish and Wildlife Service, is lands transitional between terrestrial and aquatic systems where the water table is usually at or near the surface, or the land is covered by shallow water. Information on the water quality of wetlands is not available for the majority of states in Western's region. The trend of major concern is loss of wetland acreage.

In the past, wetlands have been considered unimportant and many acres have been drained for agricultural use or development. This attitude has begun to change and the many benefits provided by wetlands are being recognized. These benefits include reducing pollutant levels, aiding flood control, recharging ground water, and providing wildlife habitat and recreational area. Several of the states in Western's region provide information on the amount of wetland acreage lost since pre-settlement times. That data is summarized in Table 3.7. Siting of energy facilities under the No-Action Alternative will likely avoid wetland areas to the extent possible due to siting regulations and wetland protection legislation.

3.3.4 Marine Waters

California and Texas are the only states in Western's region that have marine waters. The Clean Water Act requires states to designate uses for marine waters just as they do for rivers and lakes. These waters may include near-shore ocean waters, harbors and bays, estuaries, and coastal wetlands.

California - California has 1,073 statute miles of mainland coastline, 10 major bays, and nine major offshore islands totaling to 1,840 statute miles. California also has 86 areas of coastal wetlands covering 107,419 acres and 34 designated Areas of Special Biological Significance (ASBS) covering 422,248 acres (California 1986). An ASBS is intended to give special protection to marine life by prohibiting waste discharges within areas containing unique biological communities.

All but 1 percent of California's mainland coast was classified as good (California 1986). The 10-mile stretch making up the 1 percent classified as of poor quality is located at Imperial Beach south and is a recognized international problem originating in Mexico. Of the bay areas, 95 percent are classified good to medium, 1 percent is unknown, and 4 percent are poor. Classification for the coastal wetlands are listed as 41 percent unknown and 56 percent poor. All of the ASBS are classified as good.

Texas - Texas has designated and assessed 1,990 square miles of estuaries/ harbors/bays and 3,879 square miles of coastal Gulf waters. Of the estuary/ harbor/bay waters, 1,505 square miles are fully supporting their designated uses while 485 square miles are not supporting. All of these waters meet the swimmable goal, and all but 3 percent meet the fishable goal. All of the 3,879 square miles of Gulf waters are fully supporting their designated uses and meet both the fishable and swimmable goals.

Table 3.5 Sources of Groundwater Contamination

3.4 LAND USE AND SOLID WASTE

Land use issues related to electric power generation include changes to local development, recreation, and other use patterns caused by power plant and transmission facility construction, fuel source production and transportation, and waste disposal. The amount of land assumed in this draft EIS to be required for power plant siting is displayed in Table 4.1. Section 3.1 describes general vegetation and landform types found in Western's service region. Appendix E describes different types of power generating facilities and factors that may affect local land use, such as noise and traffic.

The effects of mining, processing, and transporting fuels for power plants are not quantified because specific sources that might be affected by the Program are not known. The same applies to transmission facilities.

Most of the solid waste produced by thermal electric power generation is ash from burning coal. Ash consumes landfill capacity and has the potential to contribute dissolved inorganic pollutants to surface and groundwater. Ash and other forms of solid and hazardous waste are described in Appendix E.

3.5 SOCIAL AND ECONOMIC ENVIRONMENT

The social and economic environment of Western's service region is complex and diverse. This section briefly describes population trends and projections, employment, cultural resources, and legislation that relates to utility planning or that may be affected by Western's alternative actions.

3.5.1 Population Trends and Projections

Population growth and decline are fundamental forces shaping utility loads and plans. Figure 3.10 shows state-by-state changes in population between 1980 and 1990. This figure also shows projections of population growth into the future. Figure 3.11 shows the current trend and projection of population for all states having any counties inside of the Western service area. Table 3.8 shows the 1992, point-in-time, breakdown of population across area office territories, compiled by summing the population of each county actually pertaining to a given area office. Summing the population column of Table 3.8 does not yield the 1992 point on the graph in Fig 3.11, because in some states, not all counties are in Western's territory. Detailed listings of metropolitan statistical areas and county population densities can be found in Appendix D. Regional utilities, including Western's customers, will have to respond to changes in demand for electricity because of their responsibility for meeting load growth.

Table 3.6 Percentage of Total Water Use Supplied by Groundwater

States	AZ	CA	CO	IA	KS	MN	MT	NE	NV	NM	ND	SD	TX	UT	WY
% Water Use	54	40	18	30	85	22^a	nr	b	nr	nr	60^a	50	61	b	nr

nr = not reported
^a percentage of drinking water supplied by groundwater
b percentage of use not given but listed as a critically important source
Source: Adapted from state water quality reports as described in Section 3.3.

Table 3.7. Wetland Acreage Loss Summary

States	AZ	CA	CO	IA	KS	MN	MT	NE	NV	NM	ND	SD	TX	UT	WY
% Lost	95^a	88^b	nr	97^c	40^d	68^b	nr	78^e	nr	33	50^f	35	nr	nr	38

nr = not reported
^a reported as areas lost or altered
^b calculated from given acreage
^c Calculated, given loss since 1906
^d reported as percent lost since 1955
^e reported as 22 percent remaining
^f reported as "nearly half has been drained"
Source: Adapted from state water quality reports as described in Section 3.3.

3.5.2 Employment

Figure 3.12 shows employment by industry for the Western region. Figure 3.13 shows the distribution of personal income (1990 figures) by state and major industries. Figure 3.14 shows employment trends and projections for the entire Western service area. Estimates of employment needs for constructing, operating, and maintaining electricity generators and conservation programs are shown in Table 4.1.

3.6 EXISTING UTILITY PLANNING ACTIVITIES

State planning and rate regulations typically apply only to investor-owned utilities while public utilities are generally controlled by a local governing board or city council and may need to meet the requirements of the Rural Utilities Service (RUS). An individual utility's planning requirements will depend on the state regulations that are in place. Even if public utilities are not regulated directly, state requirements may influence local practices. If some utilities develop aggressive DSM programs as a result of state requirements or their own planning, others may follow suit to satisfy their customers. Both public and investor-owned utilities are now practicing IRP.

In a nationwide survey of public utilities, Garrick et al. (1993) addressed seven specific IRP elements to determine the scope and extent of IRP practice. These elements are:

* load forecasting
* supply-side resource evaluation
* demand-side resource evaluation
* consideration of environmental and/or social externalities
* uncertainty (or risk) analysis
* integrated resource evaluation
* public involvement.

Figure 3.10 Population Changes in the States of Western's Service Region for 1980-1990 (actual) and 1990-2010 (projected) (U.S. Department of Commerce 1992)

Table 3.8 Population for Each of Western's Areas

Area Office	No. of States^a	No. of Counties	Population	MSAs
Billings	6	302	4649130	9
Loveland	4	173	5246367	11
Phoenix	4	29	21459400	8
Sacramento	2	63	13930200	20
Salt Lake City	6	179	6918882	16

^a Some states are served by more than one area office.
MSA = metropolitan statistical area
Source: U.S. Department of Commerce, 1992

Figure 3.11 Population Trends and Projections for Western's Service Region, 1969-2040 (U.S. Department of Commerce 1992)

The survey revealed that while most public utilities practice a majority of these elements, very few practice all seven. Three of the most common elements that utilities do not currently practice are consideration of externalities, uncertainty analysis, and public involvement. On the other hand, the most common elements public utilities practice are load forecasting and demand-side resource evaluation. The survey also found that, of those utilities that claim they do not practice IRP, many of them actually practice some, if not all of the IRP elements. However, their levels of scope are more limited and most of these utilities omit the "integrated resource evaluation" element. The majority of public utilities that practice very little or none of the IRP elements are distribution systems who currently receive 100% of their power from a wholesale supplier.

Public utilities practice IRP for reasons other than to fulfill state and federal regulations. Many utilities practice IRP because they consider it to be a good business practice with a sound planning methodology. Some employ IRP as a means to address environmental issues.

Figure 3.12 Distribution of Employment by Major Industry for Each State in Western's Service Region (1990 data) (U.S. Department of Commerce 1992)

Figure 3.13 Distribution of Income by Major Industry for Each State in Western's Service Region (1990 data) (U.S. Department of Commerce 1992)

3.6.1 State Regulatory Requirements for IRP

In a nationwide survey of state regulatory bodies, Mitchell (1989) rated the progress of all 50 states toward a "full-featured regulatory framework." A full-featured framework includes the following components:

* a legislative or regulatory requirement that each electric utility complete an IRP
* a public review process for the IRP
* integration of construction permits and rate-making with the IRP process.

Mitchell also considered whether the requirement has been implemented as a criterion in the rating scale.

In a more recent survey of public utility commissions, Lang and Hadel (1994) found that 40 states across the country have adopted IRP for electric utilities either formally or informally. They indicate that those states that have yet to adopt an IRP process are either considering or evaluating the need for an IRP process, or have significant excess capacity. Lang and Hadel attribute the number of these processes as a function of the Act which explicitly encourages all utilities to conduct IRP (Lang and Hadel 1994).

Of the 15 states in Western's territory, eight or nine have legislative or administrative IRP requirements in place, two are currently in the process of developing plans, two are considering requirements, one state has no IRP requirement and is not formally considering a requirement, and one state does not regulate its utilities at the state level. Many of Western's customers are unregulated and are not subject to existing state IRP requirements. Mitchell (1992) rated California and Nevada, as having "adopted and implemented" a full-featured IRP process. California requires many of its public utilities to submit demand and load forecasts, as well as some alternative scenario analyses.1

Iowa has required its utilities to submit an Energy Efficiency Plan since 1991. The plan may incorporate all of the components of an IRP, according to a PUC staff member.2 They may provide a "set of rules" that are employed in phases. Currently, utilities are in a cost-recovery phase and are evaluating the results from their first two years in the plan and applying for shared savings. Other phases include submitting a cost-effective proposed program, implementing minimum mandated programs at mandated spending levels, and board approval. Furthermore, a special commission is in place to determine whether or not an energy efficiency plan is the equivalent of an IRP.

Wyoming does not have an IRP requirement in place, but utilities are required to file IRPs on a case-by-case basis as ordered by the PUC. 1

No formal policy has been adopted in either North or South Dakota; however, both states are considering the possibilities, and will make a decision by October of 1995 at the latest. South Dakota does require jurisdictional utilities to file 10-year plans every two years. Both states also indicated that most of their utilities already submit IRPs to meet requirements of other jurisdictions that they cover.2

The Arizona Corporation Commission requires preparation of IRPs only for generating utilities, whether publicly or investor-owned.3 Salt River Project does an IRP voluntarily but it is not regulated. Texas requires some of its municipalities to do some load forecasting and assess conservation resources.4

As part of the DOE-sponsored program "Advancement of IRP in Public Power," the National Renewable Energy Laboratory (NREL) and a subcontractor conducted a survey on public utilities in the country by federal service regions.5 Two types of government-owned utilities (joint-action agencies and municipal utilities) and two types of cooperatively-owned utilities (generation and transmission (G&T) cooperatives and distribution cooperatives) were surveyed. According to the survey, seven out of the nine joint-action agencies surveyed in Western's service territory (out of a total possible of 13) currently prepare IRPs, driven primarily by federal or st ate requirements. Out of the 74 municipalities in Western's area that responded to the survey (out of a total possible of 364), 22 prepare IRPs. G&T cooperatives in Western's service area that prepare IRPs stated that the major drivers were federal PMA requirements. The majority of distribution cooperatives practice resource planning with their G&T cooperatives or other power suppliers, and very few prepare their own IRPs.

Table 3.9 summarizes the current status on IRP requirements for each of the states in Western's service region (Mitchell, 1992).6 Four categories for the status of IRP requirements are possible:

* In place: An IRP requirement is in place.
* Development: Draft IRP rules are being written or reviewed, but no requirement is in place.
* Consideration: There is awareness of IRP in the PUC but no formal plans to institute a requirement.
* Not considered: The state has no plans to initiate an IRP requirement.

Table 3.9 Status of State Regulatory Agency IRP Requirements in Western's Region

Figure 3.14 Employment Trends and Projections for Western's Service Region, 1969-2040 (U.S. Department of Commerce 1992)

In a 1992 update, Mitchell also looked at advanced issues in IRP, such as DSM. Similarly, in a 1992 report, the National Association of Regulatory Utility Commissioners (NARUC) listed the state commissions that provide incentives for electric-utility investments in DSM programs. According to the report, Arizona, Idaho, and Iowa have cost recovery mechanisms in place by generic commission order. Kansas, Montana, and Texas have mechanisms in place by statute. Although in 1992 Utah did not have any formal mechanism in place, a more current conversation with a PUC staff member from Utah revealed that they are at a "modest beginning." 1 Three categories for the status of DSM cost recovery mechanisms are possible and shown on Table 3.9 :

* In place: formal action (regulatory decisions or legislation) has been taken to provide lost-revenue recovery and/or shareholder incentives
* In progress: a formal proceeding to consider providing lost revenue recovery and/or shareholder incentives is in progress
* No action: absence of formal action to provide lost revenue recovery and or/shareholder incentives.

The Association of Demand-Side Management Professionals (ADSMP) (1993) provided an overview of the current status of regulatory requirements to address environmental externalities in utility resource planning and/or acquisition. Externalities are costs or benefits of an action that fall outside the scope of traditional cost/revenue accounting. (See Section 2.1.1.1) Environmental externalities are costs or benefits to the natural environment, and are often difficult to quantify. The states are rated on a three-point scale for the status of their treatment of externalities:

* Existing requirements: the state has developed and applied rules or approaches for externalities, either qualitatively or quantitatively.
* Considering requirements: there are no rules or approaches in place, but are being considered.
* No requirements: there are no requirements in place and none are being considered.

States that have existing requirements in Western's territory are Arizona, California, Colorado, Iowa, Minnesota, Montana, Nevada, Texas, and Utah. Kansas and New Mexico are considering requirements according to the study. North Dakota, South Dakota, and Wyoming do not have any requirements in place.

ADSMP (1993) distinguishes two approaches for incorporating environmental externalities: quantitative or qualitative. A qualitative approach requires recognition of environmental externalities without requiring specific measures of cost. Arizona, Colorado, Minnesota, and Texas use a qualitative approach. Quantitative requirements usually involve some guidelines from the PUC (or other responsible agency) for estimating costs, which can be anything from estimated mitigation costs for external damages, to point systems, to putting the burden of proof on the utility and requiring the utility to provide justification for its cost estimates (Cohen et al. 1990). See the externalities discussion in Section 2.1 for additional information on reporting environmental costs.

In states where the IRP rules have been passed only recently, practical criteria for acceptance of plans are not yet known and neither the utilities nor the PUC have any experience with the IRP process as yet. By contrast, utilities in states with older IRP rules have already completed one or more IRPs and are familiar both with the PUC criteria and standards, and the staffing and resource needs to prepare a plan. Arizona, California, Nevada, Minnesota, and Texas have had IRP rules in place since 1989. For these states, therefore, it can be assumed that IRP is "in practice" for the affected utilities. Colorado, Iowa, and Montana, have more recently passed IRP rules and are either beginning or just completing their first review processes. Table 3.9 has details on the stage of compliance for these states.1

3.6.2 Rural Utilities Service Regulations

The RUS makes and oversees loans and loan guarantees for the construction of electric generation, transmission, and distribution facilities (including system improvements and replacements) necessary to supply rural areas with "adequate electric service." According to the 1936 Rural Utilities Service (RE-Act) (49 Stat. 1363 as amended), a RE-Act beneficiary is "a person, business, or other entity located in a rural area." A rural area is defined as "any area of the United States... not included within the boundaries of any urban area as defined by the Bureau of Census." (7 CFR, Section 1710 (a)). The RUS sometimes finances loans for non-RE-Act beneficiaries, if it decides that the loan is necessary for the entity to provide or improve electric service to rural areas not already adequately served.

The RUS recently adopted a rule requiring steps similar to the IRP process for its borrowers, called the "General and Pre-Loan Policies and Procedures Common to Insured and Guaranteed Electric Loans" (56 FR 8234 (February 27, 1991)). A major purpose of the new rule is to alleviate the problem of financially insolvent borrowers by strengthening credit policies. The RUS requirement has five parts: the Power Requirements Study (PRS), the PRS Work Plan, the Construction Work Plans (CWP), the Long-Range Financial Forecasts, and the Power Cost Study. No borrower is completely exempt from the rule, though it applies differently to different types of RUS borrowers.

3.6.2.1 Power Requirements Study

All RUS borrowers are required to submit a PRS with their loan requests. Borrowers that are Western's customers are typically cooperatives. The PRS reports current electric loads of borrowers, and thorough analysis of the factors affecting those loads, in order to forecast as precisely as possible the future electric loads and accompanying energy and capacity requirements. Power supply borrowers must incorporate the current and forecasted energy and capacity data from their member systems as well, if applicable (7 CFR, Section 1710.200, "Purpose").

Large power supply borrowers (total assets greater than $100 million) and all their members regardless of size (power supply and distribution borrowers), as well as large unaffiliated distribution borrowers, must prepare a new PRS, and gain RUS approval of the study, at least once every three years. Borrowers must also prepare annual updates containing any new data and/or assumptions. All borrowers, including small power supply borrowers who are not members of a large power supply borrower, and unaffiliated distribution borrowers, must submit a current PRS with any request for RUS loans or

RUS approval of long-term contracts, or with any other action that RUS considers appropriate (7 CFR, Sections 1710.201(a), 201(c), 201(b), 202(b), and 202(b)(2)).

Large power supply borrowers must also prepare a PRS Work Plan for themselves and their member systems, detailing resources, schedules, and milestones for preparing and updating the PRS (7 CFR, Section 1710.202(a) and 204(a)). The RUS may require the borrower to prepare a new or revised work plan if "the existing plan will not result in a satisfactory PRS on a timely basis" (7 CFR, Section 1710.204(a)).

Criteria for approval of a PRS include:

* analysis of all relevant factors influencing electricity consumption and generation and transmission requirements
* accurate analysis of RE-Act and non-RE-Act beneficiary needs
* adequate supporting data, valid assumptions, analysis of relevant alternative scenarios and assumptions, and use of valid and verifiable techniques and models
* adequate documentation and assistance for review
* demonstration of adequate coordination of work plan and PRS preparation with member systems where applicable
* recommendation for approval by borrower's general manager and board of directors.

With the written request of the borrower's general manager, the RUS's Administrator is allowed to waive any of the PRS requirements, if "good cause is shown" that the requirement places "a substantial burden on the borrower," and the waiver will not prevent the accomplishment of the objectives of the PRS rules (7 CFR, Section 1710.206), primarily forecasting of future electric loads and future energy and capacity needs.

3.6.2.2 Integrated Planning System for Facility Development

To address borrowers' short-term and long-term needs for plant additions, improvements, and replacements, the proposed rules include a continuing coordinated planning system. The planning system consists of long-range engineering plans, CWP, and special engineering and cost studies (7 CFR, Section 1710.250(a)). All borrowers must keep current, approved long-range engineering plans. Current, approved CWPs must be kept for transmission and distribution facilities and for generation facility improvements or replacements, and any request for RUS financial assistance for these facilities must include a current, approved CWP (7 CFR, Section 1710.250(b)). Special engineering and cost studies are prepared for any generation capacity additions (constructed or purchased) and associated transmission plant additions, and to support CWPs.

Long-term plant investment needs are projected in the long-range engineering study covering a period of 10 years or more. Plant investment needs are defined as "the major system additions, improvements, replacements, and retirements needed for an orderly transition from the existing system to the system required 10 or more years in the future" (7 CFR, Section 1710.250(c)). The future system should meet the borrower's projected long-term loads in a manner that is the most economically and technically sound, as well as reliable and environmentally acceptable.

The CWP reports short-term plant investment requirements covering a period of two to three years. The CWP includes estimates of investment cost and special engineering and cost studies. Special engineering and cost studies support the CWP, and "identify and document requirements for specific additions of generation capacity and associated transmission plant" (7 CFR, Section 1710.250(a) and 250(d)). All facilities in a CWP or CWP amendment must gain RUS approval before the start of construction. The RUS can adjust cost estimates in a CWP if the RUS disagrees with the original estimate (7 CFR, Section 1710.250(e) and 250(f)).

Proposals for new generating capacity must be accompanied by specific engineering and cost studies, including present-value economic analyses of costs and revenues from self-generation, load management, conservation, and purchased power, as well as assessments of the reliability and financial risks of each option (7 CFR, Section 1710.253(a) and 253(b)). The proposed rules do not include specific guidelines for conservation and load management, stating only that "borrowers are encouraged to promote the efficient use of electric energy and to promote load management to improve system load factors, to reduce losses, to use existing facilities more effectively, and to reduce the need for new generating facilities" (7 CFR, Section 1710.118).

The RUS is responsible for NEPA compliance for projects it initiates or that are receiving the agency's funding.

3.6.2.3 Alternative Power Sources

The RUS will approve financial assistance for adding generation capacity only if the applicant has investigated alternative power options. The applicant must solicit proposals from all reasonable power sources, including cogenerators and independent power producers. These alternative sources of power must be analyzed in terms of cost-effectiveness, reliability, the short- and long-term financial condition of the supplier, and "financial risk to the borrower and its creditors" (7 CFR, Section 1710.254(a), 254(b), and 254(c)).

3.6.2.4 Long-Range Financial Forecasts

Borrowers are encouraged, but not required, to keep a current long-range financial forecast. This forecast is required, in support of any loan application to RUS, to demonstrate the economic viability of the borrower and the financial feasibility of the loan (7 CFR, Section 1710.300(a) and 300(b)). All borrowers are required to prepare financial forecasts in support of loan applications. Financial forecasts must include:

* planned future actions by the borrower's board of directors
* goals for margins, TIER, DSC, equity, and levels of general funds 1
* for each year in the forecast period, a pro forma balance sheet, statement of operations, and general funds summary
* explanation of assumptions, methodology, data, and analysis used in the forecast for all projected values influencing the balance sheet and financial ratios
* cash flows and estimates of future borrowing and borrowing expenses
* current and projected energy sales, prices, wages, interest, operating costs, revenues, and other nonoperating income and expenses
* analysis of potential effects of future rate increases and, for power supply borrowers, analysis of the borrower's ability to compete with other nearby utilities.

The CWP and the PRS must be used in preparing the long-range financial forecast, as well as current rate schedules and assumptions regarding future plant additions at future cost levels using an anticipated inflation rate. Also the forecast must include a range of assumptions for each of the significant variables to facilitate sensitivity analyses of the assumptions.

3.6.2.5 Power Cost Studies

Power supply borrowers are also required to prepare power cost studies to support all requests for financing of additional generation capacity and associated bulk transmission facilities. This study shall demonstrate that the proposed additional facilities "are the most economical and effective means of meeting the borrower's power requirements" (7 CFR, Section 1710.303(a)). The required elements of this study are essentially the same as those for the engineering and cost studies described in association with the CWP, except that power cost studies must also include sensitivity analyses of the assumptions.

3.7 WESTERN'S CUSTOMERS AND RESOURCE BASE

This section discusses the broad characteristics of Western's customers and resources available for marketing. Section 3.7.1 describes Western's customers. The generating resources within Western's service region are discussed in Section 3.7.2. Section 3.7.3 discusses regional loads. Section 3.7.4 describes current DSM and conservation activities. Section 3.7.5 discusses retail electric rates for Western's customers.

3.7.1 Western's Customers

According to the Act, the terms "customer" or "customers" mean any entity or entities purchasing firm capacity, with or without energy, from the Western Area Power Administration under a long-term firm power service contract. Such terms include parent-type entities and their distribution or user members. Western also markets surplus power when available to several nonfirm power customers.

Western markets and transmits Federally produced electricity over a broad geographic region comprising 15 states in the western part of the nation. Western has the largest service area of any of DOE's power marketing agencies in the continental United States, with the region having a combined population in excess of 45 million. In accordance with Federal legislation, preference in the marketing of power is given to municipal entities and other public corporations, and to Federal and state agencies. Preference customers also include cooperatives and other public organizations financed totally or partly by loans made under the RE-Act and amendments to that legislation. To a far lesser extent, Western also engages in power transactions with investor-owned utilities.

With the general exception of some Federal and state agencies and irrigators, Western's customers are utilities that have distribution systems to operate and maintain in order to serve their loads. Some of these customers may own, or have shared interest in, generating plants while others rely totally on Western and other sources for power to meet their native load requirements. In a number of instances, preference customers have formed MBAs in an arrangement where the association is the "customer" of Western, and possibly of some other power supplier as well. In some cases, members have assigned their Western entitlement to their affiliate MBA, which then is viewed as one customer of Western, though, in fact, many entities are represented.

Systemwide, the distribution of these broad classes of customers is shown in Figure 3.15. Over one-half of all customers (55 percent) are cities or towns. Cooperatives (co-ops), public utility districts (PUDs), and irrigation districts account for another 20 percent of the customer base. Although investor-owned utilities do not have preference status, one is represented because it has a direct allocation of Federal power.

Figure 3.15 Western System Firm Power Customer Class Distribution (Western 1991b)

Municipalities are less dominant when energy delivery to Western's major customer groups is considered as shown in Figure 3.16. Energy deliveries represent both Federal project net generation and purchases by Western on behalf of its customers. Co-ops, PUDs, and irrigation districts together account for 43 percent of sales despite being only about one-fifth of the entire customer base.

Figure 3.17 shows a breakdown of the number of customers and their relative share in each area's customer base for Billings, Loveland, Salt Lake City, Phoenix, and Sacramento, respectively. The dominance of municipalities among Western's customer types is attributable to the large number found in the Billings Area Office. Figure 3.18 shows the distribution of energy of Western's customer classes by area office. Municipals, co-ops, and PUDs receive nearly 95 percent of the Federal energy marketed through the Billings Area Office. In the Loveland Area, co-ops receive more than half of the Federally marketed energy. In the Phoenix marketing area, state agency service (predominately to the Arizona Power Authority and to the Salt River Project) represents the single largest type of customer load at 47 percent. Despite being only 13 percent of Sacramento's customer base, municipalities represent nearly half of Western sales in the Sacramento Area Office (47 percent in Figure 3.18). This is largely due to the Sacramento Metropolitan Utility District, which is traditionally Western's largest single customer. In its Salt Lake City Area Office, Western's co-op customers account for nearly half of all mar keted energy, and municipals account for nearly another 40 percent.

A complete listing of Western's customers is provided in Western's most recent Annual Report.

3.7.2 The Western Resource

Western markets and transmits power and electric energy from 54 Federal hydroelectric power plants and the Federal share of one thermal power plant in 15 western states. The combined maximum operating capacity of these plants is about 10,600 MW and they produce on the order of 35 million MWh of average annual output. The major Federal projects in Western's region include the Boulder Canyon, Central Valley, Collbran, Colorado River Basin, Central Arizona, Falcon-Amistad, Fryingpan-Arkansas, Parker-Davis, Pick-Sloan Missouri Basin, Provo River, Rio Grande, and Washoe hydroelectric power projects; a portion of the Navajo steam plant; and the Pacific Northwest-Southwest Intertie (Western 1991a). Federal power plants in Western's region are shown in Figure 3.19. These projects are operated by the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, or the International Boundary and Water Commission, depending on the authorization of each project from Congress. Western's capability to efficiently market this Federal power is also supported by a considerable investment in an expansive network of high-voltage transmission lines, area control centers, switch yards, and substations.

3.7.2.1 Regional Generation Capabilities

The total installed generation capacity in the Western region is nearly 125,000 MW. The Phoenix Area accounts for the largest share, about 46,000 MW. The Salt Lake City Area is the second largest in installed capacity with nearly 28,000 MW, followed by the Sacramento Area, which covers northern California and all but the southern portion of Nevada with over 22,000 MW. The Loveland Area's total generation capacity is nearly 11,000 MW and Billings' marketing area contains approximately 18,000 MW. These amounts are reported by owner type as the area office sub-totals in Table 3.10. Table 3.10 shows nameplate capacity by actual geographic location.

Figure 3.16 Western Area Energy Distribution to Firm Power Customers by Customer Class (Western 1991b)

Figure 3.17 Firm Power Customer Class Distribution for Each Western Area Office (Western Division of Rates, Rates and Statistics Branch, 1993)

There are seven broad classes of major generation plants in the Western region: fossil fuel-fired steam, combined-cycle combustion turbine, nuclear steam, geothermal, hydroelectric, and renewable resource units. All five areas have significant amounts of emergency backup internal combustion generation. Table 3.10 also contains the breakdown of these broad generation types by area office and by form of ownership. Of the total capacity, 63 percent is from fossil steam plants built before 1985. 1985 is a commonly used breaking point to differentiate between older installed coal-fired units and newer plants that incorporate state-of-the-art technology. Nuclear steam plants represent 8 percent of total capacity, and Federal and non-Federal hydroelectric resources account for another 9 percent each. Combustion turbine plants have a 6 percent share of total capacity in the 15-state region and post-1985 fossil fuel-fired steam plants account for 4 percent. The relatively new, commercial size technologies of geothermal and combined-cycle plants provide about 2 percent each. There is one major renewable resource facility in the Phoenix Area, a solar generation site with a capacity of 209 MW. The Sacramento Area posesses considerable renewable energy technologies in the form of geothermal resources and some wind-energy forms.

Figure 3.18 Energy Distribution by Customer Class for Firm Power Customers in Each Western Area Office (Western 1991b)

The combination of generation types used varies significantly across each of Western's areas. The actual mix results from a complicated set of relationships managed by system planners that involves peak and average loads, the cost and performance features of supply-side resources, DSM measures, reliability criteria, state and Federal regulatory influences, form of utility organization, and environmental aspects. Notwithstanding these complexities, what is currently observed is that the dominant portion of capacity is provided by fossil steam plants built before 1985 in each of the five areas. Phoenix has the broadest combination of resources, having in place all seven generation types. Nevertheless, pre-1985 fossil steam plants still account for over half of the total capacity (61 percent).

Sacramento Area resources reflect a more uniform representation of generation types with 35 percent of capacity coming from pre-1985 fossil steam plants, 33 percent from non-Federal hydroelectric plants, and 24 percent shared among nuclear steam, geothermal, combustion turbine, and post-1985 fossil steam plants. The remaining 8 percent is from Federal hydroelectric plants marketed by Western. Generation resources in the region covered by the Salt Lake City Area Office are largely accounted for by four of the broad types of plant, with a very substantial portion (78 percent) of total capacity from pre-1985 fossil steam plants.

Systemwide, a dominant portion (62 percent) of the generation capacity is owned by investor-owned utilities, with 28 percent owned by generating public utilities and roughly 10 percent Federally owned and marketed by Western. Investor-owned utilities own the majority of the capacity within each of the five areas, as well, with shares ranging from a high of 76 percent in the Sacramento Area to a low of 42 percent in the Billings Area. The Federal share of generating capacity in the area offices ranges from 15 percent in the Billings Area to 7 percent in the Salt Lake City Area. Figure 3.20 offers a quick comparison of the Federal resources marketed by Western relative to investor-owned and public utilities system wide.

Figure 3.19. Power Plants in Western's Marketing Area (Western 1991b)

Figure 3.20. Ownership of Capacity in Western's Region

Table 3.10 Summary of Generating Capacity by Western Area Office and Type

3.7.2.2 Western's Marketable Resource Capability

The numerous and varied projects from which Western markets power were often authorized with a number of purposes in mind. These broadly encompassed irrigation, flood control, navigation, and power, but often also included recreation and fish and wildlife restoration. Each of these purposes exerts an influence on how the project is operated in the context of a highly coordinated, interconnected set of power plants and utilities. As a result, the amount and types of power resources that Western can market from a particular project are the result of a complex set of calculations. These calculations account for a wide and varied range of conditions that affect the resource capability of the power plants and, sometimes, the interrelationship between plants in the same drainage basins or rivers.

Western coordinates with the agencies that operate the hydroelectric power plants to develop the information necessary for determining the amounts of project capacity and energy it has at its disposal to market to preference customers. The operating agencies maintain detailed databases of river basin hydrology and water utilization. Computer simulation models have been collaboratively developed by agency staff for the major river basins/projects that incorporate operating rules for the rivers which, in combination with the historic river flow data, permit the estimation of conditions affecting the supply of water, water elevations at reservoirs, flood control, recreation facilities, and electric capacity and energy.

The area offices of Western rely on these estimates of the future quantities of capacity and energy to determine the marketable amounts and types of capacity and energy for allocation to preference customers. These estimates become the basis for the contract agreements between Western and its customers.

The marketing criteria and contracts specify capacity and energy that are committed on a long-term, firm basis, with any additional capacity and/or energy offered either on a short-term firm basis 1 or on a spot-market basis. The quantities of spot-market sources available are generally not specified in the marketing criteria or contracts with customers receiving these services, but conditions and mechanisms governing their disposition may reside in the contracts.

Table 3.11 is a summary of the long-term firm capacity available for marketing through each of Western's area offices. While these figures are based on specific project capability and river system simulations, the capability of several projects is marketed through more than one area office. The table reflects area office marketable capacity to permit a better match with regional resources for the Program impact analyses. The long-term firm capacity of each major project that is available for marketing is determined using different hydrological conditions and criteria among each of the areas in which the project resides. A brief description of the planning criteria employed by each area office will illustrate the complexity and attendant uncertainties of quantifying the amounts of capacity and energy to which Western can commit on behalf of its preference customers.

Table 3.11. Western Marketable Capacity in each Area

Area	Marketable Capacity-Summer(MW)	Marketable Capacity-Winter(MW)	Criteria
Billings	1984	2012	Modified Adverse
Loveland	1147	1104	90% Exceedance
Phoenix	2845	2792	Maximum Plant Capability
Sacramento	1152	1152	Adverse
Salt Lake City	760	822	90% Exceedance

1 Short-term sales are contingent upon adequate water supplies.
2 Pre-empted under the Interim Post-1989 Power Marketing Plan.
Source: Draft EIS report on Capacity and Energy Available for Marketing prepared in July 1991 by the Western Area Power Administration' s Division of Power Resources; also, correspondence with Mike Cowan of Western's Power

The Billings Area relies on a modification to an "adverse" hydrological condition to quantify marketable, long-term capacity for the Eastern Division of the Pick-Sloan Missouri Basin Program. This condition entails removal of an extremely dry period from the historical record on river flows prior to developing expected future capacity availability. The most adverse water conditions in this modified water history are used as the basis for long-term, marketable capacity. Adjustments to project capacity under "modified-adverse" water conditions are made to determine the net available capacity for allocation by Western. These adjustments include additional capacity from diverse off-system sources and deletions for reserves, plant use, and project use. Any shortfalls in project capability below the long-term, firm commitment are purchased by the area office.

The Loveland Area markets capacity from the Western Division of the Pick-Sloan Missouri Basin Program and the Fryingpan-Arkansas Project and administers contracts for a portion of the SLCA/IP. The long-term, firm capacity portion from the Western Division Pick-Sloan Program is predicated on a 90-percent exceedance basis, indicating that level of capacity capability is expected to be available nine out of 10 times on a random basis. Long-term capacity from the Fryingpan-Arkansas Project's Mt. Elbert, a pumped-storage facility, is based on the plant's maximum capacity availability rating. Loveland Area customers of Western bear the financial risk of a shortfall of generation capability below the long-term, firm commitment. This risk manifests itself through either a reduction in capacity due to a shortfall or by accepting the increased cost of Western's purchase of capacity on a pass-through-cost basis.

The Phoenix Area markets output from the Parker-Davis Project, the Boulder Canyon Project, and approximately one-quarter of the capacity of the coal-fired Navajo Project and administers a portion of the SLCA/IP. Long-term, firm capacity available from Parker-Davis is based on maximum plant capacities for each of the summer/winter seasons. These are directly a function of expected reservoir elevations resulting from required water releases at Hoover Dam. The Parker-Davis Project contract customers assume the risk of any shortfalls below long-term, firm commitment levels. Title I of the Hoover Power Plant Act of 1984 defines the Boulder Canyon Project's marketable firm capacity. The capability of the Hoover power plant is marketed on a contingent basis in that the firm capacity is offered conditionally based on its availability. Western's Phoenix customers also assume the risk from reduced storage and/or reduced water releases from the Hoover plant. The Phoenix Area Office also markets the capacity of the Federal enti tlement to the Navajo steam generating plant, minus the Central Arizona Project pumping load.

The Sacramento Area bases its long-term, firm commitable hydroelectric capacity from the power plants associated with the Central Valley Project as supported by power purchases and a contract with the Pacific Gas and Electric Company (PG&E). The Central Valley Project bears all of the responsibility in meeting the long-term firm commitment. In the event that there is insufficient capacity to meet these commitments, the Sacramento Area must purchase capacity as needed to remedy the shortfall.

The criteria used by the Sacramento Area to market resources are based upon Sacramento's Contract for the Sale, Interchange, and Transmission of Electric Capacity and Energy, Contract 14-06-200-2948A (2948A), with PG&E. Contract 2948A is a unique, CVP projectwide integration contract that addresses the amount of Central Valley Project obligation PG&E will agree to support. In addition to considering the hydroelectric generation of the Central Valley Project, 2948A also takes into account the power purchased and used by the Central Valley Project, particularly that authorized for import on the Pacific Northwest-Pacific Southwest Intertie. The contract was established in 1967 and continues through 2004, unless terminated under certain conditions by either party upon four years' notice.

The Salt Lake City Area has determined its long-term, firm capacity resources for marketing pur-poses on the basis of a 90-percent exceedance level for the Colorado River Storage Project. This criteria means that 90 percent of the time a certain minimum level of capacity is assured or available. However, this capability is clouded by the uncertainty surrounding Colorado River Basin environmental issues and court decisions. The Collbran and Rio Grande Projects are now integrated with the Colorado River Storage Project to create the SLCA/IP. Both have their long-term, firm capacity determined on the basis of maximum capability. In the event that available capacity is less than the long-term commitment, Western will purchase capacity up to the level on which the commitment for firm capacity was based, as finally determined pursuant to the Record of Decision for the SLCA/IP electric power marketing EIS.

All of Western's areas use either a median or an average water criterion as the primary basis for quantifying the amount of energy to be committed on a long-term firm basis. Median water conditions mean that 50 percent of the water years that are in the history of stream flows are below this flow and 50 percent of the water years are above. Average water conditions are a simple weighted average over all of the water years in the historical record of stream flows.

In the Billings Area, energy commitments are based on median water, and the Area purchases energy to make-up shortfalls, as necessary. The Phoenix Area relies on average water conditions for both the Parker-Davis and Boulder Canyon projects. Western's customers in the Phoenix Area Office assume the risk of any generation below firm energy commitments, just as they do under the contingent firm capacity commitment. Energy commitments in the Loveland Area are tied to average water conditions for the Western Division of Pick-Sloan, and to an average of the annual "flow-through" water for the long-term, firm commitment from the Fryingpan-Arkansas Project. Support energy for Western customers in the Loveland Area is purchased on a pass-through-cost basis up to their contract rate of delivery and historical seasonal load factor. The Sacramento Area uses average water for its long-term energy commitment, plus 3,000 GWh of imported energy over Western's portion of the Pacific Northwest-Pacific Southwest Intertie. The marketing of energy is, like the Sacramento Area's capacity marketing, linked to the Sacramento Area's contract 2948A with PG&E. The marketing of the SLCA/IP is currently based on historic levels of capacity and energy commitments.

3.7.3 Regional Loads

Figures 3.21 and 3.22 show how Federal energy marketed by Western is distributed by wholesale-customer type across the Western region and across the area offices, respectively. As an intermediate step to the utility impact analysis, this usage needs to be embedded in a representation of total loads in each region. Total loads would be those served in the service territories of investor-owned and public utilities. The energy marketed by Western goes predominantly to serve the retail loads of the latter. Regional energy usage by major customer class for each of the regions covered by Western's Area Office is summarized in Table 3.12 for the year 1990. Figure 3.21 provides a ready comparison of the absolute levels of electric energy usage across Western's areas.

Regional loads are built up by customer class using the buildings sector model for the five areas based on the F. W. Dodge database (Dodge 1991), which is the basis for the buildings data summarized in Table 3.13. The combination and quantity of building types in a utility's service area are important aspects of planning. The buildings served by a utility make up a substantial portion of load and also determine many of the conservation and other strategies available for DSM programs.

For loads that are not building-related, such as the irrigated agriculture pumping load, an alternative estimating method was necessary. For agricultural loads, data on irrigated acreage were combined by area with data on energy use per acre to develop total gigawatthours of energy usage. Agricultural energy use that is building-related is contained in the commercial sector if it is a wholesale/retail activity (e.g., warehouse, feed store, or farm supply store) or in the residential sector if it is a dwelling (farm house). Industrial energy consumption is predominantly used for manufacturing processes. These loads are used to develop an average price paid per kilowatthour and total expenditures on electricity by area.

A report to Congress offers the following information on buildings (Bradley, Watts, and Williams 1991). Nationwide, electricity is the major form of energy used in residential and commercial buildings, although in most markets, natural gas is the leading fuel for space and water heating. Space heating, water heating, and refrigeration account for almost 70 percent of residential energy end use. In the commercial sector, space heating, lighting, and air conditioning are the largest energy end uses. More than 90 percent of air conditioning uses electricity.

Building energy use is generally a smaller percentage of the overall consumption in industrial settings. Manufacturing accounts for 29 percent of U.S. energy use. End uses include steam production, process heating, machine drives, electrolytic processes, and feedstocks.

Table 3.13 summarizes the buildings inventory for each of Western's area offices. The table lists the existing building stock in 1990 and estimated additions (less retirements) for 1990, 1995, 2005, and 2015. The table includes buildings found in all utility types, including investor-owned utilities, within each area office's service area. These estimates are important to the analysis of environmental impacts, which is described in Chapter 4. The buildings inventory is used to develop load estimates for each utility type in each area offices and to estimate buildings-related, DSM opportunities.

State and local building codes have an important bearing on the effect that new buildings have on utility loads. Currently, California has an aggressive code for both residential and nonresidential buildings. The Energy Policy Act of 1992 requires that all state compare their codes with model energy-efficiency codes. States must adopt more energy-efficient codes if they determine it is beneficial to do so.

Table 3.14 shows irrigated acreage related energy consumption for each state and area office in Western's region.

Traditionally, the residential customer class consumes roughly 30 percent to 40 percent of the electricity on a representative system or service territory; industrial consumption represents anywhere from 20 percent to 40 percent. The balance comprises commercial sector usage and other uses such as irrigation and public entities.

Figure 3.21 reveals a distribution of usage across Western's areas that conforms closely with the above rules of thumb. The customer class shares across the Salt Lake City, Billings, and Loveland Areas are very similar. As would be expected, the heavily populated Phoenix and Sacramento Areas account for a dominant share of the agricultural load for the entire Western region. Figures 3.22 and 3.23 give the customer class energy use within investor-owned and public utilities, respectively.

For investor-owned systems, the customer class load shares mirror closely those at the regional level. Customer class load shares in areas served by public utilities reflect slightly more variation, as the load level blocks in Figure 3.23 show. This stems essentially from public loads being a smaller share, as well as being smaller systems on average. These aspects, coupled with unique physical characteristics which may account for an imbalance in load mix, suggest that conventional rules of thumb may be less reliable for these systems. The figure reflects differences in the load composition of the public systems by area office. For example, in the Billings Area, residential and commercial loads dominate, which likely reflects the area's rural and agrarian economic base. In the Loveland Area, industrial loads of the public utilities appear to dominate the mix. In the Phoenix Area, the industrial load of the public utilities also dominates, reflecting souther California's dominant industrial base. Sacramento's load mix also reflects the area's dominant share of agricultural pumping load. High-load-factor industrial customers are also seen to be a prominent portion of load in the Salt Lake City Area Office.

3.7.4 Existing Demand-Side Management Measures

This section provides an overview of the existing DSM programs established by Western customers. Participation in the C&RE program was mandatory for all Western customers with firm-power contracts.

Under the previous requirement, Western required long-term firm electric service customers to develop and implement an ongoing conservation and renewable energy program, including a specified minimum number of annual activities. Based on the latest analysis of customer C&RE data, Western's customers are engage in 2,538 approved DSM or DSM-associated activities annually to comply with the minimum requirements for the G&AC. Based on customer-reported activities

Table 3.16 contains the wholesale rates that Western charges its preference customers for firm power and energy. While Western recovers its costs with a demand charge and an energy charge, the values reported include a composite rate, on an annual basis. For each area, rates are tied to the cost, recovery of the multi-purpose Federal projects, with the power generation function and other appropriate project costs assigned for repayment from power rates. The reported firm rate for the Phoenix Area is based on a simple average of the actual rates for its two dominant projects, using generated energy from each. The remaining areas develop rates for a composite of the Federal power plants rather than individually. Western also provides other services with separate rate schedules. For instance, costs of transmission service are recovered in its firm transmission and nonfirm transmission rate schedules. All rate schedules for long-term firm sales (power and transmission) are under the regulatory oversight of the Federal Energy Regulatory Commission (FERC).
tomer-reported activities over and above the minimum requirement, and the experience of Western personnel through customer visits, Western estimates that its customers have exceeded the mini
mum
requirements significantly, at least tripling the minimum requirements. The top categories of activities and associated numbers are load management devices and systems (268); energy audits

(228); upgradng tranSusasion lines and substations (189); infrd system scanning (154); lighting conversions (118); lighting redesigns and management (100); power factor corrections (97); and demand controls techniques and equipment (89).

Western's Energy Services Division assists customers in establishing DSM measures through a variety of measures. Since 1984, there have been approxunately 3,000 C&RE plsns reviewed, 150 costshared contracts, 320 workshops, 50 peer matches, 1,000 hotline calls, 150 technical assistance projects, and 2,500 irrigation pump tests. Each activity is in support of customer activities that further DSM.

3.7.5 Power Rates in Western's Region

This section provides an overview of current electricity rates across the 15-state area in which Western markets Federal power. The rates Western charges its customers are also presented in this context. Table 3.15 gives an abridged look at rates by customer class for the two broad utility organizations that sell retail electric energy across each of Western's marketing areas.

The "rates" are given in terms of unit or average revenues by class of customer: residential, commercial, and indusrriai. Rate schedules in reality are rarely of the umform nature that seem to be suggested here. That is, electric utility costs are conventionally recovered under tariffs or rate schedules with multiple parts. For residential users, rate schedules are usually characterized by a kilowatthour charge on metered usage (recovering both capital and certain variable costs) and a monthly service charge (recovering customer-related costs). In many instances, the kilowarthour portion of a residential electric bill may vary depending on the level of usage (either inverted block or declining block rates). Customers such as commercial and industrial users, on the other hand, are served under considerably more complicated rate schedules. Conventionally, these users are also metered for their demand for capacity in addition to the amount of energy they take, as well as monthly service costs associated with their accounts. Both the demand and energy portions for this type of customer can also be charged according to different blocks or levels of demand and usage.

Many retail utilities also have seasonal variants of these rate structures, with separate rate levels for different seasons of the year (usually winter and summer) or rate designs that differentiate capacity demand and energy use diurnally (time-of-use or time-of-day rate designs). Western's customers may choose to implement such rate strategies in the future as a result of their IRP analyses.

The actual comiguration of a utility's rate schedules is often based on regulatory rate-setting deliberations and an understanding of how the utility's costs are incurred. Strict cost recovery considerations are balanced with elements of equity, tariff understandability, administrative feasibility, and rate stability in finally establishing rate schedules.

Table 3.15 reports the rates charged retail customers of investor-owned and public utilities across the 15-state Western system, grouped by each of Western's marketing areas. Billings Area retail customers generally seem to benefit from the lowest rates, while Sacramento Area's retail customers pay the highest. These are composites across a broad range of retail utilities. Actual inter-system comparisons could produce differentials that differ from those suggested in the table. Industrial rates, and, to a lesser extent, commercial rates are less per kilowatthour than rates to residential customers, largely because industrial customers take service at higher voltage levels, thus obviating the need for the utility to put in place additional transmission and distribution facilities to serve the load.

Figure 3.21. Regional Customer Class Energy Use by Western Area Office

Table 3.12. Regional Energy Consumption by Customer Class (calendar year 1990)

Figure 3.22. Investor-Owned Utilities' Customer Class Energy Use by Area Office

Table 3.13. Buildings Inventory Summary^a

Table 3.14. Irrigated Acreage in Western's Service Region

Figure 3.23. Public Utilities' Customer Class Energy Use by Western Area Office

CHAPTER 4 Environmental Consequences

4.0 ENVIRONMENTAL CONSEQUENCES

This chapter describes the environmental impacts of all the alternatives. The environmental baseline from which impacts were predicted was the anticipated future condition that would exist through the end of the year 2015 if none of Western's proposed alternatives were implemented. Because the environmental baseline occurs as a period of time, and not a point in time, assumptions and predictions of future changes must be made to provide a reasonable projection of future conditions. The important point to be made here is that the No-Action Alternative, which is based on this anticipated future environment, does not mean an unchanged environment. A description of the environment as it exists today is presented in Chapter 3 (Affected Environment). Predictions of future trends, shown for each environmental resource, for the No-Action Alternative and other alternatives are described in this chapter.

In order to assess impacts to the environment, it was necessary to track both changes in baseline conditions over time, and the influence of Western's Program over time. Various assumptions and predictions, discussed later in this chapter, were made for all of the alternatives including the No-Action Alternative. Because of the complexity involved in evaluating these factors, a model was used to assist in predicting the future situation while incorporating all of the identified variables. Table 4.1 summarizes the environmental impact factors that were used to calculate environmental effects. Tables 4.2 and 4.3 summarize potential environmental impacts of the No-Action and Program Alternatives by impact category for the years 2005 and 2015.

Table 4.1 summarizes environmental and planning information for the generation portion of the fuel cycle. The information is generic in nature; it does not apply to any particular plant, but rather represents a range of plants or calculated values. Calculations and choices of environmental factors used to derive the information in Table 4.1 are described in Appendix F. These choices were made from a variety of sources to best represent the power plants in Western's service region. Sources of information include the following: Bradley, Watts, and Williams (1991); Chernick and Caverhill (1989); Fluor Daniel, Inc. (1988, 1991); Gleick, Morris, and Norman (1989); Kinsey (1992); NWPPC (1991); Ottinger et al. (1990); Public Service Commission of Nevada (1991); Shankle et al. (1992); State of California Energy Commission (1992); DOE (1983); and EPA (1985). The environmental impact factors used in the calculation of impacts were based solely on Table 4.1. The resources included in the model for potential growth in generation capacity over the next 20 years were coal-fired power plants, gas-fired simple-cycle combustion turbines, gas-fired combined-cycle combustion turbines, small hydroelectric plants, and combined renewables including wind and geothermal technologies. Coal resources were modeled as a combination of the three technologies (pulverized coal, fluidized bed coal, and integrated gasification combined-cycle) presented in Table 4.1. Some resources that were not modeled were included in Table 4.1 to allow for comparisons; these included diesel, wood waste biomass, municipal solid waste, wind, and cogeneration.

For some resources, Table 4.1 contains blank spaces for most environmental factors. For example, hydroelectric power does not emit significant ambient pollutants once installed. Resources with blank spaces may still produce impacts, but their impacts may be difficult to quantify generically. Descriptions of the demand-side and supply-side energy resources and any associated environmental impacts are provided in Appendix E. The effects of various types of air pollutants are described in greater detail in Appendix A.

Table 4.1 Planning and Environmental Profiles for Energy Resources

Table 4.1 Planning and Environmental Profiles for Energy Resources, continued

Table 4.1 Planning and Environmental Profiles for Energy Resources, continued

Table 4.2 Summary of Physical Environmental and Direct Employement Impacts Associated With Each Alternative in 2005

Table 4.3 Summary of Physical Environmental and Direct Employment Impacts Associated With Each Alternative in 2015

The balance of this chapter discusses the utility system model in more detail, and the impacts to environmental and economic resources. Results from the electric utility system modeling in Western's service region showed relatively slight differences among the Program Alternatives in terms of megawatts of installed capacity. However, the No-Action Alternative was found to have greater generation in order to serve larger loads. Along with the relatively slight differences in capacity additions, these differences in generation resulted in the environmental impacts summarized in Tables 4.2 and 4.3. As with changes in generation and capacity additions, only relatively minor differences were found across the alternatives in terms of environmental effects. Generally, those Program Alternatives featuring a more certain commitment of Western's power resources had relatively greater environmental benefits for certain emissions.

Another factor was the model input assumptions that were made for the alternatives.

The model estimated the aggregate effects produced by the anticipated customer response, but specific customer activities in response to the Program would still need to be estimated. These activities could have impacts in the future, and would be addressed once specific actions are identified. The No-Action Alternative resulted in differing impacts primarily because all Program Alternatives promote DSM and energy efficiency to a higher degree than would occur in the absence of the Program.

The analysis yielded impacts that were generic in nature, rather than impacts that were site specific. For example, the quantity of air emissions that may be emitted under each of the alternatives was estimated. However, the dispersion of pollutants, atmospheric reactions, and impacts on specific receptor populations can only be assessed on a case-by-case basis. As another example, the acres required to build new generating facilities were estimated, but specific impacts to land uses could not be predicted.

The analysis accounted for impacts resulting from the generation of electricity and the construction of new power plants, rather than other portions of the fuel cycle, such as mining and processing coal, transporting natural gas, or disposing of nuclear wastes. Expanding the analysis to include these other portions of the fuel cycle would add little to comparing the effects of the alternatives, as impacts from these activities would be largely dependent on specific choices and the location of generation. To the extent that the Program Alternatives would result in reduced loads and the use of fewer supply-side resources (these are the key variables affecting the outcome of the impacts presented in this EIS), the resulting impacts in other portions of the fuel cycle would follow similar trends to those presented here.

As specific activities or power plants are chosen, additional environmental analysis may be necessary. Western would complete this analysis for the resources that the agency initiates. However, it is unlikely that Western would initiate such projects. Most, if not all, of the activities would be proposed and implemented by individual utilities, utility-based associations, or other developers. For these non-Federal projects, environmental analysis and documentation would come in the form of siting, discharge, and use permits issued by local, State, and Federal agencies. Federal permits may require NEPA documentation, which would be determined by the issuing agency.

This environmental analysis involved the straightforward approach of multiplying an environmental factor by either the generation or capacity associated with each energy resource. The environmental impact factors and other planning information are listed in Table 4.1. The capacity and generation projections were modeled for each of Western's area offices. The modeling approach is described in Section 4.2. Section 3.7 in Chapter 3 describes loads and resources used as inputs to the model.

4.1 IMPACT TRENDS

A number of general trends were apparent from the analysis. First, the Program Alternatives tended to result in beneficial impacts in comparison to the No-Action Alternative. This trend was true for all of the physical environmental impacts analyzed and most of the economic impacts, and could be attributed to increased customer investment in demand-side resources instead of power plant construction. One exception was short-term rate impacts, which rose slightly to pay for planning activities (see Section 4.10). However, in the long term, rates tended to be reduced as utilities use resources more efficiently. Two analytical techniques were used to assess regional employment and effects on trade and commerce. Taken together, these analyses showed neutral to positive effects resulting from the Program Alternatives (see Section 4.9).

Another trend was identifiable in the relationship between environmental benefits and the certainty of Western's power commitments. For most environmental impacts identified in the analysis, an increase in environmental benefits was predicted in 2015 when assured, relatively high percentages of Western resources were extended. The Non-Extension Alternatives were consistently less beneficial to the environment than other Program Alternatives across all impact categories. The Limited Extension Alternatives and the Extension Alternatives, which featured an assured, high-percentage extension of existing resources, showed a similar pattern. This trend was attributed to relatively higher levels of plant construction and electricity generation by existing customers in reaction to uncertainty in Western's commitments. The size of the resource pool contributed to uncertainty levels because of the corresponding reductions in available Western resources. However, the manner in which the resource pool was used did not influence the analysis.

A third trend was true of all of the alternatives and was seen in the quantities of impacts over time. Impacts that were tied to coal combustion, such as SOx emissions and ash production, tended to peak in the year 2005, then decline. This trend mirrored the quantity of electricity generated from coal plants. Between 1995 and 2005 generation from coal plants tended to increase as these plants were used to meet increasing loads in areas that currently have surpluses of generation capacity. After 2005, the use of coal plants tended to decline as the plants aged and were replaced with less capital-intensive new technologies, such as combined-cycle combustion turbines (see Section 4.3.1.2). With all alternatives, impacts that tended to result from all thermal power plants, such as thermal discharge and CO_2 emissions, showed a steady increase over time, although the Program Alternatives were estimated to result in fewer impacts than the No-Action Alternative.

Electricity generation from coal plants was also related to a fourth trend. Coal combustion, and its related effects, tended to remain relatively unchanged across the Program Alternatives. Effects that resulted from both natural gas and coal (for example, thermal discharge, water consumption, and CO_2 emissions) tended to vary more by alternative as natural gas was used to a differing extent in response to uncertainty resulting from Western contract allocations. When comparing the impacts from total regional generation, these differences were usually quite small, less than 1 percent. However, when comparing the differences between the alternatives, the change varied from 2 percent to 23 percent.

A final trend was found in the distinction between physical impacts which resulted from generation and those which resulted from the construction of new capacity. Land use is the physical impact related to new capacity. The differences among each alternative's land use effects tended to be slightly magnified in comparison to the effects resulting from generation. This is due to the focus on only new development, without the influence of existing generation plants. Existing plants, which because of their greater numbers tended to dominate the effects of new plants, had a much greater influence on the effects resulting from electricity generation.

The impact estimates were built up from a model of utility systems in each of the area offices. The environmental impact results are reported in this document for the entire Western service region, although impacts on power resource needs are broken out by area office. This approach emphasizes the trends identified in comparing how the alternatives affect the environment. In an EIS of this complexity, these trends are more important than the actual estimated numbers. Further, the model identified the types of resources that may be built or implemented, but did not identify specific locations. Thus, a customer's need may be met by a plant built outside that customer's service area. This is more likely than in the past given the open transmission access provisions of the Energy Policy Act of 1992.

4.2 MODEL DESCRIPTION

This section provides an overview of the policy simulation model adapted for the analysis of the impacts from the Program on each of Western's areas.1 The baseline simulations of the No-Action Alternative and the results from the other alternative approaches are presented here.

The principal focus was on policy simulations to assess impacts on existing and new generation resources and on consumers' and businesses' electric energy service demands, which could be met with either conventional generation resources or with DSM resources (see Kavanaugh et al. 1993). While least-cost principles and rational decision making are presumed, the model was not intended as an IRP for Western's region. Each Western area was modeled and simulated under the alternative policy scenarios to determine probable impacts on power resources and on peak demands and consumption. A suitable framework for a regionwide IRP or set of regional IRPs would have to be broadened considerably beyond the policy simulation model advanced here.

Along with the description of the simulation model and the predicted Program simulation results, the discussion also focused on the macroeconomic assumptions that underlie the load forecasts and the assumptions that link the utility sector with this macroeconomic setting (see Section 4.2.2).

4.2.1 The Resources and Rates Impact Model

This EIS has adapted the logic and expanded computer code of an existing model used for regional policy simulation analysis of policies of a nature very similar to that contained in Western's Program. The model, the Conservation Policy Analysis Model (CPAM), was developed for the Bonneville Power Administration (Ford and Geinzer 1986) to examine resource and rate impacts of alternative conservation programs at an aggregate level for the Pacific Northwest. New versions of CPAM continue to evolve and are actively maintained for planning analyses at Bonneville. A similar model, albeit far more comprehensive from both an energy and geographical standpoint, served as the basis for the integrating framework for the 1991 National Energy Strategy (EIA 1991). The model, FOSSIL2/IDEAS was a long-run, dynamic policy simulation model of U.S. energy supply and demand and served as the basis for much of the representation of conservation resources for CPAM and the model developed here (AES 1990). (See Kavanaugh et al. 1993 for more information on macro-economic forecasting models of the U.S. economy.)

The general structure of the model used for the Western region impact analyses is illustrated in Figure 4.1. The model, referred to as the Resources and Rates Impact Model (RRIM), was written in DYNAMO, a high-level computer language specifically designed for system dynamics featuring feedback-loop effects.

The model consists of five sectors that represented different aspects of an electric utility system, or, as in the case here, a composite of like utility systems. The most detailed of the sectors is the electricity demand sector, which uses an end-use modeling approach to forecast electricity demand and conservation. This sector keeps track of the growth in the demand of energy services and electricity based on the growth in the region's economy, changes in the price of electricity, and the combination of user-specified conservation programs to be tested with the model.

The demand sector simulates the decision-making processes of retail customers as they react to electricity prices, appliance prices, subsidy programs, performance standards, and prices of competing fuels and appliances. Four basic customer groups are represented: residential, commercial, industrial, and irrigated agriculture. Residential customers include single- and multiple-family dwellings. Commercial customers include restaurants, office buildings, stores, hospitals, and smaller industrial loads (<1 MW). Residential and commercial buildings are divided into two types: old buildings and new buildings. Industrial customers are generally commercial entities that use more than 1 MW of

electricity.
The most important determinants of electricity demand are the growth rates for residential housing, commercial floor space, industrial activity, and irrigated acreage/cropland (see Tables 3.13 and 3.14). The growth in these "stock" variables directly determined the demand for energy services in the different end uses. Residential and commercial demand is divided into 10 "end uses." An end use is a service that is provided by energy, such as space heating, water heating, lighting, or refrigeration.

Figure 4.1 Resources and Rates Impacts Model (RRIM)

A fundamental assumption implicit in the structure of this sector is that consumers select the most cost-effective combination of fuel, appliance type, and efficiency in order to satisfy their need for energy services. Electricity is always the fuel of choice for those end uses captive to electricity, such as machine drives and lighting, but its market share in noncaptive end uses depends upon the degree to which electricity is the more cost-effective option compared to other fuels. The amount of conservation that is selected as a result subtracted from service demand to get net electricity demand.
Through the use of conservation programs, utilities could affect many aspects of consumer choice. For example, if a utility runs a subsidy program in a certain end use, it reduces the cost of higher efficiency technologies and thereby increase the cost-effectiveness level for electricity. Consumers who choose electricity end up selecting higher efficiency technologies, which, in fact, is a goal of the program. As a side effect, however, the program can end up reducing the cost of electricity-based services in general for that end use, which increases the market share for electricity. A conservation subsidy program also reduces the operating costs for existing electricity users in that end use, which allows these consumers to increase their comfort levels. Both of these actions, increasing market shares and increasing comfort levels, tend to offset the reductions in electricity use that are simulated by the program.
The primary function of the demand sector is to accurately account for electricity demand, conservation investments, and all the secondary effects that influence them. The resulting electricity demand is sent to the rest of the model, which calculates construction of new power plants, dispatches existing and new plants, and derives new electricity prices that were passed back through the demand sectors. This latter feedback loop permits sensitivity to price to affect the demand for electricity in case electricity price changes dramatically.
The system supply sector is responsible for supplying electricity to meet the needs of the electricity demand sector. It dispatches existing generation facilities, computes short-term power purchases or sales, adds new resources to meet load/resource deficits and calculates the operating and capital costs that are used for rate-making purposes in the price or rate module. The primary user-specified inputs to this sector are the capacity and costs of existing generation facilities and the timing, capacity, and costs of new generation facilities. The capacity expansion options spans five generic options for new utility generation: coal-fired power plants; gas-fired combined-cycle combustion turbine plants; gas-fired simple-cycle combustion turbine plants; hydroelectric plants; and other renewables using wind and geothermal technologies.
The price module of the RRIM contains a simplified algorithm that mimics the rate-making process. The model differentiates between investor-owned and public utilities in terms of their capitalization structure and tax status. The rate-making process is an accounting function that calculates allowed expenses (costs) and allowed income (return on rate base) in the case of investor-owned utilities. The price regulation sector used inputs from the supply, demand, and financial accounting sectors to determine a revenue requirement for the composite utility types.

4.2.2 Macroeconomic Assumptions

It is generally recognized that energy consumption is strongly tied to economic conditions. Forecasts of key economic variables that underlie the simulations had a significant part in the impact analyses, though they were held invariant across the alternatives. Forecasts of inflation rates, real gross domestic product (GDP), and population growth rates for the United States came from long-term economic forecasts developed by the Energy Information Administration (EIA) in the 1991 National Energy Strategy (EIA 1991). As briefly summarized in Table 4.4, real economic growth was assumed to occur at a diminishing rate over the planning horizon, partly due to the declining rate of population growth. Expected inflation was stable over the period, staying at roughly 5 percent per year over a majority of the simulation period. As for all economic forecasts, these expectations had a level of uncertainty associated with them. The values used typically fell in the midpoint of ranges that bound this uncertainty. Sensitivity analyses are presented in Kavanaugh et al. (1993), which focus on impacts due to departures from these mid-point expectations.
The assumptions regarding fuel prices also played an extremely prominent role in the simulations, from several standpoints. First, relative prices between natural gas and electricity affect fuel choice decisions in the demand sector. Second, relative fuel prices can greatly influence the economics of alternative supply technologies, and thus the composition of the generation used to meet loads placed on the systems. Current or initial fuel prices came from the EIA's Electric Power Monthly (EIA 1992b), stated in 1990 dollars for the year 1990. Table 4.5 reflects the variation across the broad regions encompassed by the Western area offices. The first row reports price per million Btus (mmBtu) on a delivered, weighted basis by major utility, for coal and natural gas in 1990

dollars. The next row reports the expected rate of escalation over general inflation ("real escalation") for each fuel over the simulation period from 1990 to 2030.

4.2.3 Major Issues for the Utility Impact Analysis

A number of issues emerged from the utility impact analysis that warrant follow-up analysis to indicate how robust the results were to possible changes in the baseline assumptions. Many of these were familiar from traditional long-term energy planning and some emerged from structural changes slowly occurring in U.S. energy markets. Finally, some have surfaced that were uniquely associated with the Western resource.

A brief list of the leading issues is given below. An evaluation of their impacts was a two-step process. The first was an initial examination to see if the results were sensitive to departures from the baseline assumptions. The second was to determine the impact of alternative assumptions, or treatment for those factors, that were found to exert the greatest or most significant influence on the simulation outcomes. Among the advantages of the RRIM framework was that it was extremely well-suited to the task of implementing this sensitivity process. Results of the sensitivity analyses are discussed in Kavanaugh et al. 1993. The range of probable issues included the following:

* uncertainty over future loads, including economic conditions
* uncertainty over fuel costs
* uncertainty over availability of natural gas
* uncertainties over DSM measures and conservation resources.

Table 4.4 Key Macroeconomic Factors

Year	GDP	Population	Inflation
1990-2000	3.0%	0.7%	4.52%
2000-2010	2.7%	0.5%	5.15%
2010-2020	1.9%	0.4%	5.0%
2020-2030	1.6%	0.2%	5.0%

Table 4.5 Fuel Price Assumptions by Western Area for Delivered Price to Utility ($/mmBtu)

Area:	Billings		Loveland		Phoenix		Sacramento		Salt Lake City	
Year	Coal Price	Gas Price	Coal Price	Gas Price	Coal Price	Gas Price	Coal Price	Gas Price	Coal Price	Gas Price
1990	0.44	1.37	0.70	1.33	0.74	2.22	1.13	2.20	0.93	1.41
Real Escalation Rate (%)	1.00	3.00	1.00	3.00	1.00	3.00	1.00	3.00	1.00	3.00

Source: EIA 1992b

A final source of uncertainty emanated from the Western wholesale power contracts. Uncertainty like this is normally not prominent in most utility resource planning activities; nevertheless, it can be addressed within a sensitivity framework along the lines of the foregoing elements. However, contract provisions that heighten or ameliorate planning uncertainties were at the heart of assessing impacts from Western's Energy Planning and Management Program. For a consistent evaluation of all alternatives, therefore, this source of uncertainty merited special recognition in this part of the analysis.

The current version of RRIM is essentially deterministic; that is, Western has used a specific set of assumptions rather than random values as model variables. RRIM is capable of handling probabilistic simulations which use a vast number of random variables to predict an outcome. However, the model has provided consistent results across sensitivity analyses. The introduction of random variables would provide little additional benefit for purposes of this EIS.

To place the No-Action Alternative on a comparable basis with the Program Alternatives (which possess important implications for the degree of certainty that Western's customers would be able to plan on), RRIM inputs were augmented with an adjustment that attempted to mimic the effects from uncertain contract terms that might

influence the amount of assured Western resources that a planner could depend on.
Fuller detail of this adjustment is contained in supporting documentation to this EIS (see Kavanaugh et al. [1993], Chapter 9.0). Essentially, the procedure used the "planner's" discount rate (adjusted for expected inflation) to proxy the resource cost of having a unit of assured capacity today versus a unit at some time in the future with less assurance. This "cost" was mimicked by adjusting contract capacity to a lower, "effective" capacity available for resource planning with the use of the real discount rate. The adjusted capacity was constructed using

Adj MW = MW [1/(1+r)n]

where r represented the real discount rate, n was the number of years spanning the time from the year a contract was expected to expire to the end of the simulation period, Adj MW was the adjusted capacity, and MW was the Western capacity under contract.
Since Project contract expiration dates and contract terms vary somewhat across Western's system, the effects of contract uncertainty should be expected to be similarly non-uniform. In the No-Action case, existing contract terms were presumed to stay in force at contract renewals. Some uncertainty emerged, however, in those areas possessing comparatively shorter contract lengths. For these, a subsequent contract renewal occurred before the end-year of the RRIM simulations. In these cases, it was reasonable to factor in planning uncertainty in the No-Action Alternative.

4.3 RESOURCES AND RATES MODELING RESULTS

This section discusses use of RRIM to model the No-Action and Program Alternatives. Although RRIM does have the capability to develop rates by revenue class, these highly aggregate system-level impacts are sufficient for the purposes here. Cost allocations and rate design do offer the potential for tempering any extreme effects on any one customer group; however, rate design is a separate process that is considered to be outside the scope of this EIS.

4.3.1 Resources and Rates Modeling Results- No-Action

The results from using the RRIM policy simulation model for the five areas in Western's region are presented here. Forecasts of peak load and electricity consumption are presented under the baseline economic conditions of the No-Action Alternative. The results for the No-Action Alternative are also featured with two major, but interrelated, sets of results from the RRIM output. First, the resources are portrayed over time to show the combination of existing generation resources and new resource additions. These displays are sometimes referred to as resource stacks. Conservation resources are shown on these resource stacks, as well. Second, the implications for the paths of retail rates and Western's rates under this baseline scenario are provided.

4.3.1.1 Load Growth and Energy Sales Forecasts

To best represent the demand and supply interactions associated with the Program, each region's loads (and ultimately resources) were built up by type of utility organization: investor-owned utilities, nongenerating public utilities, and generating public utilities. This enabled the model to preserve the salient features such as capitalization, tax status, and revenue requirements that differentiated the various types of systems which each have their exclusive area franchises and obligations to serve retail loads. Table 4.6 provides the breakdown of the load data summarized in Chapter 3 (Section 3.7.3) by these broad utility types for each of the Western area offices. Figures 4.2 and 4.3 present a comparison of how peak loads and energy were distributed across the regions by utility sector. Figure 4.4 plots the composition of loads of investor-owned systems only, for each Western area. Figure 4.5 reports the same for the publicly-owned systems, by area.

Table 4.6 Firm Energy Sales and On-Peak Load by Utility Group

Figure 4.2 Western Area Office On-Peak Loads by Utility Type

Figure 4.3 Western Area Office Energy Use by Utility Type

Figure 4.4 Investor-Owned Utilities' Customer Class Energy Use by Western Area Office

Figure 4.5 Public Utilities' Customer Class Energy Use by Western Area Office

Table 4.7 Load Forecasts, 1990-2015

The load and energy forecasts were developed from national economic assumptions, building stock assumptions, fuel prices, and electricity price feedbacks for each region. Table 4.7 contains, by area office, annual growth rates in the expected peak demand and net electricity consumed over the planning period, 1990 to 2015. The model assumed that public utility load growth was met first with generating public utilities and then investor-owned utilities, not by Western's resources, not even on a partial or limited basis on behalf of its preference customers.

The load growth and energy sales forecasts from the model suggested growth rates that were low by post-World War II experience. However, a comparison with the 1992 outlook provided by the North American Electric Reliability Council (NERC 1992) offered a favorable benchmark, although only a partial and imperfect one. While the NERC outlook revealed slightly stronger growth in regions that match up partially with Western's area offices, there were similar patterns. The model forecasted the strongest growth in the Phoenix and Sacramento areas, and this matched well with the Western States Coordinating Council subregions of Arizona-New Mexico and California-southern Nevada. Slower growth was expected in the Mid-Continent Area Power Pool (U.S. portion), which shared much of the same geography as the Billings Area and a small portion of Loveland. Some portions of the northern subregion of the Southwest Power Pool and the Rocky Mountain subregion of Western Systems Coordinating Council also had load in common with that of the Loveland Area.

Reasonable differences between the two sets of outlooks were accounted for by a number of elements. First, the boundaries of Western's areas differed from those of the regional councils/power pools of NERC, so any direct comparison was at best only approximate. Second, the NERC reports were from a "sum of the utilities" forecast, whereas RRIM built up loads on an aggregate basis by broad utility type. Third, the NERC forecast period was considerably shorter, spanning only 10 years, in contrast with RRIM's forecast horizon of 30 years, which permitted long-term demographics to have greater influence. Finally, the conservation module in RRIM was a prominent part of its policy impact focus, so conservation resources (which served to lower net loads) may have played a more significant role in meeting energy service demands than that assumed at some of the individual utility systems in these NERC regions.

4.3.1.2 Resources

For each area, Figures 4.6 through 4.10 show the generation mix changes over the 25-year period, as well as total on-peak demands. Forecasted peak demands were driven by assumptions governing business activity, demographics in each area, and region-specificfuel cost assumptions. These were tied to uniform assumptions at the national level, but as the load forecast table (Table 4.7) revealed, there was room for disparities to reflect specific characteristics of each area. The initial configuration of supply-side resources emanated from the Western resource database summarized in Table 3.10 of Chapter 3. However, the data in the figures (Figures 4.6 through 4.10) are for nameplate MW of capacity for peak demand. The data are net of imports and exports on an interregional basis.

Some further differentiation between the description of resources from the Western database in Chapter 3 is necessary to lay the foundation for discussing the results from the RRIM simulations. The Western resources database identified all generation resources by location. This is useful for geographical purposes but, for long-term resource planning, some modification was required to reflect that some resources were located outside a utility's immediate service territory for its native loads. For simulating the resource paths of the five areas, Western resources were "reassigned" according to firm commitments to serve loads outside the area in which they were sited.

This affected, for example, the Federal power output from the Salt Lake City Area Office. In Chapter 3, this resource, because of its location, was counted entirely as plant capacity within the Salt Lake City Area. However, for purposes of modeling the No-Action and Program Alternatives, portions of the SLCA/IP that were marketed in other areas were re-assigned to serve the preference customer loads in those particular marketing areas. This approach was also applied to some non-Western resources serving loads outside the region. For example, the Colstrip coal-fired units in southeastern Montana are jointly owned; that portion of the plant owned by Pacific Northwest utilities to serve their loads was netted out from the resource capability in the Billings Area that is available to serve private or public loads.

The Western resource database characterized a broad range of generation technologies and fuel types over Western's region. Such a detailed inventory of plant types necessitated some grouping to reduce the requisite data to a manageable level for policy simulation purposes. Plants that are oil-fired, have dual-fuel capability, or are fired with different grades of coal to generate steam were treated collectively as "fossil-steam" units and were included in the group of resources labeled as "old" or conventional coal.

Load growth and retirement of existing plants were the two factors influencing the capacity expansion plans of each region. Western recognizes that many of its customers have made significant investments in conservation in the past. The resource stack figures treat pre-1990 conservation as a reduction to load; the conservation shown after 1990 is incremental and in addition to historic conservation achievement.

Individual generating units were grouped into homogeneous classes, which formed the basis for projecting the long-run capacity expansion paths for the Western regions. Such aggregation facilitated the ready use of generic data from the EPRI Technical Assessment Guide (TAG) (EPRI 1989). One of the components of the cost and performance characteristics listed in the TAG is the unit life (in years) that is used by utility system planners in routine screening analyses. Because of the link between capacity/ plant expenses and financial/rates computations, the EPRI TAG planning assumptions were used for the book life of plants. These covered the following: coal-fired steam - 30 years; combined cycle combustion turbine plant - 30 years; combustion turbines - 20 years; and renewable (non-hydro) technologies - 20 years. For the physical life of the units, longer lives were assumed to reflect, in part, life-extensions and refurbishments, and the unit indivisibility elements of larger, baseload types of capacity. The following were used in this regard: coal-fired steam - 100 years; combined cycle combustion turbine plant - 50 years; combustion turbine - 50 years; and renewables - 75 years.

Overall, the recurring results from the RRIM simulations across all five areas indicated natural gas-fired units as the dominant technology for new generation additions. These encompassed combined-cycle combustion-turbine units, which could operate as baseload units, as well as combustion turbines for meeting peak demands of shorter duration. The selection of gas-fired over coal-fired technologies was based on comparative economics and inherited load/resource balances. Despite the higher expected escalation of natural gas prices over coal (3 percent versus 1 percent, see Table 4.5) the capital cost per kilowatt of installed combined-cycle combustion turbines was about half that of a large coal-fired plant. Where surplus baseload capacity was present, low-capital cost, gas-fired, combustion turbines were more economical than coal-fired units because they would operate for only short durations during maximum peak demand periods.

New nuclear power steam plant capacity was not added during the course of the simulations. Most, but not all, of this existing capacity (currently 8 percent system wide) was presumed to be relicensed. However, the model assumed that, until a permanent radioactive waste repository is established, no new nuclear capacity would be licensed and built in the United States. As a result, nuclear power's contribution to generation capability stayed unchanged, but with resource additions over time it declined in relative terms.

In the Billings Area (Figure 4.6), baseload coal-fired capacity appeared to be the dominant thermal resource (more than 80 percent), with nuclear steam-plant capacity the next largest (9 percent). Coal still remained the largest technology at the end of the simulation period in this analysis of the No-Action Alternative (48 percent by 2015 and 62 percent of all thermal capacity). However, there was a significant increase in combustion turbines in the mix, rising to nearly 3,700 MW. By 2015, combustion turbines represented almost 25 percent of thermal capacity in the area, and they were the primary new generation resource addition by that year. This was largely the outcome of load growth exhausting the capacity surplus that stemmed from the major building of coal plants in the late 1970s. Although capacity of combined-cycle combustion turbine plants grew in the mix in relative terms, the absolute growth of 900 MW was small compared with that of gas-fired combustion turbines.

The Loveland Area is roughly balanced under current conditions given net imports and short-term purchases (see Figure 4.7). With load growth and a fixed amount of firm imports, the area was anticipated to pursue an expansion plan comprised mostly of combustion turbines and combined-cycle combustion turbines. Coal units dropped from a dominant share of the generation resource stack currently to about 40 percent by the year 2015. Nearly 2,400 MW of gas-fired combined-cycle combustion turbines were added in the area, accounting for about one-seventh of all generation resources. Peaking capacity showed a major increase with the installation of gas-fired combustion turbines.

Figure 4.8 portrays the expansion path of the Phoenix Area's generation resources. Substantial inter-regional imports (e.g., into California from the Pacific Northwest and Desert Southwest) supplemented the area's indigenous capability to meet the current peak demand of approximately 41,000 MW. Under the No-Action Alternative, fossil-fuel fired capacity dropped from more than 60 percent of the generation capability to less than 33 percent by 2015. Gas-fired combined-cycle combustion turbines became the major new baseload resource, with nearly 12,000 MW added, and occupied a significant portion of the thermal resource mix at about 20 percent.

Figure 4.6 Billings Area On-Peak No-Action Resource Stack with Conservation

Figure 4.7 Loveland Area On-Peak No-Action Resource Stack with Conservation

Figure 4.8 Phoenix Area On-Peak No-Action Resources Stack with Conservation

Figure 4.9 Sacramento Area On-Peak No-Action Resource Stack with Conservation

Figure 4.10 Salt Lake City Area On-Peak No-Action Resource Stack with Conservation

The role of fossil-fuel-fired capacity was almost halved in Western's Sacramento Area over the simulation period in the No-Action Alternative, as well (see Figure 4.9). New combined-cycle combustion turbine capacity was the prominent baseload technology added to the resource stacks of utilities, with nearly 7,400 MW of capability, and accounted for nearly one-third of thermal resources by the year 2015. The remainder of new capacity was accounted for by combustion turbines: more than 6,400 MW by the end of the planning period.

Resources for the Salt Lake City Area Office are shown in Figure 4.10. In the Salt Lake region, fossil steam units accounted for an extremely large share of the current resource capability, at nearly 90 percent. New capacity additions did not occur until early in the next decade, given anticipated load growth and extra-regional transactions. Coal was still the dominant fuel for power plants in 2015 (about 48- percent) and peaking capacity units in the form of gas-fired combustion turbines accounted for the majority of new thermal capacity-more than 2,800 MW. Gas-fired combined-cycle combustion turbines were also a prominent resource addition in the thermal mix, making up nearly one-third of installed thermal capacity by 2015.

4.3.1.3 Conservation

If the electricity needs of consumers and businesses are to be met efficiently, utility conservation programs would warrant comparable treatment to conventional generation resources. DSM programs for utilities can encompass conservation as well as a wide variety of other approaches to more energy efficiency on the customer side of the meter. These can include, for example, interruptible rates to industrial customers, load management devices such as electric water heater cycling, and retail rate design such as time-of-use rates. Conservation investments by both consumers and utilities were at the center of the demand module of the RRIM framework developed for simulating baseline energy paths. DSM measures, or "technologies," were represented in the model as supply curves that related the amounts of capacity/energy saved as a function of measure costs, system avoided costs, and electricity rates. Supply curves existed in RRIM for each end use and fuel type in the residential and commercial sectors, as discussed above in Section 4.2.1 and as developed in fuller detail in Kavanaugh et al. (1993).

Figures 4.6 to 4.10 highlight the role of conservation resources in the No-Action simulations by area office. Under the No-Action Alternative conservation would occur in response to Western's G&AC, other applicable regulations, and independent decisions made by Western's customers. The figures show a consolidated generation resource stack and then add on-peak megawatt savings emanating from DSM under the No-Action Alternative. Capacity savings from DSM were implicit in current loads across the areas; that is, the energy service demands placed on the serving utilities reflected the net of demand after conservation. The tables in the lower portions of each figure show conservation in incremental terms above net demand. They are zero in the base year of the simulation. Conservation in excess of that currently embedded in the net energy sales to customers is the conservation resource shown there.

With the exception of the Phoenix and Sacramento areas, conservation was largely nonprogrammatic. That is, the conservation that occurred in the residential and commercial sectors was assumed to be price-induced. In the Billings, Loveland, and Salt Lake City areas, building energy efficiency programs were instituted up to a cost of 20 mills. In the Phoenix and Sacramento areas, the cost cap for comparable measures was established at 45 mills. Utility programs (typically with incentive or subsidy features) were instituted in the Phoenix and Sacramento areas up to a program cost level of 45 mills.

The relative shares that DSM was projected to represent in the resource stacks by area varied slightly, largely as the result of differences in a number of factors. These spanned differences in initial residential and commercial building stocks and new additions to them, each area's load/resource balance, and relative fuel prices. In Billings, DSM resources expanded to the point of accounting for nearly 6 percent of all resource capability (see Figure 4.6). Both the Phoenix Area (Figure 4.8) and Sacramento Area (Figure 4.9) displayed an even more pronounced role for DSM in meeting their respective energy service demands. More than one-eighth (13 percent) of the resource capability was DSM in Phoenix and nearly one-seventh (14 percent) was DSM in the Sacramento Area. In the Loveland Area (Figure 4.7), DSM resources amounted to about 10 percent of all resources by the year 2015. The Salt Lake City Area (Figure 4.10) reflected a similarly-sized role for DSM by the year 2015, amounting to 11.5 percent.

The financial implications from these load growth and regional expansion paths are summarized in Table 4.8. The table presents the approximate current rates by type of utility organization, along with the expected escalation over the simulation period of 1995 to 2015. The average revenues were current dollars, so the indicated escalation usually did not exceed the annual average inflation expected over the period, which was on the order of 5 percent. Thus, real system average costs were found to be essentially flat for a considerable number of the utility sectors. The exceptions to this were the non-generating publics in the Phoenix and Sacramento areas. Slightly higher escalation than average was also indicated for the investor-owned systems in the Phoenix and Sacramento areas, as well as for the groups of non-generating public utilities in the Salt Lake City area of the Western system.

4.3.2 Alternative Cases

This section describes how the model was used to simulate the impact of various Program initiatives. The balance of the section is divided into three parts. The first defines the different alternatives, the second describes how they influenced model behavior, and the third presents model results and describes the impacts on resources, loads, and rates.

4.3.2.1 Program Alternatives

A total of 12 alternatives were simulated with RRIM, 11 Program Alternatives and the No-Action Alternative. The Preferred Alternative is treated as a combination of Alternative 5 and 6. It was not actually modeled. No distinction was made in the model between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning. As a result, the following alternatives were analyzed with the RRIM model:

* No-Action
* 15-year term, 98 percent extension
* 25-year term, 95 percent extension
* 25-year term, 98 percent extension
* 35-year term, 90 percent extension
* Non-Extension
* Limited Extension.

The alternatives under consideration were designed to affect the fraction of the resource commitments extended by Western, the review period, the withdrawal provisions, and the utility planning process.

The Extension Alternatives looked at uniform modifications across several contract features, including contract length and percent of resource extensions. For modeling purposes, the fraction of the resource commitments extended was assumed to be 100 percent in the No-Action Alternative and 98, 95, or 90 percent in the Extension Alternatives. The utilities incorporated current resource commitment levels, along with the extension provisions, in their planning processes. Unallocated Western power was directed to a resource pool from which it was redistributed to other preference (public utility) customers. For modeling purposes, the power withdrawn for the resource pool was not a resource available to meet firm loads over the planning horizon. The model assumed that utilities must secure capacity to replace that portion withdrawn by Western.

The remaining alternatives fall outside the class of alternatives from the paragraph above. These are the Limited Extension Alternatives and the Non-Extension Alternatives. For modeling purposes, the Limited Extension Alternatives were characterized as having a 10-year, "automatic" extension of current contract provisions from the date of IRP approval in those areas where current contracts expired before 2006. Western assumed that for the time period beyond 2006, the terms of contract were the same as existing contracts. A 90 to 98 percent extension of the Western resource was assumed beyond 2006; for modeling purposes the draft EIS analyzed a 90 percent extension.

Table 4.8 Rates and Escalation under the No-Action Alternative

For the RRIM analysis, the Non-Extension Alternatives were basically a hybrid of the No-Action Alternative with an IRP requirement in 1995. Thus, formal IRP activities were presumed to commence with current contract provisions intact for each respective area. For modeling purposes, the draft EIS assumed a 100 percent extension for the same term as existing contracts.

For all classes of alternatives there was a common thread of uncertainty regarding the resource extension amounts at the time of contract renewals. In all cases, the RRIM inputs were adjusted for this probable effect in the same fashion as for the No-Action case and as discussed above in Section 4.2.3. A more complete discussion can be found in Kavanaugh et al. 1993, Chapter 10.

In response to the IRP provisions, generating and nongenerating utilities were assumed to develop programs that targeted all conservation measures below some threshold cost. The programs identified here represent one specific set of activities utilities could undertake. The purpose of describing them in this section is to provide an explanation of how the program was modeled. It is not intended to be exclusive or prescriptive. Due to regional generation surpluses in the Upper Midwest, the model assumed that programs in the Billings Area would be implemented starting in the year 2000. In other areas, the model assumed a 1995 start date.

In new buildings, utilities were predicted to provide 50 percent of the capital cost associated with conservation measures that cost up to a user-specified amount. The model assumed that all public utility customers were subject to energy-efficient building codes and that all could participate in utility-sponsored conservation programs. The utility programs covered only those measures above and beyond the building codes. For the purpose of this analysis, both deficit and surplus utilities were assumed to offer incentives, though the level of conservation purchased differed by region to reflect differences in the value of energy saved. All new residential and commercial structures were assumed to be built to the equivalent of an energy-efficient building code.

For existing buildings and industrial facilities, utilities were assumed to offer subsidies of 50 percent to those who voluntarily entered the program. Participation rates and limits were specified by end-use sector. For the Billings, Loveland, and Salt Lake City Areas, the conservation program costs were capped at 35 mills/kWh. The Sacramento and Phoenix areas faced a cap of 50 mills/kWh.

The ultimate number of customers eventually participating in the program, and the rate at which they sign up, was user-specified. The model assumed that 60 to 85 percent of eligible building owners participated and that most of them were on board after 10 years. Industrial conservation "rolled in" over several years as plant owners responded to changing energy prices or programs. The cost thresholds used for the residential sector also applied to industrial loads. However, here the model employed a different approach to estimating potential load reduction from conservation. Rather than accounting for specific processes, the model treated the industrial sector in the aggregate. The model assumed the entire sector moved from its existing average level of conservation activity to a target level of activity. This movement was spurred by normal investment criteria and was influenced by utility incentives and programs.

Most of the Program Alternatives were differentiated only by contract term and percentage extension of existing or current contracts. These cases were all simulated with RRIM. The inherent resource planning uncertainty posed by the various proposed contract terms (15, 25, and 35 years, to commence at current contract expiration) was incorporated in RRIM in exactly the same fashion as was done for the No-Action Alternative (discussed above in Section 4.2.3).

4.3.2.2 Responses to the Program Alternatives

The conservation programs and contract extensions influenced the model's behavior in several important ways. Conservation programs were predicted to cause a decrease in end-use demand by increasing the number of conservation measures purchased and installed. Utilities were forecasted to experience an immediate decrease in their operating expenses as production requirements fell. Rates may rise or fall depending on the utility cost of the conservation program and marginal operating costs. In the longer term, reduced loads lowered forecasted loads and influenced capacity expansion requirements.

Changes in the rates influence near-term consumption. As the consumers' annual cost for electric services changes relative to income, they may modify their behavior (e.g., by changing thermostat settings). Further, if electricity costs change relative to gas costs, the market share of electricity for new space heating and water heating applications would change.

The contract extension provisions were predicted to affect the utilities' capacity expansion forecasts. When a portion of the existing firm power from Western was no longer assumed to be available, the utilities were expected to plan to acquire replacement power. The model assumed that the generating public and investor-owned utilities would build new generating capacity and would tend to select the most economical technology available. The nongenerating public utilities would turn first to generating public utilities for power, then, as a second choice, to the investor-owned utilities. As new generating capacity was built, the utility was assumed to recover the expensed portion of the capital costs and increased debt service in its current rates.

The alternatives tested all had an impact on the overall demand for electricity. The changes expected due to the conservation programs dominated those caused by the contract extension provisions, as expected. Conservation investments were predicted to cause immediate efficiency gains. Contract extensions would have a much more subtle effect as their influence on demand would be limited to consumers' response to changing rates as an outgrowth of cost recovery under alternative capacity expansion plans. The analysis of expected rate impacts is presented in Section 4.10. The investor-owned utilities would experience a negligible change in demand since the IRP provisions would affect only Western preference customers.

Table 4.9 presents the estimates of electric energy consumption by area office under these various alternatives in the year 2015. The analysis of the 25- year/98-percent Alternative (Alternative 8) showed a reduction in energy usage of approximately 5 to 15 percent. The Phoenix and Sacramento areas were projected to experience less of a reduction (4.9 percent and 6.9 percent, respectively) than the other regions because a substantial amount of conservation activity already exists there and is embedded in the No-Action case. Billings, Loveland, and Salt Lake City were anticipated to experience larger savings from conservation resources.

Table 4.9 Retail Utility Energy Use in 2015 (Gwh)

Figure 4.11 displays the impacts of the 25-year/ 98-percent Alternative (Alternative 8) in terms of the amount of thermal resource additions that would be displaced in the year 2015. Although impacts on coal-fired capacity are provided in the figure, only combined-cycle combustion turbines and combustion turbine additions were affected. Relative to the No-Action Alternative, the customer response to this Program initiative would reduce the amount of generation resources in all the areas. The largest absolute impact occurred in the Phoenix Area, with over 700 MW less of combined-cycle combustion turbine capacity and over 500 MW less of combustion turbine capacity added by 2015. For the Billings area, the displacements are similarly large, but they are primarily manifested in displacement of low capital cost-peaking capacity. For the Sacramento, Loveland, and Salt Lake City areas, the thermal capacity additions displaced by this Program Alternative reflected a similar, although smaller, outcome. Combined-cycle plant capacity was lower by 298 MW to 313 MW, and installed combustion turbine capacity was lower by approximately 350 to 600 MW in each of these three areas. This shift was caused by the program's effect of lowering on-peak demand by a sufficient amount to make combined-cycle combustion turbines, which can operate efficiently off-peak, economically attractive. The total impacts under this alternative amounted to displacement of 2,920 MW of combustion turbine plant and 1,900 MW of combined-cycle plant across the Western system.

Figure 4.11 Difference in Capacity by 2015 between No-Action and 25-year/9

Figure 4.12 Difference in Capacity by 2015 between No-Action and Non-Extension Alternatives

Figure 4.13 Differences in Combined-Cycle Turbine Capacity by 2015 Between No-Action and Various Alternatives

Figure 4.14 Difference in Combustion Turbine Capacity by 2015 between No-Action and Various Alternatives

The Non-Extension Program Alternatives represent a case where IRPs were implemented by Western's customers, with no changes from existing contract provisions. Thus, they presented the best perspective among all the alternatives of the benefits from engaging in IRP system wide. Figure 4.12 shows the displaced thermal additions compared to the No-Action case. Qualitatively, the direction of the results was very similar to the 25-year/98 percent case. Overall, however, displaced capacity additions were smaller than for the foregoing comparison. Only 1,820 MW of combustion turbine and 1,470 MW of combined-cycle combustion turbine capacity were displaced, compared to the No-Action Alternative.

Long-term impacts on retail rates are presented below in Section 4.10. Figures 4.13 and 4.14 show the impacts on thermal resource additions for the remaining alternatives (Alternatives 2-7, 9 and 10). Because of their similarities, these alternatives were grouped to show displaced thermal capacity additions. Figure 4.13 shows the uniform impacts of displaced combined-cycle capacity. Figure 4.14 shows the uniform impacts of displaced peaking capacity under these cases. Construction of renewables, coal, and small hydroelectric resources would remain largely unaffected because low capital costs would make combustion turbines cost-effective.

4.4 AIR QUALITY IMPACTS

In this section, estimates of the air quality impacts expected from each alternative are provided. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning.

4.4.1 Ambient Air Quality

To assess ambient air quality, the total tons of expected emissions produced from electricity generation from all sources were estimated under each of the alternatives. These estimates were made for SO2, NOx, TSP, and CO2. These are emissions commonly associated with electricity generation.

The reactive pollutants that may form from power plant emissions could not be quantified. Reactive pollutants include atmospheric ozone and acid deposition. These pollutants are dependent on atmospheric chemistry and physics. Factors such as wind, sunshine, precipitation, local terrain, regional landscapes, and background pollutant levels are all important in the formation, dispersion, and effects of these pollutants. These factors are dependent on the specific locations of power plants, which could not be predicted for this analysis.

Estimated tons of emissions for Western's service region are presented in Figures 4.15 through 4.18. These estimates were calculated by multiplying the environmental impact factors presented in Table 4.1 (see air emissions, lb/MWh, CO2, SOx, NOx, and TSP) by estimated megawatt-hours of generation as predicted by RRIM for various types of power plants (see Tables 4.9 and E.2). See Appendix F for more information on the derivation of these environmental factors. Figures 4.15 through 4.18 show total emissions for each alternative in Part a and the differences between each Program Alternative and the No-Action Alternative in Part b.

The EIS analyses suggested that, in comparison with the No-Action Alternative, any of the Program Alternatives would result in fewer emissions to the atmosphere over time because of reduced generation from customer investment in conservation and DSM. When compared with total emissions from the entire utility industry in Western's service region, these reductions appeared to be small. However, in absolute terms, the reductions are important. For example, a typical 500-MW coal plant produces about 2,600 tons of SOx, 5,200 tons of NOx, 500 tons of TSP, and 3.2 million tons of CO2, annually. As shown in Figure 4.18, the Program Alternatives would reduce annual air emissions by about the equivalent of one to two coal plants in 2015. A similar comparison with natural gas-fired simple cycle combustion turbines results in offsetting about 11 to 14 250-MW units when SOx is ignored. These units produce little SOx in comparison with coal plants.

A comparison of the Program Alternatives with the No-Action Alternative gave the following ranges of estimated reductions in total annual emissions:

SOx - 1,960 to 2,910 tons in 2005 and 2,690 to 3,000 tons in 2015
NOx - 5,210 to 6,960 tons in 2005 and 7,690 to 9,370 tons in 2015
TSP - 450 to 600 tons in 2005 and 630 to 760 tons in 2015
CO2 - 4.8 to 6.6 million tons in 2005 and 8.6 to 11.3 million tons in 2015.

Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Table 4.10 illustrates the estimated air emissions reductions in 2015 resulting from Alternatives 5 and 6.

Emissions of SOx and TSP peaked in the year 2005. The remaining emissions, NOx and TSP, showed a slight increase between 2005 and 2015. The trend for SOx and TSP was parallel to that of the use of coal combustion for electricity production. Although loads were predicted to grow in all of the study years, coal use increased between 1995 and 2005, but decreased between 2005 and 2015.

Two primary forces contributed to this temporal pattern of coal usage and SOx/TSP emissions. First, there was an underlying trend of declining coal-fired capacity because of coal plant retirements. Coal was still predicted to be the dominant technology in the year 2015, but it was significantly less so than in 1990. Coupled with this trend was the somewhat cyclical pattern of coal-fired generation in three of Western's five areas. For

Billings, Loveland, and Phoenix, off-peak loads (a dominant portion of the hours of a year of plant operation) were low relative to installed baseload capacity. Must-run units, like nuclear, were augmented with coal units running at less than full load. Off-peak loads grew over time and with them the fuller use of coal plants. Coal plant output increased over the first half of the simulation period, peaked around 2005, and then declined for the balance of the simulation period, reflecting retirements and the comparatively small additions of new coal-fired units.

The coal-fired units tended to be supplanted by natural gas-fired combustion turbines. NOx and CO2 are emissions associated with both coal and natural gas-fired plants, thus, they did not show declines between 2005 and 2015. To the extent that the Program would reduce these emissions in comparison to the No-Action Alternative, it would produce beneficial, indirect impacts on vegetation, infrastructure, and human health. (See Appendix A for a general discussion of how air emissions impact the environment.)

Table 4.10 Air Emission Reduction from the No-Action Alternative in 2015

Emissions Type	Alternative 5	Alternative 6
SOX (tons)	3,000	2,950
NOX (tons)	9,370	9,110
TSP (tons)	760	740
COX (tons)	11,270,000	10,930,000

4.4.2 Indoor Air Quality

The key environmental impact associated with building envelope conservation measures is indoor air quality. Indoor air quality and ventilation are described in Section 3.2.2. For the most part, conservation measures do not introduce sources of indoor pollutants. Sources that are introduced tend to be short-lived. Conservation measures may impact indoor air quality when ventilation rates are changed. The quality of the indoor air is determined by sources of pollution. If indoor pollution sources are present, ventilation rates are an important factor in flushing out dirty air. If sources of pollution originate outdoors, reduced ventilation may improve the quality of indoor air. Because of the complex set of factors that interact to affect indoor air quality, both positive and negative impacts may result from conservation activities.

Without detailed information about the existing condition of buildings in Western's service region, the changes in ventilation rates expected to occur, the source strength of different indoor pollutants, and the exposed population, it was not possible to calculate impacts that may result from utility conservation programs. However, the experience of state and Federal agencies suggests that Western's customers could design conservation programs that avoid negative impacts on indoor air quality.

Environmental analyses of energy-efficient building standards in California concluded that these standards do not cause significant impacts on indoor air quality (CEC 1991a, CEC 1991b). These analyses found that building standards, specifically those based on standards set by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE 62-1989), were adequate to ensure that energy-efficiency measures would not degrade the quality of indoor air. An analysis by DOE (Hadley et al. 1989) found that indoor pollutant levels would not be increased beyond levels that would cause health effects in most individuals, even at the minimum allowable infiltration rate. An environmental impact statement by the Bonneville Power Administration (1988) found that mitigation techniques, including source control and ventilation, could control impacts resulting from conservation.

Figure 4.15 Regional SOX Emissions

Figure 4.16 Regional NOX Emissions

Figure 4.17 Regional TSP Emissions

Figure 4.18 Regional CO2 Emissions

4.5 WATER QUALITY AND CONSUMPTION IMPACTS

This section presents estimates of water consumption and waste water production from power plants developed under the No-Action and Program Alternatives. Section 3.3 presented a description of the water quality found in the 15 states in Western's service region. Indicators of water quality used by the states include compliance with Clean Water Act goals and estimates of specific resource losses, such as wetlands. The estimated impacts described in this section cannot match the level of detail provided in the Chapter 3 discussion. Although total water consumption and waste water produced was calculated, it was not possible to know what the sources or sinks for this water would be. This level of detail would require specific knowledge of the location, operations, and technologies of existing and future plants. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning.

4.5.1 Water Consumption

Estimated power plant water consumption is shown in Figure 4.19. Part a of this figure shows total water consumption of all alternatives; Part b shows how much each alternative differed from the No-Action Alternative in terms of water consumption. Clean water is a scarce resource in many western states. Water consumption is an important issue because power plants must compete with other needs for a limited resource. Most thermal power plants rely on surface water, although some existing plants do rely on groundwater. In areas that depend on groundwater as a source of water (see Table 3.6), a power plant would compete with other uses such as residential and agricultural needs.

The estimated acre-feet of power plant water consumption across Western's service region was calculated by multiplying the environmental impact factors (see water pollutants, consumption, acre-feet/MWh) presented in Table 4.1 by megawatt-hours of generation for various power plant types as estimated using RRIM. See Appendix F for more information on the derivation of these factors in Table 4.1. Generation is shown in Tables 4.9 and E.2. A comparison of the Program Alternatives with the No-Action Alternative shows a reduction in water consumption of about 4,100 to 6,180 acre-feet in 2005 and 10,210 to 13,560 acre-feet in 2015, as less construction of supply-side resources occurs due to customer pursuit of conservation and DSM. Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Table 4.11 illustrates the estimated waste water and consumption reductions in 2015 resulting from Alternatives 5 and 6. Actual impacts on local consumption patterns would depend on the specific locations and technologies. For comparison a typical 500-MW coal plant consumes about 4,000 acre-feet annually.

Table 4.11 Waste Water and Water Consumption Reductions from the No-Action Alternative in 2015

Impact Type	Alternative 5	Alternative 6
Water Consumption (acre-feet)	13,550	13,250
Waste Water (tons)	3,460,000	3,370,000

Figure 4.19 Regional Power Plant Water Consumption

Figure 4.20 Regional Power Plant Waste Water Production

4.5.2 Waste Water Production

Estimated waste water production from power plants is shown in Figure 4.20. This figure shows total waste water production for each alternative in Part a and illustrates how much each alternative differed from the No-Action Alternative in Part b. These estimates do not include factors for nuclear power, which has variable waste water production rates (DOE 1983). The estimates apply to Western's entire service area and were calculated by multiplying the environmental impact factors (see water pollutants, waste water, lb/MWh) presented in Table 4.1 by megawatt-hours of generation from various power plant types (see Tables 4.9 and E.2). A comparison of the Program Alternatives with the No-Action Alternative showed a reduction in waste water production from 1.39 to 1.93 million tons in 2005 and 2.64 to 3.47 million tons in 2015, as less construction of supply-side resources was expected to occur due to customer pursuit of conservation and DSM. For comparison, a typical 500-MW coal plant produces about 1.7 million tons of waste water per year. Different power plant types and potential environmental impacts are described in Appendix E.

Thermal waste water from electric power plants usually contains higher concentrations of dissolved solids than the plant's source water. A listing of typical constituents discharged by generation type is contained in Table F.2 of Appendix F. It was not possible to predict the specific impacts of these discharges without knowing their characteristics and locations. However, the discharges would have to meet Federal and State permit requirements for environmental protection.

Large thermal plants are likely to have water treatment facilities to mitigate most effluents. In some cases these treatment plants can provide habitat for some fish and waterfowl. However, treatment impoundments could also be too polluted for this purpose.

Most waste water is treated and released as surface water. However, technologies that require subsurface drilling can impact groundwater. Geothermal plants bring hot brines to the surface for power generation and reinject the brines back into the earth. These reinjected brines hold some potential for groundwater contamination, although they were not specifically listed as a source of contamination in any of the 15 states in Western's region.

Oil and gas exploration and processing were listed as a source of groundwater contamination in nine of the states and were considered an important source in four of these states (see Table 3.5). Oil and gas exploration and processing are important to electricity generation as a source of fuel for simple and combined-cycle combustion turbines, diesels, and other technologies. However, the analysis in this draft EIS focused on impacts resulting only from the actual generation of electricity. To the extent that reliance on supply-side resources would be reduced by the Program Alternatives, it follows that the Program Alternatives would tend to result in reduced impacts to groundwater from oil and gas processing.

Waste products from coal and nuclear generation plants could also contribute to groundwater contamination. Ash production estimates are presented in Section 4.7. Nuclear wastes were assumed not to be affected by the Program Alternatives.

4.6 THERMAL DISCHARGE

Thermal discharge may be released to either the air or water, depending on power plant design. In this section estimates of thermal discharges are shown for each group of the alternatives across Western's service region. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning. The estimates are presented in Figure 4.21. This figure shows total thermal discharges of each alternative in Part a and illustrates how much each alternative differed from the No-Action Alternative in Part b. The Program Alternatives reduced thermal discharge by 24.2 to 32.5 trillion Btus in 2005 and 52.3 to 70.4 trillion Btus in 2015 compared with the No-Action Alternative. Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Alternative 5 was estimated to reduce thermal discharges in 2015 by 70.4 trillion Btus. The estimate for Alternative 6 was 68.43 trillion Btus. For comparison, a typical 500-MW coal plant produces about 16 trillion Btus per year.

Figure 4.21 Regional Thermal Discharge

Figure 4.22 Regional Ash Production

These estimates were calculated by multiplying the appropriate environmental impact factor from Table 4.1 (thermal discharge in millions of Btus) by megawatt-hours of generation for different power plant types shown in Tables 4.9 and E.2. Reductions resulted because the expected level of supply-side development under the No-Action Alternative was reduced by increased conservation activities promoted by the Program Alternatives. Thermal discharges to water bodies could have direct impacts on aquatic biota. Examples of these impacts include temperature-induced mortality, reproductive failure, and higher energy requirements. Thermal discharges to the atmosphere commonly contain elevated water vapor concentrations, which can produce local fog and rime ice deposits.

4.7 SOLID WASTE

Solid waste products can vary substantially across generating technologies. For coal-burning technologies, combustion processes produce ash and material collected from air pollution control equipment. Nuclear plants produce spent radioactive fuel and other materials contaminated with radioactivity. Geothermal plants must contend with drilling mud and brine that may carry with them naturally occurring regulated substances. Plants such as combustion turbines, hydroelectric plants, wind generators, and solar facilities produce little solid waste other than routine office and maintenance materials.

The single largest component of solid waste produced from electricity generation is ash from the combustion of coal. Ash presents disposal (availability of landfill space) and contamination issues for surface and groundwater. The quantity of ash produced by the alternatives was calculated by multiplying the environmental factors (solid waste, lb/MWh) listed in Table 4.1 by the projected megawatt-hours of coal plant generation in Table E.2. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning.

Figure 4.22 shows estimates of the total ash produced by each alternative in Part a and how much each alternative differed from the No-Action Alternative in Part b. In comparison with the No-Action Alternative, the Program Alternatives reduced ash production by a projected 30,000 to 60,000 tons in 2005 and about 50,000 to 60,000 tons in 2015 (thus reducing leachate and landfill volume as well). Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Alternatives 5 and 6 were estimated to reduce ash from coal plants in 2015 by 60,000 tons. A typical 500-MW coal plant produces slightly less than about 50,000 tons per year.

4.8 LAND-USE IMPACTS

Land-use impacts from electricity generation were assumed to be due to the area of land needed to site particular power plants and related power transmission facilities and the congruity with which plant activities fit into existing land-use patterns. Potential issues could include congestion, traffic, noise, interference with radio and television communication, and acreage. Most of these impacts could not be quantified as part of this analysis as there was no way to accurately predict where new power plants would be sited. The acres of land required for each of the Program Alternatives were projected.

These estimates were made by multiplying the environmental impact factors presented in Table 4.1 (construction in acres per megawatt) by megawatts of new capacity for various types of power plants. New capacity for each year was summed between the study years. For example, new capacity summed for the years 1996 through 2005 was used to calculate the land-use impacts of the alternatives for the study year 2005. Estimates of impacts are shown in Figure 4.23. This figure shows total acres required by each alternative in Part a and how much each alternative differed from its No-Action Alternative in Part b. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act required the use of IRP principles by small customers for their future resource planning.

Figure 4.23 Regional Land Use Impacts

This comparison showed that the Program Alternatives resulted in an estimated 41 to 64 fewer acres of development between 1995 and 2005 and 103 to 187 fewer acres between 2006 and 2015. Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Alternatives 5 and 6 were estimated to reduce acres of land required to build new power plants by 180 acres and 175 acres in 2015, respectively. Additional acreage could be impacted by the construction of fuel conveyance facilities, transmission lines, or substations; the impact of this construction would be dependent on power plant location, which could not be predicted at this time. Land use could also be affected by noise, traffic patterns, and hazardous waste transport. These issues are discussed in Appendix E.

4.9 SOCIAL AND ECONOMIC EFFECTS

In this section estimates of the direct employment and regional economic effects resulting from the alternatives are presented. Section 4.9.1 lists direct employment impacts from building the initial facilities and from operation and maintenance activities. Section 4.9.2 is based on a more sophisticated modeling approach that estimated regional impacts. Taken together, these two approaches showed neutral to positive effects resulting from the Program Alternatives. Both techniques were employed to establish the range of economic effects that may result from the alternatives.

Direct employment, discussed in Section 4.9.1, was predicted to result from the actual construction of new capacity and installation of conservation measures, and the operation and maintenance of power plants. The analysis showed a slight decline in operations and maintenance employment, and substantial beneficial effects for construction employment. The construction employment analysis estimated the number of employee years that would be produced by each alternative. No distinction was made between the highly skilled but shorter term employment used for power plant construction, and the less skilled but longer term employment resulting from conservation. The direct employment analysis did not account for the broader economic implications of the alternatives. No distinction was made in this analysis between alternatives that contain special planning provisions for small customers and those that do not because the Energy Policy Act requires the use of IRP principles by small customers for their future resource planning.

The regional economic impacts shown in Section 4.9.2 indicated little change for any one area office's economy as a whole. This analysis accounted for broad economic effects as utility actions affect employment, income, and expenditures. Individual utility systems may experience relatively greater impacts in specific systems. For example, systems that import a high percentage of their power may see improved local economic conditions because conservation programs can keep more of their capital in the community. On the other hand, systems that may have built capacity under the No-Action Alternative may experience negative effects as demand is reduced and capacity is avoided under the Program Alternatives.

4.9.1 Direct Employment

Employment produced from plant operation and maintenance is related to the level of generation expected from each electricity generation type. Employment impacts were estimated by multiplying the factors presented in Table 4.1 by megawatts of power plant generation. Total effects are shown in Part a of Figure 4.24.

Figure 4.24 Regional Operations Employment

The comparison includes the No-Action Alternative and groups of the Program

Alternatives. The figure shows how each alternative differs from the No-Action Alternative in Part b. In comparison with the No-Action Alternative, the Program Alternatives decreased operations employment by about 250 to 380 employees in 2005 and from about 590 to 780 employees in 2015. Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Alternatives 5 and 6 were estimated to reduce operations employees by 780 and 760 employees respectively in 2015.

Employment produced from facility construction is a one-time event, occurring at the time of construction. These estimates were calculated by multiplying the factors presented in Table 4.1 by megawatts of projected new power plant capacity for a variety of technologies. The new capacity was summed for each year between the study years. For example, new capacity summed for the years 1996 through 2005 was used to calculate the construction employment impacts of the alternatives for the year 2005. The impact estimates are shown in Figure 4.25. This figure shows total employment for each alternative in Part a and illustrates how much each differed from the No-Action Alternative in Part b.

Figure 4.25 Regional Construction Employment

The estimates for the No-Action Alternative did not include employment from conservation activities. For the Program Alternatives, reductions in capacity in comparison with the No-Action Alternative were assumed to result from conservation. In terms of conservation, only the differences between the alternatives were considered. If conservation were included in the No-Action Alternative, the same amount would be added to the Program Alternatives. Thus, the differences between the alternatives would remain unchanged from those presented in Figure 4.25.

Capacity reductions from conservation were multiplied by the conservation construction employment factor and added to employment resulting from capacity additions to estimate relative changes in employment in comparison with the No-Action Alternative. The construction employment factor for conservation was 41.7 employee years per megawatt capacity, which is not included in Table 4.1 (Shankle et al. 1992). The conservation factor is not included in Table 4.1 because it is a demand-side resource and does not fit well with the supply-side resources shown in the table. For comparison, traditional coal combustion uses 4.7 employee-years per megawatt to build capacity (Shankle et al. 1992).

Thus, the greater the capacity reductions, the greater the number of employee-years utilized, because of the influence of conservation. The RRIM utility system model assumed that, to the extent needed, utilities would replace lost Western allocation with new supply-side resource capacity. It is possible that no additional energy resources would be needed if the reallocation of Western's power occurred within a unified system of utilities. Conservation activities were held constant at the investment levels for each area office described in Section 4.3.2.1. The Program Alternatives resulted in about 12,400 to 12,700 more employee-years than the No-Action Alternative in the year 2005. For 2015, the difference was about 31,000 to 32,000 employee-years. Potential impacts of the Preferred Alternative are between those of Alternatives 5 and 6. Alternatives 5 and 6 were each estimated to reduce construction employment in 2015 by about 31,000 employees. Taken together over the 20-year study period, the increment between the alternatives amounts to an average of about 2,200 employees per year.

Because of the assumption that utilities would build new supply-side resources to make up the lost Western power and that conservation is fixed across the Program Alternatives, this approach amounts to a worst-case analysis of these impacts. If utilities chose to make up the lost Western allocation using demand-side programs such as conservation, it is likely that the Program Alternatives would have nearly identical impacts.

4.9.2 Regional Economic Impacts

A more detailed examination of the regional economic impacts is presented in this section. Economic impacts in the form of changes in employment, gross output, and labor income were estimated, in addition to the direct construction employment impacts reported in the previous section. The IMPLAN (IMpact analysis for PLANning) regional economic modeling system (Alward and Palmer 1983) was used to estimate the economic impacts reported here.

An economic region was identified for each of Western's five area offices. These economic regions were drawn to fit most closely the actual service territory covered by each area office. The Western customer database was combined with county-level information to determine which county pertained to which area office service territory. Economic regions were formed by aggregating the IMPLAN county-level data for each county within one of the five regions to a single regional economic database for the given area office.

The Program Alternatives were analyzed using RRIM. RRIM estimated the direct effects of the alternatives in terms of changes from the baseline final demand for each region. These outputs from RRIM became inputs to IMPLAN's estimation of economic impacts caused by initial changes in regional final demand.

IMPLAN combines a database of county-level economic information with a regional input-output model to develop customized regional economic models. IMPLAN utilizes the national input-output table maintained by the U.S. Bureau of Economic Analysis (U.S. Department of Commerce 1992). This input-output table is a representation of the inter-industry transactions that occur in the economy. It provides a simplified view of the transactions between industries that occur in the production of goods and services. Trade-flow coefficients are used to adapt the coefficient values of the national table to any custom region of the U.S. economy. Fully disaggregated, the IMPLAN model provides detailed economic information for a 528-sector representation of the desired economic region. Models at the 528-sector level of industry detail were estimated for each of the five area office regions.

Final demand refers to the ultimate consumer purchases from producing industries, after intermediate production occurs. Regional final demand is equivalent to gross regional product or value-added regional industry. Gross output differs in that it is the sum of intermediate and final demand. Labor income refers to income derived from wages, salaries, and benefits. Employment is reported here in terms of full-time equivalent person-years of employment. Impacts on gross output, labor income, and employment are reported in Tables 4.12-4.14.

Table 4.12 Annual Average Percentage Difference in Gross Output Impacts Between the No-Action and Program Alternatives

Area Office Economic Region	2001-2005 PMI Extension	2011-2015 PMI Extension	2001-2005 PMI Limited	2011-2015 PMI Limited
Billings	-0.17	-0.75	-0.17	-0.61
Loveland	-0.23	-0.63	-0.22	-0.52
Phoenix	-0.03	-0.29	-0.03	-0.28
Sacramento	-0.15	-0.26	-0.14	-0.22
Salt Lake City	-0.16	-0.51	-0.16	-0.46

Table 4.13 Annual Average Percentage Difference in Labor Income Impacts Between the No-Action and Program Alternatives

Area Office Economic Region	2001-2005 PMI Extension	2011-2015 PMI Extension	2001-2005 PMI Limited	2011-2015 PMI Limited
Billings	-0.19	-0.84	-0.19	-0.68
Loveland	-0.24	-0.64	-0.22	-0.53
Phoenix	-0.01	-0.24	-0.01	-0.23
Sacramento	-0.13	-0.21	-0.12	-0.18
Salt Lake City	-0.17	-0.50	-0.16	-0.45

Table 4.14 Annual Average Percentage Difference in Employment Impacts Between the No-Action and Program Alternatives

Area Office Economic Region	2001-2005 PMI Extension	2011-2015 PMI Extension	2001-2005 PMI Limited	2011-2015 PMI Limited
Billings	-0.21	-0.94	-0.21	-0.75
Loveland	-0.26	-0.68	-0.24	-0.56
Phoenix	-0.02	-0.25	-0.02	-0.24
Sacramento	-0.13	-0.20	-0.12	-0.17
Salt Lake City	-0.18	-0.56	-0.18	-0.50

Impacts reported in tables 4.12-4.14 are shown in terms of an annual average percentage difference from the baseline case. This was done to facilitate relative comparisons across area offices. The table values implicitly apply for the five-year period indicated, but it should be noted that some years in the period may see impacts while other years have none. The Program Alternatives were estimated to result in slightly negative economic impacts to the affected economic regions. This is due in large part to the negative economic consequences of avoiding or postponing major capacity additions in the future. By avoiding the need for new capacity, the need to bring new plant and equipment on-line is also avoided, and the positive economic impacts that such activities would have simply do not occur or are postponed. The positive economic impacts of engaging in DSM and conservation programs occur when rate savings and rebates are passed onto the residential, commercial and industrial end-users, and when retrofitting construction occurs. However, these positive impacts are outweighed by the negative impacts of avoiding large-scale construction of new capacity, and the overall impacts appear slightly negative. These effects were estimated assuming all other forces in the economies modeled were held to their baseline. Unforeseen events were likely to overshadow the impacts reported as the time horizon lengthened. The fact that impact estimates were reported in terms of nominal dollars means that in real terms the farther into the future, the more the real impacts would diminish.

Also of note are trends implied by the impact estimates. Although the level of impact were negligible in all cases, impacts increased in the negative direction as the projection period lengthened. It is not possible to conclude that this indicates a definite trend, due to the limitations of projecting so far into the future using a static input-output model. Technological innovations over time are likely to change the structure of each regional economy to more than compensate for any implied negative trend shown. There was a more defensible trend indicated by the impact magnitudes across area offices. Area office regions with larger, more diverse, regional economies showed lesser impacts than those with smaller, less diverse, regional economies. The larger economies of the Sacramento and Phoenix areas were more able to mitigate the effects of the Program Alternatives. A region can be said to be more economically diverse than another region simply if it has more industrial sectors represented in its economy. The higher the number of distinct industries, the more diverse the economy. This was true whether impacts were negative or positive.

4.9.3 Environmental Justice

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, became effective on February 11, 1994. The order requires Federal agencies to ensure environmental conditions and human health in minority and low-income communities are considered in Federal decision making, ensure that these communities are not discriminated against by Federal undertakings, and give these communities more information about and greater opportunities to participate in formulating Federal actions which may impact them.

Compliance with this order for most NEPA processes entails identifying and characterizing any such communities which could be impacted by the proposed action, and seeking to involve these communities in the NEPA process by providing information and soliciting input and comments. NEPA impact analyses should identify impacts on these communities and compare and contrast them with impacts outside the communities, if they are discernably different. The process should identify impacts to minority and low-income communities which differ from those to other communities. Impacts can be generically discussed if they are the same for all communities.

The Program is a broad, regional initiative with primary impacts on Western's power customers. The impacts on customers are predominantly economic, and are positive in varying degrees, depending on the alternative, as compared with no action. Historically, possible impacts on minority or low-income communities have been several steps removed from Western's actions, as Western is largely a power wholesaler to utility customers.

Minority and low-income communities do exist within the 15-state region covered by the Program, and could be impacted by changes in retail power rates. Retail power rates for these communities are influenced by many factors: whether or not the utility serving the minority or low-income community has a Western power allocation, the comparative size of the Western allocation, the cost of other power supplies, the transmission and distribution costs of the utility, and other factors. Each individual utility will have a different retail rate, but the rate will be the same for all customers within each rate category (residential, commercial, etc.). Western has no control over utility retail rates beyond ensuring that the benefits of its lower cost power resources ultimately reach the consumer.

Western's Program is intended to apply uniformly to all of its customers with respect to the IRP provision, and on a project-specific basis for the Power Marketing Initiative. Because minority or low-income communities will not be directly affected by Western's proposed action, and because any changes in retail power rates apply equally to all consumers of a given utility, environmental justice was not considered an issue for this proposed action.

Several Native American groups have commented on the Program. In general, the Native American groups want the requirement to have utility status to be waived, and direct allocations of Federal power made to their Tribes. This would allow the Tribes direct access to the economic benefits of Federal power resources. Western views this issue to be an allocation issue rather than an environmental justice issue. The Native American comments are discussed and Western's responses are presented in Appendix G of this EIS. Western has responded favorably to these comments, and has determined that tribal utility status should not be required before a power sales contract can be offered, and will enter into power contracts with Tribes directly.

4.10 RATE IMPACTS

Even though preparation of an IRP would involve a short-term expenditure of funds, long-term benefits often result from the evaluation and selection of cost-effective resources, whether they are supply-side, demand-side, or renewable in nature. Although the unit cost for power may increase as a result of development and implementation of IRP, the consumer's electricity bill may decline due to a smaller amount of power being used as a result of investment in DSM. Longer-term consumer costs should reflect the lower cost of prudent investment in appropriate resources identified through the IRP process.

4.10.1 Long-Term Rate Impacts of Utility Planning

Table 4.15 contains a summary of the estimated rate impacts for two of the Program Alternatives versus the rates produced under the No-Action Alternative. For the three classes of utilities, these were average retail rates across all customer classes in nominal dollars (no adjustment for inflation). The starting point here was the rates reported in Table 4.8 resulting from the No-Action simulations. A dominant result there was that most rates escalated at about the general rate of expected inflation.

Table 4.15 Difference in Retail Rates between No-Action and Program Alternatives (in nominal dollars)

Table 4.15 shows percentage differences in rate levels between the No-Action Alternative and two of the Program Alternatives: the 25-year/98 percent Alternative and the Non-Extension Alternatives. Comparisons for both 2005 and 2015 are shown in the table, but more attention should probably be concentrated on the year 2015. Generally, the impacts from the Program Alternatives are modest relative to those of the No-Action Alternative.

With a few exceptions, the differences in the absolute levels of rates by utility group were so negligible (typically on the order of only 10 to 15 mills by the year 2015) that they could be deemed virtually the same. This observation gains added relevance if one looks at the present value of such small differences in rates occurring roughly 25 years out into the future.

Results from the RRIM simulations showed that the rate impacts do not materially differ across the different areas. The comparatively small differences that appeared emanated from a set of complex interactions that result from load/resource balancing, the mix of Western and supplementary sources of supply for the non-generating sector, and, finally, by the role of DSM resources in meeting the energy service demands of end-users and serving to displace partially thermal capacity additions. Because of so many varied elements, it is unlikely that a uniform Program Alternative applicable to all the areas would have uniform quantitative impacts across each of the areas. Additionally, the estimated impacts in 2015 were typically greater than those estimated for 2005 because the cumulative impacts of the programs over 20 years allowed more complete adjustment to the long-run equilibrium expansion paths of the utility systems.

Results in Table 4.15 for the year 2015, show that retail rate impacts under the Program Alternatives reflect a fairly consistent qualitative picture. First, all the generating public utility sectors saw modest decreases in average retail rates, with all the areas falling within a narrow band of -9.5 percent (Sacramento) to -13.6 percent (Loveland). The rate impacts on the non-generating utility sector were found to be slightly more mixed. With the exception ofthe non-generators in Sacramento, the rate impacts were found to be smaller in absolute size than the impacts on the generating publics, ranging from nearly -8 percent in the Phoenix area to about 5 percent in Loveland. This varied response can be attributed to the relative blend of resource supplies serving this sector and the impacts of DSM resources on retail loads. In addition, relative impacts on the generating publics were also larger due to production representing a greater portion of their activities, in contrast to the distribution-oriented activities of the non-generators. In the Billings, Loveland, and Salt Lake City areas, the Program Alternatives reflected the impacts of increased emphasis on DSM (although the rate impact on non-generators is barely perceptible). Conventional utility rate-making maintains that DSM could be expected to cause retail rates to rise slightly due to the combined effects from the cost of conservation measures, short-run marginal generation costs, and reduced retail sales (in Hirst [1991]). These effects, however, were not found to be as significant in the Phoenix and Sacramento areas, where the net result of all the factors affecting average system costs was found to be modestly negative.

The investor-owned utility sector is not directly affected by the Program. However, because of interconnection and coordination, some indirect impacts may be registered. In all the Program Alternative simulations with RRIM, these indirect impacts were negligible as reflected in Table 4.15.

There were slight impacts from the Program Alternatives on Western's wholesale rates, the absolute differences ran from 0 to only 6 mills/kWh by the year 2015.

The contract Extension Alternatives showed a smaller impact. In general, if the amount of power Western could guarantee in the future was fairly high, utilities could put off new capacity and retain the rate reductions caused by the conservation programs (see Table 4.15).

Table 4.16 Estimated Total Cost for Western Customers to Develop an IRP

Less than 50 GWh	$5,000-$3,000 (about 425 customers fall in this range)
51 to 99 GWh	$25,000-$60,000 (about 130 customers fall in this range)
100 to 999 GWh	$50,000-$300,000 (about 140 customers fall in this range)
Greater than 1,000 GWh	$200,000-$800,000+ (about 40 customers fall in this range)

Table 4.17 Estimates of Incremental Cost for Western Customers to Develop an IRP

Customer Size (annual sales)	Estimated Incremental IRP Cost (high end)	Estimated Incremental IRP Cost (low end)
Less than 50 GWh	$21,000	$2,000
51 to 99 GWh	$42,000	$10,000
100 to 999 GWh	$210,000	$20,000
Greater than 1,000 GWh	$560,000+	$80,000

4.10.2 Short-Term Rate Impacts of Utility Planning

In this section estimates of the costs of Western's planning requirements to its customers and the resulting rate impacts to energy end users are presented. In this analysis the incremental cost for Western customers to develop an IRP was estimated. This incremental cost was defined as the probable cost differential between customers' current resource planning efforts and the total cost of IRP efforts conducted under Western's proposed energy planning and management requirements.

This estimate was made within the following constraints and factors:

* There was a lack of detailed data regarding customers' current resource planning efforts (including total costs for those who have already developed IRPs, current resource planning efforts as compared to planning requirements, etc.).
* The vast diversity of Western's customer base made it difficult to generalize about the incremental cost of doing IRP. Because of this diversity, there is likely to be considerable variation in the incremental cost of IRP for different Western customers.
* This analysis was general in nature and did not address a number of important considerations, such as the time frame/frequency of the estimated expenditures (e.g., one time versus every five years), the potential that savings resulting from improved resource planning should more than offset the cost of the planning effort, or the cost advantages that could result from joint preparation of IRPs.

This analysis presented estimated total and incremental IRP costs for various customer size groupings. While IRP costs did not consistently correlate with size in many cases, the analysis provided a simple framework for establishing costs based on an understanding of the range of customers served by Western. The analysis was intended to provide a probable value for the majority of customers, and was not intended to apply to all customers given the extensive variation in customer characteristics.

Table 4.16 presents estimated total IRP costs for four customer size groupings. As shown, total IRP costs were likely to range from $5,000 to more than $800,000, depending on customer characteristics. In the absence of better information, these estimates reflect Western's best judgment about reasonable and necessary IRP expenditures for the majority of customers falling within each size category. In addition, limited information about the cost of IRPs already developed by several Western customers was used to "test" and refine the estimates of total IRP costs, which are presented in Table 4.16. "Customers," as used in this analysis, include parent-type entities and their members.

Western's customers are already involved in various levels of planning activities. (See Section 3.6 for a discussion of current planning requirements and activities.) Here the focus was on calculating the incremental costs of planning that were likely to be beyond customers' current planning efforts. This involved first estimating the difference between current planning and full IRP for the majority of Western customers and then reducing the total IRP cost values to reflect only incremental efforts. Western has defined the following seven required elements for compliance with its proposed IRP initiatives:

* Identify/compare resource options
* Develop two-year and five-year action plans
* Use least-cost options
* Minimize adverse environmental impacts of new resources
* Full public participation
* Include load forecasting
* Provide predicted performance validation methods.

The majority of Western's customers are currently conducting an estimated 30 to 60 percent of the required IRP elements, with the additional 40 to 70 percent of the IRP effort remaining to be developed.

Table 4.17 presents a range of estimates of the incremental cost of developing an IRP. The higher values were developed by multiplying high end values for the total IRP cost from Table 4.13 by 70 percent, which reflected the high end of the estimated incremental cost percentages. As shown, the high end of incremental IRP costs for Western customers was likely to range from $21,000 to more than $560,000, depending on customer characteristics. For comparison, low-end costs are also shown in Table 4.17. These were calculated by multiplying the low-end values from Table 4.13 by 40 percent.

Using the high-end cost estimates presented in Table 4.17 and the range of utility sizes presented in Table 4.16, Western estimated the potential average short-term rate impact assuming that all costs were incurred in one year and that they were passed on to end-use customers. Western found that the costs ranged from 0.21 mills/kwh to 2.1 mills/kwh as indicated below. A small number of examples based on actual experience produced costs either below or at the low end of this range.

Customers with Annual Sales of <50 GWh

$21,000/10 GWh (a conservative estimate of customer annual sales for systems less that 50 GWh) = $0.021/MWh = 2.1 mills/kWh

$21,000/50 GWh = $0.00042 = 0.42 mills/kWh

Range: 0.42 to 2.1 mills/kWh

Customers with Annual Sales of 50 to 99 GWh

$42,000/50 GWh = 0.084 mills/kWh

$42,000/99 GWh = 0.042 mills/kWh

Range: 0.42 to 0.84 mills/kWh

Customers with Annual Sales of 100 to 999 GWh

$210,000/100 GWh = 2.1 mills/kWh

$210,000/999 GWh = 0.21 mills/kWh

Range: 0.21 to 2.1 mills/kWh

Customers with Annual Sales of >1,000 GWh

$560,000/1,000 GWh = 0.56 mills/kWh

Range: A range could not be determined because maximum costs and loads are unknown.

The limited information that exists on the actual cost of customer preparation of IRP was consistent with this analysis. For example, the Wyoming Municipal Power Agency developed an IRP for its eight member cities at a cost of $80,000. For the town of Guernsey, Wyoming, a member of the Wyoming Municipal Power Agency, it was estimated that the prorated share of the total IRP cost would be approximately $5,000. In the recent past, Guernsey had a load of about 8 GWh.

The Kansas City Board of Public Utilities, a municipal utility with a load of approximately 2,500 GWh, estimated its cost of IRP preparation at $800,000. However, an official at this utility emphasized that this expense was more than offset by the benefits that resulted from IRP implementation. These benefits included avoiding the cost of building generating resources and increasing certainty in the utility's planning.

4.10.3 Reduction in Firm Power Allocation

The RRIM model took into account the different percentages of extension to existing long-term firm power customers. Because customers would likely need to purchase non-Federal power if Western's resources were not fully extended, Western has estimated the monetary impact of those purchases.

The dollar impacts to Western's customers when faced with losing 10 percent of available firm power were calculated as gross figures for each of the five areas overseen by Western's area offices. To the extent that a 10-percent reduction in firm power was the greatest reduction incorporated in the alternatives, the analysis in this section amounted to a reasonable worst-case scenario.

The following steps were taken to calculate the impacts of the firm power reduction.

1. Sum the total of Western's firm sales to preference customers by area.1
2. Calculate 10 percent of total firm sales.
3. Choose the project composite rate for the respective area office.
4. Calculate the average rate of wholesale sales for resale over all available sellers.2
5. Calculate the difference in rates (opportunity cost) faced by Western's customers by subtracting Western's composite rate from the average rate of wholesale sales for resale for the respective area.
6. Multiply the difference in rates by the 10-percent reduction in firm sales for the dollar impact to customers of a 10-percent reduction in firm power.

The average rate of sales for resale represented an average of rates that a customer might face in order to make up that power lost due to the hypothetical reduction in firm Western power. The values were derived by averaging the rates offered by those utilities providing wholesale power in states that were included in an area office's marketing area. The dollar impact could be thought of as the additional expense incurred by Western's customers as a result of the reduction in available firm power. Table 4.18 summarizes the results.

Table 4.18 Dollar Expense to Western Customers of a 10% Reduction in Available Western Firm Power

Area	Expense to Western Customers of 10% Reduction in Firm Power	Average Wholesale Rate for Non-Federal Power (mills/kWh)	Western Composite Rate (1991) (mills/kWh)
Billings	$18,959,565	33.76	11.25
Loveland	$3,213,603	34.96	19.17
Phoenix	$10,371,252	37.82	9.03 & 10.21
Sacramento	$14,360,595	50.79	32.60
Salt Lake City	$11,210,610	36.13	16.20

The impact to individual utilities of the regional expense was a function of the percentage of total load purchased from Western by each utility. Those purchasing a high percentage from Western would experience a proportionately higher impact in expenses due to purchasing the compensating amount of power necessary to fulfill their obligations. Likewise, utilities purchasing a lower percentage of total load from Western would experience a lesser impact. The impact of the increased purchase power expense on ultimate consumers would vary according to the impact on their respective supplying utility.

4.11 ORGANIZATIONAL IMPACTS

Early in the EIS scoping process for Western's proposed Program, feedback from various organizations made it clear that potential programmatic impacts included a range of effects that would alter the ways in which the organizations operated. Many of these effects are not readily quantified, yet they could have significant consequences for Western's customers and could alter their behavior substantially. The abundance of comments on these impacts and the magnitude of concerns raised about some of them convinced Western that these impacts should be analyzed in the draft EIS.1

A review of these comments indicated four impact types: administrative burden, equity, flexibility, and risk/uncertainty. All four types related to how the affected organizations would operate once a program was in place. Because the impacts were difficult to quantify, several complementary analysis techniques were used to identify and assess them. By using these techniques, estimates of the relative quantitative measures of the impacts were possible and comments that explained the quantitative results were available (Lee et al. 1993).

The organizational impacts of Western's alternatives were analyzed using data collected from meetings with several groups of Western's customers. Although the participating customers were not chosen to be a statistically representative sample, they did represent all customer types (e.g., municipal utilities, Federal facilities, rural electric cooperatives, MBAs, etc.). Because the burden of carrying out the requirements of the Program Alternative selected would lie with Western's customers, this section focuses on organizational impacts on the customers.

The customer organizational impacts were assessed based on interviews, responses to a questionnaire, and results from a conjoint, or tradeoff, analysis. The conjoint analysis required participants to rate hypothetical program designs in terms of their organizational impacts and the participants' overall preferences. The conjoint analysis results provided numerical estimates of program impacts that not only allowed Western to assess impacts, but also permitted Western to identify customers who were similar for categorization purposes. A technique to categorize organizations based on their similarities was developed so that the data could be used to generalize the impact estimates to all members of that category.

Several customer characteristics were analyzed to determine if the customers could be aggregated into a small number of categories. The characteristics analyzed included location, size, type, and share of electricity provided by Western. Only two customer characteristics were determined to have a statistically significant effect on the conjoint analysis results: location and share of electricity provided by Western.

4.11.1 Importance of Program Components

In the conjoint analysis customers were asked to rate various program components for their impacts on the customers' operations. These program components included the EMP, contract extension period, percentage of resource extended, contract adjustment provisions, and penalty options. Table 4.19 presents average results for all participating customers, showing how important they felt each program component was in determining the administrative burden, equity, flexibility, and risk/uncertainty impacts.

Table 4.19 Importance of Program Components in Impacts Averaged Over all Cutomers

	Organizational Impact			
Program Component	Administrative Burden	Equity	Flexibility	Risk/ Uncertainty
IRP	54%	29%	20%	17%
Extension Period	24%	30%	25%	38%
Percentage extension	10%	29%	25%	25%
Adjustment Provision	6%	3%	3%	5%
Penalty	6%	10%	8%	15%

Administrative burden impacts are those that affect the administrative workload and other labor and resource requirements. Specific types of customer impacts in this category include preparation of reports to document program compliance, and labor, special expertise, and other resource requirements for preparing IRPs.

Equity impacts are those associated with how fair the program is in its effects on different customers. Specific examples of customer equity impacts include reasonableness and fairness of the requirements in the context of customer size and type, consideration of a customer's local economic conditions, and consideration of a customer's previous expenditures on energy management measures.

Flexibility impacts involve how much adaptability Western builds into the implementation of its program. Examples of measures of flexibility include the extent to which the program allows customers to choose different ways to comply, different reporting formats, and alternative ways to quantify energy savings.

Risk and uncertainty impacts in this context are associated with how the program affects the general ability of a customer to plan and operate its system effectively. The more usual risk and uncertainty concerns of utilities involving loss of load and power supply interruptions are not components of risk and uncertainty in the organizational analysis context. Examples of the types of risk and uncertainty addressed include financial risk associated with any additional amounts of staff time required, possible adjustments in the terms or amounts of future sales from Western to customers, and possible penalties that Western might impose for non-compliance.

For all customers, the IRP component had the largest effect on the administrative burden impact. The extension period, IRP provision, and percentage extension options tended to be the most influential for the other impact types. The adjustment provisions had a relatively insignificant influence on the organizational impacts. The penalty provisions were relatively important in risk and uncertainty impacts.

In addition to specific impacts, customer preferences were analyzed for different program components to provide insights into how customers might respond to the Program Alternatives being considered by Western (see Table 4.20). On the average the percentage extension component played the largest role in determining program preferences. The extension period and IRP options had the second and third largest effect on preferences. On the average, the penalty provisions had the next largest effect on preferences. The adjustment provisions had a minimal effect on preferences.

Table 4.20 Importance of Program Components in Overall Preferences Averaged over all Customers

Program Component	Importance
IRP	22%
Extension Period	24%
Percentage extension	39%
Adjustment Provision	3%
Penalty	11%

4.11.2 Organizational Impacts of Western's Program Alternatives

The results of the conjoint analysis were used to estimate the relative impacts of each of the EIS Program Alternatives. The impacts were measured with respect to the best and worst possible combinations of program components.

Table 4.21 summarizes the organizational impacts of the 13 alternatives averaged for all Western customers. The Preferred Alternative is treated as a combination of Alternatives 5 and 6. It was not actually modeled. For purposes of this analysis, impact values for Alternatives 1, 9, 10, 11, and 12 were calculated assuming a 25-year extension period.

Table 4.21 Impacts of Draft EIS Alternatives

In calculating impacts for Alternatives 9 and 10, a 25-year extension period was assumed, coupled with a 90 percent resource extension (to take effect after the 10-year bridging period).1 Data for effects of the penalty provision specified by the Energy Policy Act of 1992 were unavailable. At the time of data collection, customers were given a rate penalty option similar to but different from that of the Energy Policy Act of 1992. The penalty provision contained in the Act was considered to be intermediate between the No-Action and the original provision. To accommodate this change in the alternatives, the average value for the penalty provision effect was used to calculate values for all alternatives except for the No-Action Alternative.

The No-Action Alternative had the "best" impacts on administrative burden. The customers considered the administrative burden to be most severe for Program Alternatives that require all customers to prepare an IRP (Alternatives 2, 3, 4, 8, 9, and 11; see Table 2.5 for a description of these alternatives). The administrative burden tended to be less for options that included a small customer provision. Administrative burdens were aggravated by shorter contract extension periods, but the effect was fairly minimal for the Program Alternatives because of the offsetting benefits of larger extension percentages.

Averaged across all customers, equity impacts for the No-Action Alternative were "best." The alternatives (5, 6, 7, 10, and 12) that include the small customer provision tended to be rated as more equitable than alternatives requiring all customers to prepare an IRP. Overall, there was very little variation in the equity impacts across the alternatives. All alternatives except the No-Action Alternative rated "average" or "worse-than-average" equity impacts, probably as a result of increased cost, time, and reporting requirements for Western's customers.

The flexibility of the No-Action Alternative was rated "best" by all customers together. The IRP-only alternatives (2, 3, 4, 8, 9, and 11) were considered to be less flexible than the other alternatives, and alternatives that included the small customer provision (5, 6, 7, 10, and 12) received the highest flexibility marks of the Program Alternatives. Alternative 9, one of the Limited Extension Alternatives, received a "worst" rating in the flexibility impact category due to the undesirable impacts of an IRP requirement, exacerbated by a low percentage extension. A relatively long extension period (25 years), assumed after the expiration of the 10-year Limited Extension, was not able to compensate for this unfavorable combination. Alternative 8 was rated "average" by customers overall in terms of flexibility impacts.

There was some variation in how the alternatives performed in terms of customer risk and uncertainty, from "best" to "worse." The No-Action Alternative was considered to be "best" by customers overall. Customers considered any of the IRP requirements to increase their risk relative to the current C&RE requirement, but differences in the effects of the IRP options were relatively small. For the customers overall, Alternative 8 was rated as having "average" risk and uncertainty impacts.

4.11.3 Program Design Preferences

As noted earlier, the organizational impacts analysis was also designed to assess customer preferences for different combinations of program components. Customer preferences averaged across all customers are shown in Table 4.22. The resource percentage extension component had the largest effect on customers' overall preferences. The No-Action Alternative got the highest ratings, primarily from the favorable impacts of the 100-percent resource extension. Alternatives with the 90-percent resource extension (Alternatives 4 and 7; 90-percent was assumed for Alternatives 9 and 10 after the 10-year contract extension for analytical purposes; see Table 2.5 for a definition of these alternatives), which is the lowest resource extension percentage considered, were less preferred than those with higher percentage resource extensions. Customers preferred the alternatives that had the longest extension periods, but the effect was attenuated by the fact that Western's alternatives coupled longer extension periods with smaller extension percentages, which were perceived as undesirable. Alternatives 4 and 9 were rated "worst" overall due to an IRP requirement for all customers and the smallest percentage extension. Although Alternative 10 included the small customer provision, it was still rated in the "worst" category due to its assumed low percentage extension. Overall, the 90-percent resource extension seemed to be the most unfavorable component level, and customers rated all the alternatives with the 90-percent resource extension as the "worst" alternatives.

Table 4.22 Preferences Averaged Over All Western Customers

4.11.4 Conclusions

In general, customers rated the impacts of the No-Action Alternative "best" when compared with the impacts of the other alternatives. This was primarily due to longer resource extension periods and the assumed higher extension percentage. For the PMI Extension Alternatives, those that required an IRP with no small customer provision generally were perceived more unfavorably than those that included the small customer provision. Alternative 8 generally had "average" impacts from the customers' perspective. The PMI Limited Extension Alternatives tended to have unfavorable impacts due to the assumed 90-percent resource extension. Since the PMI Non-Extension Alternatives are identical to the No-Action Alternative with the exception of the IRP component, they also tended to be perceived more favorably.

Overall, customers appeared to consider any change from the status quo as having the potential for undesirable impacts. In the data collection meetings conducted for this analysis, customers frequently asked what was meant by IRP, how it would be enforced, why the "stick" was being used instead of the "carrot," and why the current approach needed to be changed. They often voiced a preference for incentives to encourage satisfying Western's requirements, instead of a rate penalty; however, with passage of the Energy Policy Act of 1992, a rate penalty is required.

Western's customers viewed alternatives with the smallest percentage extension as the least preferred. (Alternatives 4 and 7 were 90-percent; 90-percent was assumed for Alternatives 9 and 10 after the 10-year contract extension for analytical purposes; see Table 2.5 for a definition of these alternatives.) Many of the Program Alternatives proposed by Western attempted to strike a balance between components and narrow the range of impacts on Western's customers; shorter extension periods were combined with larger percentage extensions. However, when combined with the effect of a 90-percent resource extension, the positive impact of a longer extension period was not enough to offset the effect of the 90-percent extension in Alternative 4 and assumed for Alternatives 9 and 10. Because Alternative 8 tended to strike a middle ground in its design it appeared to be acceptable to the customers. Although Western's Preferred Alternative calls for less than a 25-year extension period, its 18-20-year extension approaches the 25-year length indicated by customers as the minimum desired. The 18-20-year period also allows for more flexibility on Western's behalf.

4.12 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES

The alternatives under consideration do not in themselves commit resources, but, by encouraging utility planning processes, Western hopes to minimize irreversible and irretrievable environmental impacts resulting from utilities' decisions to generate electricity or manage their loads. Implementation of the Program would commit human resources to energy management planning.

4.13 UNAVOIDABLE ADVERSE IMPACTS

The alternatives analyzed in this EIS establish energy planning requirements and power marketing criteria for Western's customers. Taken by themselves, these actions would result in few unavoidable adverse impacts. The one area in which impacts are likely to occur is in the organizational features of Western's customers. Impacts to organizational qualities such as equity, flexibility, administrative burden, and risk and uncertainty are described in Section 4.11.

Another impact that would result from the planning requirements is the cost of preparing the plans. These costs are likely to be passed on to electricity end users. Potential increases in electricity costs resulting from planning activities are described in Section 4.10.

Some features of the alternatives may result in Western shifting the allocation of Federal energy among customers. The resource pool component of the PMI would allow Western to allocate a small percentage of its current resources to new customers. The environmental impacts of this shift were captured in the analyses on an area-wide level. In some instances, localized impacts may not have been captured by the analysis. For example, if one utility gets a decrease in Western power, it may compensate by increasing its generating capability. As local resource acquisition decisions are made, environmental impacts would be determined through permitting, licensing, and siting procedures. These procedures would probably not involve Western. On an area wide level, this increased generation in one locale may be offset by a decrease in generation somewhere else within the same marketing area.

The likelihood of a localized impact is also diminished because most utilities purchase their supplemental power from investor-owned utilities or associations of public utilities. Under these arrangements, the reallocation of Federal power may simply result in a central source sending more or less power to some members of its customer base, without the construction or decommissioning of power plants.

4.14 RELATIONSHIP BETWEEN SHORT-TERM USES AND LONG-TERM PRODUCTIVITY

All of the Program Alternatives would require Western customers to prepare utility plans. These plans would assess all resources available to a utility to meet its load, including conservation and renewable technologies. The costs of preparing these plans is discussed in Section 4.10. To the extent that these costs must be borne by electricity consumers, there would be a decrease in the disposable income and capital available for investment. However, these costs would be minimal and would likely be offset by savings from improved energy resource acquisitions. Plan implementation may result in rate decreases over time (see Section 4.10). These cost savings would, over the long run, more than offset the short-term costs of preparing the plans. Further, as the analysis in this EIS demonstrates, environmental and economic benefits would result.

4.15 DIRECT AND INDIRECT EFFECTS

Direct effects of Western's proposed alternatives include organizational impacts on Western's customers and impacts resulting from Western's re-allocating small portions of its Federal energy.

Most of the effects addressed by this EIS are indirect. Indirect effects include the energy resource acquisition decisions that Western's customers may make as a result of planning and power marketing criteria. To the extent that the plans encourage conservation, renewable energy resources, and an assessment of environmental impacts, the alternatives would likely reduce the need for fossil fuel and nuclear power plants. Estimates of the environmental effects of these tradeoffs are presented in Sections 4.4 through 4.9.

4.16 CUMULATIVE EFFECTS

The model impact analysis was based not just on the Program, but also on predicted trends in the energy industry as a whole. The model outputs aggregated these changes. The analysis of the alternatives in this EIS was designed to address the cumulative impacts of energy resource acquisition by Western's customers. Impacts were estimated for each of Western's area office jurisdictions, and summed to describe impacts to Western's entire service region. These effects are described in Sections 4.4 through 4.9 of this chapter.

4.17 ENVIRONMENTAL CONSULTATION, REVIEW, AND PERMIT REQUIREMENTS

Western developed the proposed Program through an extensive public participation process, holding 53 public meetings and workshops and distributing a series of Program newsletters. This EIS was prepared pursuant to 40 CFR Parts 1500-1508, which required Federal agencies to assess the impacts that their actions may have on the environment and to integrate this assessment into agency planning and decision-making at the earliest possible time.

In addition to their responsibilities under NEPA, Federal agencies are required to carry out the provisions of other Federal environmental laws. The Federal actions related to the alternatives in this EIS do not require any particular response with regard to other Federal laws.

The alternatives in this EIS apply to broad policy decisions related to Western's power marketing and requirements for customers' energy planning. By themselves, these policy decisions are not directly affected by Federal environmental laws. As a result of the planning requirements, utilities may decide to change the way they acquire or operate resources. These changes in decisions would result from increased awareness of electricity generation and conservation resource options and better information about the resource's fit to a particular utility's system. However, these decisions will be made by the utilities. Impacts described in this EIS are based on a judgment about utilities' potential future actions.

As specific activities are chosen, additional environmental analyses may be necessary. Western will complete this analysis for the resources that the agency initiates. Most, if not all, of the activities would be proposed and built by individual utilities or utility-based associations. For these non-Federal projects, environmental analysis and documentation would conform to applicable Federal and state laws and regulations. At the time of the resource decisions, utilities would be responsible for preparing and complying with site-specific permits and documents as necessary and required.

Western concludes that no further action for this programmatic decision is needed to comply with the following Federal laws and regulations:

* The Endangered Species Act of 1973, as amended, (16 USC 1536).
* Fish and Wildlife Conservation Act of 1980 (16 USC 2901 et seq.).
* Cultural Resource Conservation - A number of Federal laws and regulation have been promulgated to protect the nation's historical, cultural, and prehistoric resources.
* Executive Order 12372, State, Area-Wide, and Local Plan and Program Consistency-A list of the individuals, clearinghouses, agencies, and organizations

receiving copies of this document is included in Chapter 5 of this draft EIS. This list was compiled to satisfy review and consultation requirements and to ensure consistency with regional, state, and local permitting and planning.

* Coastal Zone Management Act of 1972.
* Executive Order 11988, Floodplains Management.
* Executive Order 11990, Protection of Wetlands - Wetlands are discussed in Chapter 3 of this draft EIS.
* The Farmland Protection Policy Act (7 USC 4201 et seq.).
* Permits for Structures in Navigable Waters, Section 10 under the Rivers and Harbors Appropriations Act of 1899.
* Permits of Discharges into Waters of the United States, Section 404 of the Clean Water Act.
* Permits for Rights-of-Way on Public Land under the Federal Land Policy and Management Act (43 USC 1701 et seq.).
* Energy Conservation at Federal Facilities-Western's facilities are outside the scope of this draft EIS. Federal facilities that are Western customers would be required to abide by the final regulations.
* Pollution Control at Federal Facilities as required by The Clean Water Act, as amended (42 USC 7401, et seq.; 33 USC 1251 et seq.); The Safe Drinking Water Act, as amended (42 USC 300 F et seq.); the "Grand Junction Remedial Action Criteria (10 CFR 712); Environmental Radiation Protection Standards for Nuclear Power Operations and other nuclear materials safeguards (40 CFR 190; 40 CFR 191; 40 CFR 192); The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 USC 9601 [9615] et seq.); The Federal Insecticide, Fungicide, and Rodenticide Act, as amended (7 USC 136 et seq.); The Resource Conservation and Recovery Act of 1976, as amended (42 USC 6901 et seq.); The Toxic Substances Control Act, as amended (40 CFR 761); and The Noise Control Act of 1972, as amended (42 USC 4901 et seq.).
* The Wilderness Act, as amended (16 USC 1131).
* Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, February 11, 1994. Published in the Federal Register February 15, 1994-59 FR 7829.

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CHAPTER 8 GLOSSARY

Administrator   The Administrator of the Western Area Power Administration.

Applicable Integrated Resource Plan   For any customer, an applicable integrated resource plan is the IRP approved by the Administrator for that customer under the Energy Policy Act of 1992.

Avoided Cost   An investment guideline describing the value of conservation and generation resource investments in terms of the cost of more expensive resources that would otherwise have to be acquired.

Base Loaded Resources   Baseloaded electricity generating resources are those that generally are operated continually except for maintenance and unscheduled outages.

Btu (British thermal unit)   The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit (3,413 Btus are equal to one kilowatthour).

C&RE   Conservation and Renewable Energy.

Capacity   The maximum power that a machine or system can produce or carry under specified conditions. The capacity of generating equipment is generally expressed in kilowatts or megawatts. In terms of transmission lines, capacity refers to the maximum load a line is capable of carrying under specified conditions.

Coal Gasification   The process of converting coal to a synthetic gaseous fuel.

Cogeneration   The sequential production of electricity and useful thermal energy. This is frequently accomplished by the recovery of reject heat from an electric generating plant for use in industrial processes, space or water heating applications. Conversely, cogeneration can be accomplished by using reject heat from industrial processes to power an electricity generator.

Combined-Cycle Combustion Turbine (CCCT)   The combination of a gas turbine and a steam turbine
in an electric Turbine (CCCT)   generation plant. The waste heat from the gas turbine provides the
heat energy for the steam turbine.

Conservation   A reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution.

Cost of Debt   The amount paid to the holders of debt (bonds and other securities) for use of their money. Generally expressed as an annual percentage.

Cost of Equity   Earnings expected by a shareholder on an investment in a company. Generally expressed as an annual percentage in this plan.

Cumulative Impact   The impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

Customer   Any entity or entities purchasing firm capacity, with or without energy, from Western under a long-term firm power service contract. Such terms include parent-type entities and their distribution or user members. Western has more than 600 wholesale customers, such as cooperatives, municipalities, Federal and state agencies, and member-based associations.

Debt   Investment funds raised through the sale of securities having fixed rates of interest.

Debt/Equity Ratio   The ratio of debt financing to equity financing used for capital investment.

Demand Forecast   An estimate of the level of energy that is likely to be needed at some time in the future.

Demand Side Management   Utility programs and policies that attempt to influence the end-use consumption of energy.

Direct Current (DC)   An electrical current in which the electrons flow continuously in one direction. Direct current is used in specialized applications in commercial electric generation, transmission, and distribution systems.

Direct Effects Same as "direct impacts." Effects that are caused by the action and occur at the same time and place. See Effects.

Discount Rate The rate used in a formula to convert future costs or benefits to their present value.

Dispatch Operating control of an integrated electrical system involving operations such as control of the operation of high-voltage lines, substations, or other equipment.

Distribution The transfer of electricity from the transmission network to the consumer. Distribution systems generally include the equipment to transfer power from the substation to the customer's meter.

DSC DSC is debt service coverage, which is the ratio of the sum of depreciation and amortization expense, interest on long-term debt, and the patronage capital or margins to the debt service billed. The Rural Electrification Administration sets a minimum level for this measure for its borrowers.

Effects As used in NEPA documentation, the terms effects and impacts are synonymous. Effects can be ecological (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, economic, social, or health, whether direct, indirect, or cumulative. Effects may also include those resulting from actions which may have both beneficial and detrimental effects, even if on balance the agency believes that the effect will be beneficial.

End Use A term referring to the final use of energy. In general, it can be used in the same way as the term "energy demand." In more detailed use it often refers to a specific energy service (for example, space heating) or type of energy-consuming equipment (for example, a washing machine or electric motor).

Energy That which does, or is capable of doing, work. Energy is measured in terms of the work it is capable of doing. Electrical energy is commonly measured in kilowatthours.

Externality Any costs or benefits of goods or services that are not accounted for in the price of the goods or services. Specifically, the term given to the effects of pollution and other environmental effects from power plants or conservation measures.

Fuel Cycle The series of steps required to produce electricity from power plants. The fuel cycle includes mining or otherwise acquiring the raw fuel source, processing and cleaning the fuel, transporting, generating, waste management, and plant decommissioning.

G&AC Guidelines and Acceptance Criteria. These are the criteria that Western's customers complied with under the previous Conservation and Renewable Energy Program. They were published in 50 FR 33892 (August 21, 1985) which is printed in appendix B.

Generation The act or process of producing electricity from other forms of energy.

Geothermal Useful energy derived from the natural heat of the earth as manifested by hot rocks, hot water, hot brines, or steam.

Heat Rate The amount of input (fuel) energy required by a power plant to produce one kilowatthour of electrical output. Expressed as Btu/kWh in this plan.

Heating Degree Days A measure of the amount of heat needed in a building over a fixed period of time, usually a year. Heating degree days per day are calculated by subtracting from a fixed temperature the average temperature over the day. Historically, the fixed temperature has been set at 65 degrees Fahrenheit, the outdoor temperature below which heat was typically needed. As an example, a day with an average temperature of 45 degrees Fahrenheit would have 20 heating degree days, assuming a base of 65 degrees Fahrenheit.

Hydroelectric Power The generation of electricity using falling water to turn turbo-electric generators.

Indirect Effects Same as "indirect impacts." Indirect effects are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable. Indirect effects may include growth-inducing effects and other effects related to induced changes in the pattern of land use, population density, or growth rate, and related effects on air and water and other natural systems, including ecosystems.

Insolation The rate of energy from the sun falling on the earth's surface, typically measured in watts per square meter.

Integrated Resource Planning According to the Energy Policy Act of 1992, a planning process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to a utility's electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

Investor-Owned Utility A utility that is organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Irrigation District An irrigation district performs only an irrigation function. If other electrical functions are performed, such as residential service or other utility responsibilities, the district may be considered a utility. The term irrigation districts may include agricultural types of districts, such as electrical districts, water delivery districts, and water conservation districts.

Kilowatt (kW) The electrical unit of power that equals 1,000 watts.

Kilowatthour (kWh) A basic unit of electrical energy that equals one kilowatt of power applied for one hour.

Least Cost Option According to the Energy Policy Act of 1992, an option for providing reliable electric services to electric customers which will, to the extent practicable, minimize life-cycle system costs, including adverse environmental effects, of providing such service. To the extent practicable, energy efficiency and renewable resources may be given priority in any least-cost option.

Least-Cost Planning Another term for integrated resource planning.

Levelized Life-Cycle Cost The present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. This stream of payments can be converted to a unit cost of energy by dividing them by the number of kilwwatthours produced or saved by the resource in associated years. By levelizing costs, resources with different lifetimes and generating capabilities can be compared.

Life-Cycle Costs See "levelized life-cycle cost."

Load The amount of electric power required at a given point on a system.

Load Forecast An estimate of the level of energy that must be generated to meet a need. This differs from a demand forecast in that transmission and distribution losses from the generator to the customer are included.

Long-Term Firm Power Service Contract Any contract for the sale by Western of firm capacity, with
or without energy, which is to be delivered over a period of more than one year.

Marginal Cost The cost of producing the last unit of energy (the long-run incremental cost of production).

Marketable Resources The amount of electric power from Federal generation projects available for Western to market.

Megawatt (MW) The electrical unit of power that equals one million watts or one thousand kilowatts.

Member Based Association An organization of member utilities organized to serve supply, distribution, or service needs. These organizations are sometimes referred to as parent-type entities.

Mill A tenth of a cent. The cost of electricity is often given in mills per kilowatthour.

Municipal Solid Waste (MSW) Refuse offering the potential for energy recovery. Technically, residential, commercial, and institutional discards.

Nominal Dollars Dollars that include the effects of inflation. These are dollars that, at the time they are spent, have no adjustments made for the amount of inflation that has affected their value over time.

Nonfirm Energy Energy that is available in the near-term, but may not be available over a long period of time, or may be interrupted under certain circumstances.

Peak Capacity The maximum capacity of a system to meet loads.

Peak Demand The highest demand for power during a stated period of time.

Percent Allocation The percentage of marketable resources available for extension at the time of contract renewal.

Performance Plan A utility planning approach based on the utility meeting and documenting a prescribed level of conservation or renewable energy activity.

Photovoltaic Direct conversion of sunlight to electric energy through the effects of solar radiation on semi-conductor materials.

Preference Priority access to Federal power by public bodies and cooperatives.

Present Value The worth of future returns or costs in terms of their current value. To obtain a present value, an interest rate is used to discount these future returns and costs.

Public Utility Commissions State agencies whose purpose is to regulate, among others, investor-owned utilities operating in the state with a protected monopoly to supply power in assigned service territories.

Real Dollars Dollars that do not include the effects of inflation. They represent constant purchasing power.

Reliability The ability of the power system to provide customers uninterrupted electric service. Includes generation, transmission, and distribution reliability.

Renewable Resource A resource that uses solar, wind, water (hydroelectric), geothermal, biomass or similar sources of energy, and that either is used for electric power generation or for reducing the electric power requirements of a customer.

Reserve Capacity Generating capacity available to meet unanticipated demands for power, or to generate power in the event of outages in normal generating capacity. This includes delays in operations of new scheduled generation. Forced outage reserves apply to those reserves intended to replace power lost by accident or breakdown of equipment. Load growth reserves are those reserves intended for use as a cushion to meet unanticipated load growth.

Resource Extension The length of time that Westerns contracts may extend into the future.

Resource Pool Consists of uncommitted marketable resources that may originate from reducing allocations to customers, resource extension not accepted by customers, new resources, terminated contracts, or increases to existing marketable resources.

Sectors The economy is divided into four sectors for energy planning. These are the residential, commercial (e.g., retail stores, office, and institutional buildings), industrial, and irrigation sectors.

Simple-Cycle Combustion A combustion turbine is similar to a jet engine. Large volumes of air

Turbine (SCCT) are forced to high pressures in a compressor. Natural gas is injected and combustion occurs. The resulting high-temperature, high-pressure exhaust gases are expanded in a turbine which produces electricity.

Siting Agencies State agencies with the authority for issuing permits to locate generating plants of defined types and sizes to utilities at specific locations.

Siting and Licensing The process of preparing a power plant and associated services, such as transmission lines, for construction and operation. Steps include locating a site, developing the design, conducting a feasibility study, preliminary engineering, meeting applicable regulatory requirements, and obtaining the necessary licenses and permits for construction of the facilities.

Small Customers According to the Energy Policy Act of 1992, customers with total annual energy sales of usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility.

Supply Curve A traditional economic tool used to depict the amount of a product available across a range of prices.

Surcharge Under the Energy Policy Act of 1992, an additional sum added to the usual power rate charged to a Western customer. Surcharges can range from 10 percent to 30 percent of a customer's bill.

Thermal Resource A facility that produces electricity by using a heat engine to power an electric generator. The heat may be supplied by burning coal, oil, natural gas, biomass or other fuel, by nuclear fission, or by solar or geothermal sources.

TIER TIER is the times interest ratio which relates interest on long-term debt to patronage capital. The Rural Electrification Administration sets a minimum level for its borrowers.

ABBREVIATIONS

ADSMP = Association of Demand-Side Management Professionals
ASHRAE = American Society of Heating, Refrigerating, and Air Conditioning Engineers
BAO = Billings Area Office
Btu = British thermal unit
C&RE = Conservation and Renewable Energy
CFC = chlorofluorocarbon
CFR = Code of Federal Regulations
CO2 = carbon dioxide
co-op = cooperative
CPAM = Conservation Policy Analysis Model
CRSP = Colorado River Storage Project
CROD = Contract Rate of Delivery
CVP = Central Valley Project
CWP = Construction Work Plan
DOE = U.S. Department of Energy
DSC = debt service coverage
DSM = demand-side management
EIA = Energy Information Administration
EIS = environmental impact statement
EMP = Energy Management Plan
EPA = U.S. Environmental Protection Agency
EPRI = Electric Power Research Institute
FERC = Federal Energy Regulatory Commission
FR = Federal Register
G&AC = Guidelines and Acceptance Criteria
G&T = generation and transmission
GDP = Gross Domestic Product
GW = gigawatt
GWh = gigawatthour
HVAC = heating, ventilation, and air conditioning
IOU = investor-owned utility
IRP = integrated resource plan(ning)
kW = kilowatt
kWh = kilowatthour
LAO = Loveland Area Office
MBA = member-based association
MSA = metropolitan statistical area
MW = megawatt
MWh = megawatthour
NAAQS = National Ambient Air Quality Standards
NAPAP = National Acidic Precipitation Assessment Program
NARUC = National Association of Regulatory Utility Commissioners
NEPA = National Environmental Policy Act
NERC = North American Electric Reliability Council
NREL = National Renewable Energy Laboratory
NIOSH = National Institute of Occupational Safety & Health
NOx = oxides of nitrogen
PAO = Phoenix Area Office
PG&E = Pacific Gas and Electric Company
PM10 = particulate matter with a diameter of 10 microns or less
PMI = Power Marketing Initiative
POU = publicly owned utility
PRS = Power Requirements Study
PSC = public service commission
PUC = public utility commission
PUD = public utility district
RDF = refuse-derived fuel
Re-Act = Rural Electrification Act
REA = Rural Electrification Administration
RRIM = Resources and Rates Impact Model
RSP = respirable suspended particulates
SAO = Sacramento Area Office
SBS = sick building syndrome
SLCA/IP = Salt Lake City Area/Integrated Projects
SLCAO = Salt Lake City Area Office

CHAPTER 9 Index

APPENDIX A Environmental Effects of Air Emissions

Section A.1 of this appendix describes the major air emissions affecting ambient air quality. Section A.2 describes the pertinent regulations and factors affecting indoor air pollution.

A.1 AMBIENT AIR QUALITY

In accordance with the Clean Air Act (42 USC 7401-7626), the U.S. Environmental Protection Agency (EPA) established a list of six criteria pollutants: particulates, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, and lead. These are described in detail below. Descriptions of other emissions of concern - carbon dioxide (CO_2), hydrogen sulfide (H_2S), and volatile organic compounds (VOCs) - and a discussion of the amendments to the Clean Air Act are also provided.

A.1.1 Particulates

Particulates are fine solid particles that remain individually dispersed in gases and stack emissions. Total suspended particulates (TSP) refer to all particles found in the air and include pollutants from sources such as automobiles, agricultural lands, dirt roads, factories, and power plants. TSP can irritate the eyes, nose, and air passages; however, these irritations are likely to pass in one or two days with no permanent effects. Until 1987, the EPA regulated air concentrations of TSP. In 1987, the agency adopted a new PM_{10} standard that replaced the standard for TSP. PM_{10} refers to particulates with an aerodynamic diameter of 10 microns or less. Particulates of this size are small enough to be inhaled deeply into the lung. These smaller particles result in greater risks to human health because they can lodge in the lungs and irritate or damage sensitive lung tissue. Fine particles are frequently toxic and can carry with them harmful pollutants.

Particles from industrial and combustion sources contribute more significantly to health effects than do other sources such as soil (Ozkaynak and Thurston 1987). Asthmatics may be especially sensitive to the effects of particulates. In addition, particulates may contain radioactive elements that may cause cancer.

In addition to their health effects, particulates affect visibility. In 1977, Congress added Section 169A to the Clean Air Act to protect national parks and wilderness areas (Class 1 areas) from visibility impairment. Many researchers and government agencies have focused on visibility issues in national parks in the desert Southwest. The National Park Service (NPS) has identified haze as impacting scenic vistas in national parks and indicated that coal-fired electricity generating plants could contribute to visibility degradation (Balson and Hulse 1991; Farber et al. 1991; Malm et al. 1989; Mathai, Allen, and Giovanni 1986). However, assigning the cause of haze to a particular source is difficult (Pitchford and Shaver 1991; Chan and Bhardwaja 1991; Mathai, Allen, and Giovanni 1986).

Sulfuric acid and sulfate particles, formed in the atmosphere from SO_2, can scatter light, contributing to haze and impacts on visibility. The National Acidic Precipitation Assessment Program (NAPAP) concluded that sulfates are responsible for 30 percent of the reducible light extinction in the rural west and 15 percent in the urban west. NAPAP's estimates for oxides of nitrogen (NO_x) are 10 percent for the rural west and 25 percent for the urban west (NAPAP 1991, p. 121). Computer simulations demonstrate that visual range has been reduced 37 percent in the rural west, compared with 82 percent to 91 percent in the rural east, urban east, and urban west (NAPAP 1991, p. 121).

In Section 169B, the 1990 amendments to the Clean Air Act direct the EPA, the NPS, and other federal agencies to gather information about the need for expansion of visibility protection. Section 169B also established a Grand Canyon Visibility Transport Commission to assess the pollutants that cross state boundaries that may affect visibility at Grand Canyon National Park. Similar commissions may be established to address visibility problems in other Class 1 areas. One of the goals of the information gathering and the commissions is to identify clean air corridors, which deliver clean air to Class 1 areas. The commissions will consider how alternate siting and controls may be used in the corridors to protect visibility. New regulations for these corridors could affect the operation and siting of combustion power plants many miles away from Class 1 areas experiencing visibility degradation.

A.1.2 Sulfur Dioxide

Sulfur compounds are key in the formation of smog and acid rain. Sulfur dioxide can penetrate deep into the lung as a respirable particulate, causing symptoms similar to allergic reactions or viral respiratory infections. Sulfur dioxide quickly affects the airways in the lung to restrict airflow, resulting in shortness of breath, coughing, and increased secretions. Long-term exposure causes chronic bronchitis and may contribute to asthma. Asthmatics and people with sensitive airways may be at greatest risk.

Spinach, lettuce, and alfalfa are among the plants most sensitive to damage from SO_2. The gas is suspected in the acidification of lakes and can corrode building materials, destroy paint pigments, erode statues, and harm textiles. Sulfur compounds and NO_x can combine in the air with water to form acid rain or snow, or may be directly deposited to adversely affect water resources, plant and animal life, and surface materials. Western sites that are vulnerable to acidic deposition include the Sierra Nevada Mountains east of San Francisco, the San Francisco air basin, the Los Angeles air basin, southeastern Arizona, and central Colorado (NAPAP 1991).

The combustion of high-sulfur coal is the major source of SO_2 nationwide. However, low-sulfur coal is readily available in the western United States. Title IV of the Clean Air Act Amendments of 1990 aims to reduce emissions of SO_2 and NO_x because of their contribution to the formation of acid precipitation. The program goals are to reduce SO_2 emissions by 10 million tons per year, about a 50-percent reduction from 1980 levels, and NO_x by two million tons per year (Schorr and Yates 1991).

To meet the SO_2 goals, the amendments established a market-based approach in which plant operators use tradable "allowances" to decide how to control emissions (Schorr and Yates 1991; Moyer and Francis 1991). The allowances may be purchased as a commodity. Each allowance allows the emission of one ton of SO_2. After January 1, 2000, all utility power plants must have a SO_2 allowance for each ton emitted. Thus, if a plant is emitting too much SO_2, operators may install pollution control equipment, switch to lower sulfur fuels, or acquire additional allowances. Allowances may be held for future expansion or sold on the commodities market.

The number of allowances granted to the owner of a unit will be based on the average fuel consumption in million Btus (mmBtu) for the years 1985 through 1987 multiplied by the target average SO_2 emission rates of 2.5 pounds per mmBtu (phase 1) or 1.2 pounds per mmBtu (in phase 2).

Coal plants that emit SO_2 at a rate below 1.2 pounds/mmBtu will be able to increase emissions by 20 percent between the baseline year and the year 2000 (Moyer et al. 1993, pp. 4-2). Plants that produce less than 1.2 pounds/mmBtu during 1985 will be awarded emission credits at the rate of their actual or allowable 1985 emission rate, plus 20 percent, not to exceed 1.2. Plants emitting less than 0.60 pounds/mmBtu have even more stringent requirements. Thus, after phase 2 begins in the year 2000, the S02 emission rate used to award allowances may be less than 1.2 pounds/mmBtu for plants that are cleaner than the target rate (Clean Air Act, Section 405(d), 42 USC 7651d). However, operators may purchase or collect allowances to emit quantities of SO_2 greater than the target rate.

One provision of the amendments allows the EPA to allocate a reserve of 300,000 allowances to utilities taking conservation and renewable energy measures between December 31, 1991, and December 31, 2000. The plant operator must demonstrate that conservation or renewable energy sources offset SO_2 emissions.

A.1.3 Oxides of Nitrogen

Nitrogen dioxide forms during the high temperatures of combustion. At high concentrations, NO_2 is reddish brown and toxic. The gas irritates mucous membranes and causes coughing, headache, and shortness of breath. It is a key ingredient in the formation of smog and acid rain and can react with moisture in the air to form nitric acid, which is highly corrosive to metals. Nitrogen dioxide is also toxic to vegetation at high concentrations.

Nitrogen dioxide, nitric oxide (NO), and other oxides of nitrogen are commonly referred to as NO_x. Nitric oxide is formed in auto exhaust and most industrial combustion sources. In the presence of ozone, NO rapidly reacts to form NO_2.

Nitrous oxide (N20) is not often associated with electricity generation. However, Swedish measurements indicate that coal-fired atmospheric fluidized bed combustion processes may emit significant quantities of N_2O. Scientists are concerned about N_2O because it contributes to both global warming and ozone depletion (Bradley, Watts, and Williams 1991).

The only urban center in the nation exceeding federal NO_2 air quality standards is Los Angeles. Personal exposure to NO_2 may be dominated by indoor exposure. However, as one of the ingredients (precursors) that go into making ozone, NO_2 has come under increased regulation under the 1990 amendments to the Clean Air Act. Under the amendments, NO_2 is to be treated as a nonattainment pollutant in ozone nonattainment areas (Schorr and Yates 1991).

To achieve the acid rain reduction target of two million tons per year in NO_x emissions that is stipulated in the Clean Air Act amendments of 1990, low-NO_x burners must be installed in existing utility burners. Compliance may be required by January 1, 1995.

A.1.4 Carbon Monoxide

Carbon monoxide, a colorless, odorless gas, is the product of incomplete combustion when natural gas, oil, wood, coal, or other materials are burned. Carbon monoxide increases when there is an inadequate supply of combustion air. The best means of controlling CO emissions is a properly designed and operated combustion process.

Carbon monoxide interferes with the delivery of oxygen throughout the body. Mild oxygen deficiencies can affect vision and brain function. Exposure to high levels can cause headaches, irregular heartbeat, nausea, weakness, confusion, and death. Carbon monoxide inhaled by pregnant women may threaten the unborn child's growth and mental development.

Automobiles are a primary source of CO. Thus, nonattainment areas tend to be located in business districts and at busy intersections where automobile traffic is heavy.

A.1.5 Atmospheric Ozone

Ozone is a pungent, toxic, highly reactive form of oxygen. It can irritate the nose, throat, and lungs. Exposure to ozone can cause increased airway resistance and decreased efficiency of the respiratory system. In people exercising and in those with respiratory disease, ozone can cause sore throat, chest pain, coughing, and headaches. Ozone can cause reductions in plant growth and crop yields. Ozone can also result in the fading of paint and fabric and the accelerated aging and cracking of synthetic rubbers.

Ozone is not emitted directly to the air. It forms through a series of photochemical reactions that involve sunshine, other pollutants - most notably NOx and VOCs (hydrocarbons) - and oxygen.

Ozone concentrations tend to be related to VOC emissions from automobile exhausts and nitrogen oxides from other sources, and the amount of sunshine available. Thus, areas violating the standard tend to be in cities with high automobile use and abundant sunshine.

Ozone has contributed to the decline of ponderosa and Jeffrey pines in the San Bernardino Mountains east of Los Angeles and the central Sierra Nevada Mountains of California (NAPAP 1991, p. 53; Miller et al. 1989). The impacts in California's coniferous forest range from slight to severe (NAPAP 1991, p. 53). Areas with damaged forests include Yosemite, Sequoia, and King Canyon national parks, and Lake Tahoe (Pedersen 1989; Duriscoe and Stolte 1989; Peterson, Arbaugh, and Robinson 1989). The range of yield reduction that ozone may cause in commercial crops is 2 percent to 56 percent, at ambient levels (NAPAP 1991, p. 55).

A.1.6 Lead

The American Lung Association (1989) notes that airborne lead occurs in particulate form in a variety of hazardous chemical compounds. Lead compounds added to gasoline are a primary source of lead ambient air pollution. As leaded gasoline is phased out, ambient concentrations are dropping. Industries that produce or utilize lead, such as smelters and battery producers, are important stationary sources. Lead accumulates in bones and teeth, so repeated small exposures may produce a toxic effect. According to epidemiological studies, lead may impede mental functioning, interfere with synthesis of blood hemoglobin, or raise blood pressure. It is possible that these effects may occur at concentrations found in typical urban areas. Lead is not typically associated with power plants, unless contaminated fuel is used in the facilities, for example, in a solid waste combustor.

A.1.7 Carbon Dioxide and Other Greenhouse Gases

Although not listed as a criteria pollutant, CO_2 is a gas associated with the widespread use of fossil fuels such as coal, oil, and natural gas. Industrial processes and deforestation also contribute to increasing CO_2 levels. Growing concentrations of CO_2 in the atmosphere may cause global climate change because of CO_2's ability to trap heat in the earth's atmosphere. Methane, N_2O, and chlorofluorocarbons (CFCs) are other gases that may contribute to the greenhouse effect.

Many researchers believe the buildup of these gases, referred to as greenhouse gases because they trap heat much like the panes of glass in a greenhouse, may cause the earth's average temperature to rise as much as 2 to 4 C in the next 50 years. This warming of the climate may contribute to many environmental problems, such as reduced agricultural production in drought-stricken areas, increases in ocean levels by as much as 50 feet, shoreline flooding from thermal expansion and glacial melting, and dramatic shifts in local ecological systems.

The U.S Congress Office of Technology Assessment (OTA 1991) reports that in industrialized countries, greenhouse gas emissions are primarily related to energy use. With 20 percent of the world's population, these countries account for 75 percent of annual energy use. Utility fossil fuel consumption accounts for about 40 percent of the carbon emissions in the United States (Bradley, Watts, and Williams 1991, p. 1.2). Of this contribution, about 80 percent is from coal combustion, 12 percent from natural gas, and 7 percent from oil (Bradley, Watts, and Williams 1991).

Actual impacts of increased atmospheric CO_2 levels are difficult to predict. Model results vary substantially, and local results are the most difficult to determine. Agricultural productivity is likely to be sensitive to global climate change. Adams et al. (1990) suggest that results will depend on the severity of the change and the compensating effects of increased CO_2 on crop yields. Analyses by Adams and others (Curry et al. 1990) suggest that irrigated acreage is likely to increase and regional agricultural patterns will shift.

Many researchers have found increased exposure to atmospheric CO_2 to increase plant productivity by as much as 30 percent (Acock and Allen 1985; Allen et al. 1988; EPA 1989). However, global climate change will result in a complex set of interactions.

Increased CO_2 alone may be beneficial to crops; however, increased temperatures and reduced rainfall could severely reduce production (Allen 1989a; 1991). A mean warming of 1 C could extend the growing season by 10 days, but cause more frequent droughts because of reduced precipitation and increased evaporation (Waggoner 1983; Rosenzweig 1990). The effects of other emissions, such as ozone, SO_2, and NO_x, may be reduced by increased CO_2 levels (Allen 1989b). Other researchers suggest that fundamental ecological degradation could overshadow potential benefits of increased CO_2 (Bazzaz and Fajer 1992).

Ozone in the upper atmosphere (the stratosphere) absorbs radiation from the sun. When ozone is diminished, increased ultraviolet radiation may strike the earth's surface, which is likely to increase human skin cancer rates and stunt plant growth. The EPA has estimated that each 1 percent drop in ozone is projected to result in 4 percent to 6 percent more cases of the most common types of skin cancer (EPA 1987 as reported in Brown et al. 1989, p. 82). Increased radiation penetrating the stratosphere is also likely to contribute to global warming. Chlorofluorocarbons are a key pollutant that destroys stratospheric ozone. Sources of this pollutant type related to electrical utilities are heat transfer fluids used in air conditioning and heating equipment and gases used to make some types of rigid foam insulation (Marseille and Baechler 1990).

A.1.8 Hydrogen Sulfide

A key source of H_2S is geothermal electricity generation. Although steam composition varies widely among geothermal fields, CO_2 is the major noncondensible gas component of steam. Hydrogen sulfide is the second or third most noncondensible gas by weight (Weres 1988). In small concentrations this noxious gas has an unpleasant odor but is harmless. But at strong concentrations, the gas paralyzes the olfactory nerves and becomes odorless. Thus, when H_2S is present in lethal quantities it gives no warning. The gas can accumulate in low-lying pockets. Without abatement, sulfur emissions from some geothermal sites are comparable to those from coal-fired power plants (Weres 1988). Hydrogen sulfide is ultimately converted to sulfate particulates and sulfuric acid in the atmosphere. Thus, H_2S has immediate local impacts, as well as potential regional effects.

California air quality standards limit H_2S concentrations to 0.03 parts per million (ppm) over a one-hour averaging time (California 1991). Under Title III (Hazardous Air Pollutants) of the 1990 amendments to the Clean Air Act, the EPA assessed the public health and environmental hazards of H_2S emissions from oil and natural gas extraction (EPA 1993).

A.1.9 Volatile Organic Compounds

One group of VOCs, hydrocarbons, are currently regulated as precursors to ozone formation or as pollutants hazardous to human health. A key source of hydrocarbons is gasoline, both the emissions resulting from combustion and those released during refueling. In Los Angeles, a "clean fuels" program has been established to encourage alternative fuel types in fleet vehicles. The Clean Air Act Amendments established a California Pilot Program to encourage and demonstrate the production of clean fuels and vehicles (Wilson 1991). In 1996, auto companies must sell 150,000 cars in California that have emission levels one-half that allowed for other cars. This number grows to 300,000 in 1999. In 2001, emission levels are again reduced by half.

Indoor VOC exposure is often several times greater than outdoor exposure. Indoor sources include building materials, furnishings, cleansers, and consumer products. Additional information on indoor air quality is in Chapter 3, Section 3.2.2.

A.1.10 Hazardous Air Pollutants

Title III of the Clean Air Act Amendments overhauled the hazardous air emission program (Moyer and Francis 1991). The new amendments shift the focus of regulation from a pollutant-by-pollutant approach to technology-based regulation of source categories. The new law lists 189 toxic air pollutants. Typically these pollutants are carcinogens, mutagens (substances that can cause gene mutations), or reproductive toxins (Wegman 1991). Title III directs the EPA to perform three studies about emissions from electric utility steam generating units. The three studies will address the following areas (Moyer and Francis 1991):

* the hazards to public health reasonably anticipated from listed hazardous air pollutants from electric utility steam generating units
* mercury emissions from electric utility steam generating units, municipal waste combustion units, and area sources
* a study by the National Institute of Environmental Health Science to determine the threshold level of mercury exposure below which no adverse health risks are expected.

A.2 INDOOR AIR QUALITY

This section discusses many of the factors affecting indoor air quality and describes potential impacts that may result from indoor air pollutants. Much of this discussion and the information in the descriptions below is taken from Baechler, Hadley, and Marseille (1990).

A.2.1 Ventilation

The exchange of air in buildings with fresh outside air is the result of the combination of infiltration, natural ventilation, and mechanical ventilation. Even in new buildings, infiltration can be a significant contributor to total building air exchange rates. This is particularly true in winter when temperature and pressure difference, the driving forces for infiltration, are greatest and mechanical systems are operated with a minimum of outside air. Infiltration is the flow of air through cracks and unintentional openings in the building envelope.

Natural ventilation is under the manual control of building occupants and is due to operable windows, doors, skylights, roof ventilators, stacks, and other planned inlet and outlet openings. It can be classified as "controlled" infiltration/exfiltration. Natural ventilation is more likely to occur during periods of moderate to warm outdoor weather conditions.

The quantity of air flowing through openings, either unintentional or planned, depends on both the dynamic pressure of the wind and buoyancy forces resulting from indoor/outdoor temperature differences.

Mechanical ventilation is the forced movement of air by fans into and out of a building. The primary purpose of the mechanical ventilation system is to provide a healthy and comfortable indoor environment for building occupants. Other purposes include temperature and humidity control, improved thermal comfort, air exchange control, and exhausting of smoke, waste heat, and toxic pollutants. Mechanical ventilation may serve an entire building, or it may move air in a local environment, such as over a cook stove or work bench, or in a restroom or smoking area.

When fresh air input rates for a building are restricted, either intentionally or inadvertently, concentrations of indoor air contaminants will increase. One national survey reports that 25 percent of American workers feel that the quality of their workplace air affects their work adversely (Sheldon et al. 1988a). This is known as Sick Building Syndrome (SBS), which refers to health and comfort problems associated with working or being in a particular building (EPA 1988).

Increasing minimum ventilation rates has been one response to this problem. However, recent studies indicate that there is poor correlation between ventilation rates and pollution levels. In an investigation into 38 commercial buildings in the Pacific Northwest, the correlation between ventilation rates and pollutant levels was weak (Turk et al. 1987). However, this was at least in part attributed to the low pollutant levels observed. The same conclusion may not be true for other buildings, particularly those with higher levels of contamination.

Skov and Valbjorn (1987) and Valbjorn and Skov (1987) found no association between SBS and ventilation characteristics, but did find strong positive correlations between SBS and building age, total weight, potential allergenic portion of floor dust, area of fleecy material, open shelving per cubic meter of air, and air temperature.

Field studies suggest that ventilation rates often exceed the standards set by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) listed in ASHRAE 62-1981 (ASHRAE 1981) and ASHRAE 62-1989 (ASHRAE 1989) (see Table A.1). Seton, Johnson & Odell (1984) conclude that nominal ventilation rates based on actual occupancy are significantly higher than the design rates listed in ASHRAE 62-1981, "Ventilation for Acceptable Indoor Air Quality." Turk (et al. 1987) found that in a sample of 40 buildings, on average, the ventilation rates ranged from 2 to 8 times the rates recommended for smoking areas in ASHRAE 62-1981 (ASHRAE 1981). The ventilation rates contained in Standard 62-1981 for smoking areas (as opposed to the ventilation rates listed for nonsmoking areas) are greater than the single ventilation rates listed in the newer ASHRAE Standard, 62-1989. (ASHRAE 62-1989 listed one set of rates instead of separate rates for smoking and nonsmoking areas.) Thus, Turk's findings suggest that in existing buildings, ventilation rates exceed both the new ASHRAE Standard 62-1989 and the old ASHRAE Standard 62-1981. If the ventilation rates are reduced to match either of the standards, indoor pollution concentrations are likely to increase, although the standards are designed to ensure adequate ventilation levels.

A.2.2 Volatile Organic Compounds

VOCs are carbon-based chemicals that evaporate easily and give off vapors that can be inhaled. The explosion of new building materials, consumer goods, and office equipment developed since World War II, has made VOC sources ubiquitous. Wallace (1987) has concluded that nearly every home and business contains common materials that may cause elevated levels of toxic chemical exposure. More than 900 separate VOCs have been found in indoor air.

The levels of individual VOCs found in buildings are often several times below threshold limit values for occupational settings, or levels considered to be harmful for any one chemical in an occupational setting. However, many indoor VOC concentrations have been found to be much higher than levels found outdoors. Sheldon et al. (1988a) found indoor-outdoor ratios of total organics of 2 or 3 to 1 in three older buildings. In a new office building this ratio was 50 to 1, dropping to 10 to 1 after two months, and 5 to 1 after three additional months. A total of about 500 compounds were found at least once from all of the buildings sampled.

In a companion study, Sheldon et al. (1988b) found indoor levels of total organics in two new buildings up to 400 times greater than outdoor concentrations. After several months these concentrations dropped to 3 to 30 times outdoor levels.

Building materials, such as caulks and insulation associated with energy-efficiency measures, have been found to emit VOCs. However, an environmental assessment (EA) prepared for the U.S. Department of Energy (DOE 1986) concluded that emissions from five insulation types did not contribute significantly to indoor VOC concentrations. This conclusion was based on mass-balance calculations using emission rates from chamber study tests of building materials. Emissions from fibrous insulation may be related to how moist the material is (Van der Wal et al. 1987).

For wet materials, such as caulk, Tichenor and Mason (1988) have concluded that time, or the age of the sample, is critical to overall concentrations; source durations can be as short as a few hours. Emission rates decrease rapidly with time as the VOCs are depleted from the silicone caulk source. The emission rates are initially higher with a high air exchange rate, but after two hours the emission rates are higher for the low air exchange rate.

%TABLE A.1. Recommended Airflow Rates (cfm/person) Contained in ASHRAE

A.2.3 Respirable Suspended Particulates

Respirable suspended particulates (RSPs) are particles or fibers in the air that are small enough to be inhaled. They are a broad class of chemically and physically diverse substances that can occur in a solid or liquid phase, or in combination. Particulates in the ambient air are regulated under the National Ambient Air Quality Standards (NAAQS) as PM10 which refers to particulate matter measuring less than 10 micrometers in diameter.

RSPs are generated from building materials (fiberglass, cellulose, or asbestos fibers), combustion devices (gas appliances, gas hot water heaters and boilers), occupant activities (tobacco smoke, resuspended dust), and infiltration from outdoor sources (atmospheric dust, combustion emissions from mobile and stationary sources). However, the largest single source of RSP in the indoor environment is tobacco smoke (Turk et al. 1987).

Asbestos is a collective term for a variety of asbestiform minerals that satisfy a particular industrial-commercial need. Chrysotile accounts for over 95 percent of the asbestos sold in the United States (Godish 1989). Asbestos fibers are characterized by their small diameter, high length-to-width ratio, and great strength and flexibility. Scientist have hypothesized that fibers from fiber glass and mineral wool insulation may cause cancer in the same way as asbestos. Fiberglass fibers have different dimensions than asbestos, and as yet, there is no proven link with cancer (WHO 1987).

Application of unbound asbestos has been banned by regulatory action. Therefore, owners and builders of new buildings do not need to be concerned about friable asbestos.

The installation of insulation in the walls, ceiling, roof, foundation or slab of a buildings can directly increase the levels of RSP/fibers by increasing the amount of fiberglass/cellulose material in the building. Fiberglass RSP can also come from the insulation used in ventilation ducting. Gamboa, Gallagher, and Mathews (1988) found that levels of fiberglass fibers released from Type 475 duct board and fiberglass duct liner were typically well below the 3.0 fibers/cm3 permissible exposure limit proposed in 1977 by the National Institute of Occupational Safety and Health (NIOSH). However, these releases still resulted in fiber levels approximately twice normal background concentrations. The installation of these measures in buildings is likely to amount to only a negligible risk for occupants. However, installers of the measures may have significant exposure (Baechler 1989; Du Pont and Morrill 1989, p. 134).

Conservation measures that require the disruption of asbestos sources may result in exposure to this pollutant. Disruption may result from the replacement of hydronic pipe insulation, duct insulation, heating system improvement, or blown-in wall insulation. However, if asbestos sources are present in a building, they may ultimately require removal. Therefore, if conservation activities locate these sources, and they are properly removed and disposed of, an environmental benefit may result.

A.2.4 Biological Contaminants

Biological contaminants are particles of biological origin, including such diverse entities as bacteria, fungi, viruses, amoebae, algae, and pollen grains. Also included are plant parts; insect parts and wastes; animal saliva, urine, and dander; human dander; and a variety of organic dusts (Godish 1989). The two most important allergen contaminants found in indoor air that are known to cause both allergies and asthma are dust mites and fungi (Godish 1989).

Virtually any substrate that includes a carbon source and water will support the growth of some microorganism. Many buildings with biological contamination can trace the probable cause to the lack of proper maintenance of the heating, ventilation, and air conditioning (HVAC) system. Typical maintenance problems include condensate drains and drip pans that are not cleaned, filters that are not cleaned or replaced, and dirt and biological growth in the duct system. The most severe indoor biological pollution problems result from growth of offending organisms on surfaces within structures.

Conservation measures that increase the level of moisture in a building or in specific HVAC equipment may contribute to biological contamination. However, the inspections that often precede conservation measure installation may help to identify and clean up potential sources.

A.2.5 Radon

Radon is an inert, radioactive gas that occurs naturally in the environment as a decay product of radium. It, in turn, decays to form radioactive progeny that may attach to dust particles or remain unattached. If these progeny are inhaled, they can be drawn into the lungs, where they emit alpha energy which may lead to lung cancer.

Ambient concentrations of radon are generally quite low due to dilution with large volumes of outdoor air. Indoor concentrations can be much greater than outdoor levels. The amount or radon found in the indoor environment is affected by the radium content and porosity of the adjacent soil, building construction type and materials, and meteorological conditions.

Some researchers and government agencies have concluded that radon levels in homes are source dominated, and that indoor concentrations have little to do with building ventilation rates or conservation measures to reduce infiltration (Turk et al. 1988; Thor 1988; Harris 1987; Doyle, Nazaroff, and Nero 1984; Nero et al. 1983). However, one study has found a correlation between tightening measures and increased radon levels (Nagda, Koontz, and Rector 1985). Turk et al. (1988, p. 1) suggest that this study may have limited applicability to other building types and geographic regions. Turk further suggests that weatherization measures in homes may reduce radon entry rates (Turk et al. p. 64). The evidence for this reduction is not conclusive, but the reasoning is that tightening measures reduce radon entry points and reduce buoyancy forces. Buoyancy forces are caused by differences in indoor and outdoor temperature; these forces can increase radon entry into homes.

A.2.6 Combustion Gases

Combustion gases, such as CO, CO2, NO, NO2, and SO2 can be introduced into the indoor environment by a variety of indoor and outdoor sources. Smoking of tobacco products indoors is the major source of combustion-generated contaminates found in indoor air (Godish 1989). More than 2,000 gaseous compounds have been identified in cigarette smoke (DOE 1986). Other sources include wood-burning stoves and fireplaces, gas-fired cook stoves, heaters, and water heaters; and kerosene-burning space heaters.

Electricity conservation measures are likely to have little effect on sources of combustion gases and peak pollutant concentrations. However, measures that dampen the effects of weather on indoor comfort may limit the use of sources that are related to changes in temperature, such as kerosene heaters or woodstoves. Measures that reduce ventilation rates will increase the period of time that pollutants remain indoors. The primary source of CO in buildings is attached parking garages. Indoor levels of CO can be reduced by installing CO-controlled, garage ventilation systems. Installation of local ventilation, such as vortex hoods in the kitchen areas of restaurants, will reduce levels of contaminants from gas stoves by effectively removing the contaminants at the source.

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APPENDIX C Extract of Public Law

EXTRACT OF PUBLIC LAW 102-486

THE ENERGY POLICY ACT OF 1992

SEC. 114. AMENDMENT OF HOOVER POWER PLANT ACT.

Title II of the Hoover Power Plant Act of 1984 (42 U.S.C. 7275-7276, Public Law 98-381) is amended to read as follows:

"TITLE II--INTEGRATED RESOURCE PLANNING

"SEC. 201. DEFINITIONS.

"As used in this title:

"(1) The term 'Administrator' means the Administrator of Western Area Power administration.

"(2) The term 'integrated resource planning' means a planning process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

"(3) The term 'least cost option' means an option for providing reliable electric services to electric customers which will, to the extent practicable, minimize life- cycle system costs, including adverse environmental effects, of providing such service. To the extent practicable, energy efficiency and renewable resources maybe given priority in any least-cost option.

"(4) The term 'long-term firm power service contract' means any contract for the sale by Western Area Power Administration of firm capacity, with or without energy, which is to be delivered over a period of more than one year.

"(5) The term `customer' or 'customers' means any entity or entities purchasing firm capacity with or without energy, from the Western Area Power Administration under a long-term firm power service contract. Such terms include parent-type entities and their distribution or user members.

"(6) For any customer, the term 'applicable integrated resource plan' means the integrated resource plan approved by the Administrator under this title for that customer.

"SEC. 202. REGULATIONS TO REQUIRE INTEGRATED RESOURCE PLANNING "(a) REGULATIONS.--Within 1 year after the enactment of this section, the Administrator shall, by regulation, revise the Final Amended Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs published in the Federal Register on August 21, 1985 (50 F.R. 33892), or any subsequent amendments thereto, to require each customer purchasing electric energy under a long-term firm power service contract with the Western Area Power Administration to implement within 3 years after the enactment of this section, integrated resource planning in accordance with the requirements of this title.

"(b) CERTAIN SMALL CUSTOMERS.--Notwithstanding subsection (a), for customers with total annual energy sales or usage of 25 Gigawatt Hours or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility, the Administrator may establish different regulations and apply such regulations to customers that the Administrator finds have limited economic, managerial, and resource capability to conduct integrated resource planning. The regulations under this subsection shall require such customers to consider all reasonable opportunities to meet their future energy service requirements using demand-side techniques, new renewable resources and other programs that will provide retail customers with electricity at the lowest possible cost, and minimize, to the extent practicable, adverse environmental effects.

"SEC. 203. TECHNICAL ASSISTANCE.

"The Administrator may provide technical assistance to customers to, among other things, conduct integrated resource planning, implement applicable integrated resource plans, and otherwise comply with the requirements of this title. Technical assistance may include publications, workshops, conferences, one-to-one assistance, equipment loans, technology and resource assessment studies, marketing studies, and other mechanisms to transfer information on energy efficiency and renewable options and programs to customers. The Administrator shall give priority to providing technical assistance to customers that have limited capability to conduct integrated resource planning.

"SEC. 204. INTEGRATED RESOURCE PLANS.

"(a) REVIEW BY WESTERN AREA POWER ADMINISTRATION.--Within 1 year after the enactment of this section, the Administrator shall, by regulation, revise the Final Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs published in the Federal Register on August 21, 1985 (50 F.R. 33892), or any subsequent amendments thereto, to require each customer to submit an integrated resource plan to the Administrator within 12 months after such regulations are amended. The regulation shall require a revision of such plan to be submitted every 5 years after the initial submission. The Administrator shall review the initial plan in accordance with a schedule established by the Administrator (which schedule will provide for the review of all initial plans within 24 months after such regulations are amended), and each revision thereof within 120 days after his receipt of the plan of revision and determine whether the customer has in the development of the plan of revision, complied with this title. Plan amendments may be submitted to the Administrator at any time and the Administrator shall review each such amendment within 120 days after receipt thereof to determine whether the customer in amending its plan has complied with this title. If the Administrator determines that the customer, in developing its plan, revision, or amendment, has not complied with the requirements of this title, the customer shall resubmit the plan at any time thereafter. Whenever a plan or revision or amendment is resubmitted the Administrator shall review the plan or revision or amendment within 120 days to determine whether the customer has complied with this title.

"(b) CRITERIA FOR APPROVAL OF INTEGRATED RESOURCE PLANS
The Administrator shall approve an integrated resource plan submitted as required under subsection (a) if, in developing the plan, the customer has:

"(1) Identified and accurately compared all practicable energy efficiency and energy supply resource options available to the customer.

"(2) Included a 2-year action plan and a 5-year action plan which will describe specific actions the customer will take to implement its integrated resource plan.

"(3) Designated least-cost options to be utilized by the customer for the purpose of providing reliable electric service to its retail consumers and explained the reasons why such options were selected.

"(4) To the extent practicable, minimized adverse environmental effects of new resource acquisitions.

"(5) In preparation and development of the plan (and each revision or amendment of the plan) has provided for full public participation, including participation by governing boards.

"(6) Included load forecasting.

"(7) Provided methods of validating predicted performance in order to determine whether objectives in the plan are being met.

"(8) Met such other criteria as the Administrator shall require.

"(c) USE OF OTHER INTEGRATED RESOURCE PLANS.--Where a customer or group of customers are implementing integrated resource planning under a program responding to Federal, State, or other initiatives, including integrated resource planning considered and implemented pursuant to section 111 (d) of the Public Utility Regulatory Policies Act of 1978, in evaluating that customer's integrated resource plan under this title, the Administrator shall accept such plan as fulfillment of the requirements of this title to the extent such plan substantially complies with the requirements of this title.

"(d) COMPLIANCE WITH INTEGRATED RESOURCE PLANS--Within 1 year after the enactment of this section, the Administrator shall, by regulation, revise the Final Amended Guidelines and Acceptance Criteria for Customer Conservation and Renewable Energy Programs published in the Federal Register on August 21, 1985 (50 F.R. 33892), or any subsequent amendments thereto, to require each customer to fully comply with the applicable integrated resource plan and submit an annual report to the Administrator (in such form and containing such information as the Administrator may require) describing the customer's progress to the goals established in such plan. After initial review under subsection (a) the Administrator shall periodically conduct reviews of a representative sample of applicable integrated resource plans and the customer's implementation of the applicable integrated resource plan to determine if the customers are in compliance with their plans. If the Administrator finds a customer out-of-compliance, the Administrator shall impose a surcharge under this section on all electric energy purchased by the customer from the Western Area Power Administration or reduce such customer's power allocation by 10 percent, unless the Administrator finds that a good faith effort has been made to comply with the approved plan.

"(e) ENFORCEMENT.--

"(1) NO APPROVED PLAN.If an integrated resource plan for any customer is not submitted before the date 12 months after the guidelines are amended as required under this section or if the plan is disapproved by the Administrator and a revised plan is not resubmitted by the date 9 months after the date of such disapproval, the Administrator shall impose a surcharge of 10 percent of the purchase price on all power obtained by that customer from the Western Area Power Administration after such date. The surcharge shall remain in effect until an integrated resource plan is approved for that customer. If the plan is not submitted for more than one year after the required date, the surcharge shall increase to 20 percent for the second year (or any portion thereof prior to approval of the plan) and to 30 percent thereafter until the plan is submitted of the contract for the purchase of power by such customer from the Western Area Power Administration terminates.

"(2) FAILURE TO COMPLY WITH APPROVED PLAN.--After approval by the Administrator of an applicable integrated resource plan for any customer, the Administrator shall impose a 10 percent surcharge on all power purchased by such customer from the Western Area Power Administration whenever the Administrator determines that such customer's activities are not consistent with the applicable integrated resource plan. The surcharge shall remain in effect until the Administrator determines that the customer's activities are consistent with the applicable integrated resource plan. The surcharge shall be increased to 20 percent if the customer's activities are out of compliance for more than one year and to 30 percent after more than 2 years, except that no surcharge shall be imposed if the customer demonstrates, to the satisfaction of the Administrator, that a good faith effort had been made to comply with the approved plan.

"(3) REDUCTION IN POWER ALLOCATION.--In the case of any customer subject to a surcharge under paragraph (1) or (2), in lieu of imposing such surcharge the Administrator may reduce such customer's power allocation from the Western Area Power Administration by 10 percent. The Administrator shall provide by regulation the terms and conditions under which a power allocation terminated under this subsection may be reinstated.

"(f) INTEGRATED RESOURCE PLANNING COOPERATIVES.--With the approval of the Administrator, customers within any State or region may form integrated resource planning cooperatives for the purposes of complying with this title, and such customers shall be allowed an additional 6 months to submit an initial integrated resource plan to the Administrator.

"(g) CUSTOMERS WITH MORE THAN 1 CONTRACT.--If more than one long-term firm power service contract exists between the Administrator and a customer, only one integrated resource plan shall be required for that customer under this title.

"(h) PROGRAM REVIEW.--Within 1 year after January 1, 1999, and at appropriate intervals thereafter, the Administrator shall initiate a public process to review the program established by this section. The Administrator is authorized at that time to revise the criteria set forth in section 204(b) to reflect changes, if any, in technology, needs, or other developments.

SEC. 205. MISCELLANEOUS PROVISIONS.

"(a) ENVIRONMENTAL IMPACT STATEMENT.--The provisions of the National Environmental Policy Act of 1969 shall apply to actions of the Administrator implementing this title in the same manner and to the same extent as such provisions apply to other major Federal actions significantly affecting the quality of the human environment.

"(b) ANNUAL REPORTS.--The Administrator shall include in the annual report submitted by the Western Area Power Administration (1) a description of the activities undertaken by the Administrator and by customers under this title and (2) an estimate of the energy savings and renewable resource benefits achieved as a result of such activities.

"(c) STATE REGULATED INVESTOR-OWNED UTILITIES.--Any State regulated electric utility (as defined in section 3(18) of the Public Utilities Regulatory Policies Act of 1978) shall be exempt from the provisions of this title.

"(d) RURAL ELECTRIFICATION ADMINISTRATION REQUIREMENTS.--Nothing in this title shall require a customer to take any action inconsistent with a requirement imposed by the Rural Electrification Administration."

H. Report 102-1018

Conference Committee report extract

"Sec. 114. Amendment of Hoover Power Plant Act.

"Section 114 would amend the Hoover Power Plant act of 1984 to require the Western Area Power Administration to issue rules requiring all but its smallest customers to engage in integrated resource planning. The Conferees recognize the efforts that many customers have already undertaken with respect to IRP. The conferees further recognize that these customers vary in size and capability to plan, and therefore intend that regulations be flexible enough to allow for reasonable variations in compliance requirements.

"In section 204(b) of such Act, as amended by this section, the customer is required, in preparation and development of the IRP, to provide for full public participation, including participation of governing boards. This language reflects the sound policy that better decisions result when the affected customers are involved in the resource planning process. Preference entities serve the public and are accountable to their consumers. By allowing the consumer to participate in the IRP preparation and development process, recognition of the public interest is assured.

"Section 204(c), as amended, would direct the Administrator to accept integrated resource plans that are currently being implemented by customers under other programs as fulfilling the requirements of this provision "to the extent such plan substantially complies with requirements of this title." The Conferees intend for the Administrator to be flexible in determining what satisfies the "substantial compliance" standard. IRP plans take significant resources to plan and implement.

"Finally, it is not the Conferees' intent that WAPA force changes in customers' approved IRP plans. WAPA should accept good faith efforts to comply with approved plans as generally satisfying compliance standards."

APPENDIX D Social and Economic Statistics

The Western Area Power Administration's service territory covers portions of 15 western states. The service territory is divided into five marketing areas with area offices located in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; Sacramento, California; and Salt Lake City, Utah. Population profiles based on 1990 Census data for each marketing area have been compiled and are presented in the information that follows. Figures D.1 through D.4 represent aggregated economic data from all 15 states to the total for Western's service region.

Billings Area

Number of states:	6	
Number of counties:	302	
Population:	4,649,130	
Square miles:	350,160	
Counties with at least 100,000 population:	7	2.3%
Counties with at least 100 people per mile^2:	5	1.7%

State	Counties	Population	Percent
Iowa	34	626,700	13.5%
Minnesota	36	708,700	15.2%
Montana	47	573,900	12.3%
Nebraska	66	1,405,530	30.2%
North Dakota	53	636,900	13.7%
South Dakota	66	697,400	15.0%

	County Population	County Population per mile^2
Mean	15,392	13
Median	7,965	9
Maximum	416,444	1,258
Minimum	500	1

Metropolitan Statistical Areas	Population
Billings MT	113,000
Bismarck ND	83,800
Fargo ND	154,400
Grand Forks ND	71,000
Great Falls MT	77,500
Lincoln NE	215,400
Omaha NE	621,300
Sioux City IA	115,000
Sioux Falls SD	125,100

Loveland Area

Number of states:	4	
Number of counties:	173	
Population:	5,246,367	
Square miles:	249,107	
Counties with at least 100,000 population:	12	6.94%
Counties with at least 100 people per mile^2:	12	6.94%

State	Counties	Population	Percent
Colorado	49	3,045,812	58.1%
Kansas	77	1,640,300	31.3%
Nebraska	27	172,855	3.3%
Wyoming	20	387,400	7.4%

	County Population	County Population per mile^2
Median	7,453	6
Maximum	467,610	3,051
Minimum	462	2

Metropolitan Statistical Areas	Population
Boulder CO	227,300
Casper WY	60,200
Cheyenne WY	73,300
Colorado Springs CO	405,000
Denver CO	1,633,300
Fort Collins CO	190,700
Greeley CO	132,300

Kansas City KS	619,600
Lawrence KS	82,900
Pueblo CO	123,100
Topeka KS	162,000

Phoenix Area

Number of states:	4	
Number of counties:	29	
Population:	21,459,400	
Square miles:	200,704	
Counties with at least 100,000 population:	12	41.4%
Counties with at least 100 people per mile^2:	5	17.2%

State	Counties	Population	Percent
Arizona	15	3,740,000	17.4%
California	8	16,845,400	78.5%
Nevada	3	786,600	3.7%
New Mexico	3	87,400	0.4%

	County Population	County Population per mile^2
Mean	739,979	107
Median	96,200	11
Maximum	8,967,900	3,104
Minimum	2,600	1

Metropolitan Statistical Areas	Population
Anaheim CA	2,451,100
Las Vegas NV	773,400
Los Angeles CA	8,967,900
Phoenix AZ	2,169,700
Riverside CA	2,724,000
San Diego CA	2,569,200
Tucson AZ	677,900
Yuma AZ	108,900

Sacramento Area

Number of states:	2	
Number of counties:	63	
Population:	13,930,200	
Square miles:	166,631	
Counties with at least 100,000 population:	29	46.0%
Counties with at least 100 people per mile^2:	2:22	34.0%

State	Counties	Population	Percent
California	50	13,507,600	97.0%
Nevada	13	422,600	3.0%

	County Population	County Population per mile^2
Mean	221,114	84
Median	80,800	43
Maximum	1,512,900	15,510
Minimum	1,100	1

Metropolitan Statistical Areas	Population
Bakersfield CA	558,900
Chico CA	185,300
Fresno CA	682,900
Merced CA	181,800
Modesto CA	384,400
Monterey CA	363,100
Oakland CA	2,111,700
Redding CA	151,600
Reno NV	260,000
Sacramento CA	1,523,300
San Francisco CA	1,611,700
San Jose CA	1,512,900
Santa Barbara CA	373,500
Santa Cruz CA	233,100
Santa Rosa CA	397,700
Stockton CA	490,600
Tulare CA	318,700
Vallejo-Napa CA	467,000
Ventura CA	680,700
Yuba City CA	124,400

Salt Lake City Area

Number of states:	6
Number of counties:	179
Population:	6,918,882
Square miles:	376,640
Counties with at least 100,000 population:	15 8.3%
Counties with at least 100 people per mile^2:	14 7.8%

State	Counties	Population	Percent
Colorado	14	248,582	3.6%
Nevada	1	34,900	0.5%
New Mexico	30	1,447,400	20.9%
Texas	102	3,388,000	49.0%
Utah	29	1,738,800	25.1%
Wyoming	3	61,200	0.9%

	County Population	County Population per mile^2
Mean	38,653	18
Median	12,800	6
Maximum	732,900	994
Minimum	100	0.4

Metropolitan Statistical Areas	Population
Abilene TX	119,500
Albuquerque NM	491,300
Amarillo TX	188,000
Brownsville TX	263,000
Corpus Christi TX	350,500
El Paso TX	602,600
Laredo TX	135,600
Las Cruces NM	138,600
Lubbock TX	224,100
Midland TX	107,400
Mission TX	393,000
Odessa TX	118,000
Provo UT	266,400
Salt Lake UT	1,083,200
San Angelo TX	99,300
Santa Fe NM	118,700

Figure D.1. Personal Income by Industry Category for the Years 1969-2040 for the States in Western's Marketing Area (U.S. Department of Commerce 1992)

Figure D.2. Employment by Industry Category for the Years 1969-2040 for the States in Western's Marketing Area (U.S. Department of Commerce 1992)

Figure D.3. Personal Income Trends and Projections for the Years 1969-2040 for the States in Western's Marketing Area (U.S. Department of Commerce 1992)

Figure D.4. Total Personal Income for the Years 1969-2040 for the States in Western's Marketing Area (U.S. Department of Commerce 1992)

REFERENCES

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APPENDIX E Resource Description

Resource Descriptions

This section describes different resource types that may be used for electricity generation. The resource mix includes both supply-side (generation) and demand-side (conservation and load management) resources. Table E.1 lists existing generating resource types with more than 25 megawatts of capacity located in the 15 states served by Western. The locations of these resources are shown in Figure E.1. Some of these resources are difficult to characterize in consistent terms. Thermal and nonthermal, generation and conservation, and fossil-fuel and renewable technologies are difficult to boil down to one meaningful table.

Table E.2 shows generation output and capacity for Western's service region by resource type for the years 1995, 2005, and 2015. The resources included in the model for potential growth in generation capacity over the next 20 years are simple-cycle combustion turbine, combined-cycle combustion turbine, nuclear, hydroelectric, combined renewables, conventional (pre-1985) coal, and new coal technologies. It was assumed that pre-1985 coal generation used pulverized coal technology. For purposes of assessing environmental impacts, new coal technology was assumed to be split between three technologies: pulverized coal, atmospheric fluidized bed coal, and integrated gasification combined-cycle coal.

Table 4.1 in Chapter 4 of the main body of the EIS summarizes environmental and planning information for the generation portion of the fuel cycle. The information is generic in nature; it does not apply to any particular plant, but rather represents a range of plants or calculated values.

Descriptions of the energy resources and any associated environmental impacts are provided here. The effects of various types of air emissions are described in greater detail in Chapter 3, Section 3.2.1.

The utility industry has been built around central power plants that are tied together and connected to customers by a transmission and distribution grid of powerlines. Renewable resources that are now being developed may not fit this system as well as traditional power plants. Table E.3 shows the potential to develop renewables in each state in Western's service territory. Some renewable energy resources (e.g., solar) may be virtually unlimited. However, barriers such as remote locations, infringement on a utility's ability to dispatch resources, and perceived technological and economic uncertainty limit the deployment of some renewable resources on a wider scale. Table E.4 summarizes constraints facing renewable resource development.

Table E.1. Power Plants in Western's Service Region Over 25 Megawatts(MW) (Power Magazine 1991)

	Plant	Capacity in MW and Type
ARIZONA		
1	Agua Fria	390ST 223CT
2	Apache	399ST 84CT 80CC
3	Cholla	1,156ST
5	Cross Cut	30ST 3HY
6	Davis	225HY
7	De Moss-Petrie	106ST 66CT
9	Glen Canyon	1,267HY
10	Horse Mesa	130HY
11	Irvington	505ST 81CT
12	Kyrene	108ST 227CT
13	Mormon Flat	58HY
14	North Loop	108CT
15	Ocotillo	220ST 174CT
16	Roosevelt	35HY
17	Saguaro	225ST 114CT
18	Navajo	2,410ST
20	Yurna Axis	75ST 75CT
21	Phoenix	75ST 106CT 396CC
22	Santan	414CT
25	Coronado	821ST
26	Hoover	671HY
27	Springerville	350ST
28	Palo Verde	3,810NU
CALIFORNIA		
1	Alamitos	1,982ST 163CT
2	Avon	40ST
3	Balch	128HY
5	Belden	118HY
6	Big Cr #1	70HY

7	Big Cr #2	58HY
8	Big Cr #3	143HY
9	Big Cr #4	84HY
10	Big Cr #8	59HY
11	Black	154HY
12	Big Cr #2A	80HY
13	Brawley	13IC 22CT
14	Broadway	171ST
15	Bucks Cr	66HY
16	Butt Val	36HY
17	Camino	142HY
18	Caribou #1	75HY
19	Caribou #2	110HY
20	Castiac	1,331HY
22	Contra Costa	1,277ST
23	Control Gorge	38HY
24	Cool Water	147ST 580CC
25	Chicago Park	42HY
26	Copco #2	28HY
27	Cresta	68HY
29	Don Pedro	137HY
30	Coachella	92CT
31	Devil Canyon	120HY
32	Drum #1	44HY
33	Donnels	54HY
34	Dutch Flat	26HY
35	Ellwood	62CT
36	El Centro	190ST
37	El Segundo	996ST
39	Electra	90HY
40	Encina	856ST 18CT
41	Etiwanda	912ST 163CT
42	Folsom	198HY
43	Exchequer	80HY
44	Forbestown	29HY
45	Geysers	1,200ST
46	Glenarm	65ST 64CT
47	Grayson	163ST 152CT
48	Haas	140HY
49	Hyatt	644HY
50	Harbor	259ST 94CT
51	Haynes	1,606ST
52	Highgrove	170ST
53	Holm	135HY
54	Humboldt Bay	102ST
55	Hunters Point	372ST 61CT
56	Huntington Bch	872ST 163CT
57	Middle Fork	110HY
58	Jaybird	133HY
59	Judge Francis Carr	142HY
60	Kearny	165CT
61	Kerckhoff	1 39HY
62	Kern	180ST
63	Ralston	79HY
64	Rancho Seco	918NU
65	Kern Rvr #3	32HY
66	Keswick	75HY
68	King's Rvr	44HY
69	Kirkwood	68HY
70	Long Beach	180ST 588CT
71	Loon Lake	74HY
72	Thermalito	117HY
73	Mammoth Pool	129HY
74	Mandalay	436ST 163CT
77	Middle Gorge	38HY
78	Miramar	39CT
79	Moccasin	90HY
80	Morro Bay	1,056ST
81	Moss Landing	2,177ST
82	Narrows	47HY
83	Woodleaf	52HY
84	North Island	39CT
85	Ormond Beach	1,613ST
87	Oakland	189CT
88	O'Neill	25HY
89	Parker	120HY
90	Pilot Knob	33HY
91	Pit #1	56HY
92	Pit #3	81HY
93	Pit #4	90HY
94	Pit #5	140HY

95	Pit #6	80HY
96	Pit #7	92HY
97	Pittsburg	2,027ST
98	Poe	142HY
101	Potrero	318ST 178CT
102	Redondo Beach	1,579ST
104	Rock Cr	114HY
106	San Luis	424HY
107	Salt Springs	39HY
108	San Bernardino	130ST
109	San Francisquito #1	72HY
110	San Francisquito #2	42HY
111	San Onofre	1,531NU
112	Scattergood	610ST
113	Shasta	452HY
114	Silver Gate	247ST
115	South Bay	714ST 19CT
116	Spring Cr	150HY
117	Stanislaus	82HY
119	Tiger Cr	52HY
120	Trinity	107HY
121	Union Val	33HY
122	Upper Gorge	38HY
123	Valley	546ST
126	White Rock	190HY
127	Magnolia	78ST 25CT
128	McClure	50CT
129	Naval Station	28CT
131	New Melones	300HY
132	Olive	105ST 67CT
134	Warne	74HY
141	Diablo Cnyn	2,78ST 2,190NU
144	McClellan	49ST
145	Colgate	315HY
148	Drum #2	49HY
149	Rockwood	50CT
150	Bottlerock	55ST
151	Pine Flat	165HY
152	Tullock	34HY
153	El Dorado	25HY
154	Helms	1,170HY
155	Coldwater Cr	130ST
156	Smudgeo	78ST
157	Heber	70ST
158	Eastwood	200HY
159	Collierville	230HY

COLORADO

1	Alamosa	20ST 58CT
3	Arapahoe	251ST
4	Blue Mesa	60HY
5	Clark	39ST
6	Comanche	778ST
7	Cabin Cr	300HY
8	Cameo	75ST
9	Fort Lupton	110CT
10	Cherokee	802ST
11	Estes	45HY
12	Flatiron	74HY
13	Birdsall	63ST
14	Fruita	29CT
16	Hayden	465ST
17	Republican Rvr	225CT
19	Lamar	35ST 2IC
20	Drake	282ST
21	Morrow Point	120IC
22	Nucla	38ST
23	Pole Hill	33HY
24	Pueblo	30ST 10IC
28	Valmont	282ST 66CT
29	Zuni	115ST
30	Burlington	118CT
31	Craig	1,284ST
32	Crystal	29HY
34	Nixon	207ST
35	Pawnee	500ST
36	Mt. Elbert	200HY
37	Rawhide	255ST

IOWA

1	Ames	133ST 1IC

5	Burlington	212ST
6	Coralville	54CT
7	Council Bluffs	781ST
8	Des Moines #2	270ST
9	Dubuque	81ST 4IC
10	Arnold	597NU
11	Fair Station	63ST
12	Humboldt	45ST
13	Electrifarm	224CT
14	Keokuk	139HY
15	Lansing	339ST 2IC
17	Kapp Station	237ST
18	Muscatine	284ST
19	Neal	1,038ST 6IC
20	Pella	42ST
21	Prairie Cr	149ST
22	River Hills	124CT
23	Riverside	136ST
24	Summit Lake	68IC 68CC
25	Sutherland	157ST
26	Sycamore	158CT
27	Wisdom	38ST
28	Sixth St.	92ST
29	Parr	36CT
30	Streeter	78ST
31	Ottumwa	675ST
32	Louisa	730ST
33	Marshalltown	5IC 189CT
34	Gas Turbine	25CT
35	Indianola	14IC 21CT
36	Maynard	54ST
KANSAS		
1	Abilene	78CT
2	Mullergren	120ST
3	Clifton	3IC 85CT
6	Cimarron Rvr	50ST 15CT
9	Colby	12ST 16CT
11	Garden City	112ST 112CT
13	Evans	540ST
16	Hutchinson	250ST 342CT
17	Judson Large	168CT
18	Kaw	161ST
19	LaCygne	1,559ST
20	Lawrence	614ST
21	McPherson #1	26ST
22	McPherson #2	32ST 200CT
25	Gill	343ST
26	Neosho	114ST
27	Riverton	135ST 44CT
30	Quindaro	221ST 147CT
32	Ross Beach	36ST
34	Wellington	34ST
36	Winfield	45ST 11CT
37	Tecumseh	231ST 54CT
38	Coffeyville	74ST
40	Jeffrey	2,160ST
42	Nearman Cr	250ST
43	Holcomb	296ST
44	Wolf Cr	1,150NU
45	Ottawa	19IC 12CT
MINNESOTA		
1	King	598ST
2	Blue Lake	228CT
3	Cascade Cr	35CT
4	Austin	29ST 6CT
5	Black Dog	488ST
7	Montgomery	27CT
9	Boswell	1,070ST
10	Hutchinson	21IC 25CT16CC
11	Prairie Island	1,186NU
13	Fox Lake	105ST 27CT
15	Elk Rvr	46ST
16	Silver Lake	79ST
17	Syl Laskin	116ST
18	Granite City	72CT
21	High Bridge	398ST
22	Hoot Lake	137ST 1HY
24	Inver Hills	324CT
26	Key City	72CT

29	Hibbard	123ST
30	Minnesota Val	46ST
32	Moorhead	23ST 10CT
34	New Ulm	30ST 24CT
35	Owatonna	26ST 19CT
37	Riverside	309ST
40	Thomson	67HY
44	West Faribault	48CT
45	Wilmarth	25ST
46	Willmar	30ST
48	Cambridge	8IC 23CT
50	Monticello	569NU
51	Northeast	32ST
52	Sherburne Cty	1,440ST
54	Virginia	38ST
55	St. Bonifacius	48ST
56	Fairmont	32ST 13IC
57	Hibbing	31ST
MONTANA		
1	Colstrip	2,272ST
2	Canyon Ferry	51HY
3	Cochrane	48HY
4	Bird	69ST
5	Fort Peck	165HY
6	Holter	40HY
7	Hungry Horse	328HY
8	Corette	173ST
9	Kerr	168HY
10	Lewis & Clark	50ST
11	Libby	525HY
13	Morony	46HY
15	Noxon Rapids	398HY
16	Rainbow	36HY
17	Ryan	48HY
18	Thompson Falls	30HY
19	Yellowtail	252HY
20	Glendive	30CT
NEBRASKA		
1	Columbus	42HY
2	Bluffs	43ST
3	Burdick	93ST 15CT
4	Canaday	107ST
5	Cooper	778NU
6	Fort Calhoun	502NU
7	Fremont	129ST
10	Hallam	50CT
11	Hebron	43CT
12	Jones Street	130CT
15	Lincoln	31CT
16	North Omaha	646ST
17	Sarpy County	110CT
18	Sheldon	225ST
19	McCook	49CT
20	North Platte	29HY
21	Gentleman	1,278ST
22	Nebraska City	565ST 30IC
23	North Denver	39ST
24	Platte	100ST
25	Energy Center	72ST
26	Kingsley	38HY
27	Rokeby	66CT
NEVADA		
1	Clark	190ST 270CT
2	Fort Churchill	220ST
3	Hoover	676HY
4	Mohave	1,636ST
5	Reid Gardner	342ST
6	Sunrise	82ST 75CT
7	Tracy	243ST 25CT
8	Westside	32IC
9	Valmy	254ST
NEW MEXICO		
1	Algodones	51ST
4	Cunningham	265ST
5	Lordsburg	37ST 13CT 5CC
6	Four Corners	2,268ST
7	N Lovington	49ST 19IC

8	Maddox	114ST 66CT
9	Person	120ST
11	Rio Grande	266ST
12	Reeves	175ST
14	San Juan	1,572ST
15	Plains Escalante	233ST
16	Animas	32ST 2IC
17	Navajo	30HY
NORTH DAKOTA		
1	Garrison	490HY
2	Young	719ST
4	Stanton	172ST
7	Olds	656ST
8	Heskett	100ST
9	Neal	50ST
10	Jamestown	50CT
11	Coal Cr	1,012ST
12	Coyote	414ST
13	Antelope Val	876ST
14	Lerald	35CT
SOUTH DAKOTA		
1	Big Bend	464HY
2	Big Stone	456ST
3	Fort Randall	320HY
4	Oahe	700HY
5	French	26ST 8IC 91CT
6	Kirk	32ST
9	Pathfinder	75ST
10	Aberdeen	8ST 28CT
11	Gavins Point	100HY
12	Lake Preston	2IC 26CT
13	Spirit Mound	120CT
TEXAS		
1	Amistad	66HY
2	Big Brown	1,186ST
4	Davis	704ST
5	Bryan	126ST 22CT
6	Buchanan	33HY
7	Newman-Dallas	98ST
8	Cedar Bayou 2,	280ST
9	Collin	156ST
10	De Cordova	799ST
12	Dallas	163ST
13	Decker Cr	788ST 206CT
14	Deepwater	156ST
15	Denison	70HY
16	Denton	190ST
17	Falcon	32HY
18	Joslin	261ST
19	Eagle Mtn	707ST
21	Fayette	1,690ST
23	Graham	635ST
24	Granite Shoals	46HY
25	Greens Bayou	408ST 396CT
27	Handley	1,434ST
28	Clarke	84CT
29	Holly Ave	106ST 51CT
30	Holly St	628ST
31	Fort Phantom	347ST
32	Bates	189ST
34	Knox Lee	501ST
35	Lake Cr	316ST 6IC
36	Lake Hubbard	928ST
37	La Palma	231ST 49CT
38	Laredo	190ST
39	Jones	496ST
40	Leon Cr	251ST
41	Lewis Cr	542ST
42	Hill	587ST
43	Lone Star	50ST 49CT
44	Marshall Ford	69HY
45	Marble Falls	30HY
46	Mission Rd	114ST
47	Moore County	49ST
48	Morgan Cr	827ST 2IC 537CT
49	Mountain Cr	958ST
50	Harrington	1,063ST
51	Newman	266ST 170CT 120CC

52	Nichols	475ST
53	North Lake	709ST
54	North Main	81ST
55	North Texas	76ST
56	Nueces Bay	596ST
57	Oak Cr	75ST
58	Sommers	893ST
59	Robinson	2,316ST 14CT
60	Paint Cr	218ST
61	Parkdale	341ST
62	Lake Pauline	40ST
63	Pearsall	75ST
64	Permian Basin	703ST
65	Pirkey	719ST
66	Plant 2	81ST 5IC
67	Plant X	442ST
69	Miller	366ST
70	Olinger	335ST
71	Tolk	1,080ST
72	Monticello	1,979ST
73	Riverview	27CT
75	Sabine	2,050ST
76	Bertron	826ST 41CT
77	Rayburn (Victoria)	25ST 22CT
78	San Angelo	100ST 25CT
79	Seaholm	120ST
80	Silas Ray	43ST 53CT
81	Gideon	622ST 10IC
82	Stryker Cr	704ST
83	Wharton	439ST 731CT 226CC
84	Tradinghouse Cr	1,380ST
85	Trinidad	308ST 4IC
88	Brauning	894ST
89	Valley	1,176ST
90	Victoria	557ST
91	Parish	3,952ST 14CT
92	Tuttle	494ST
93	Webster	389ST 14CT
95	Wilkes	882ST
96	Rio Pecos	99ST 5CT38CC
97	River Crest	113ST
102	Ferguson	446ST
103	Toledo Bend	81HY
104	Whitney	30HY
106	Celanese	37ST 13CC
107	Coleto Cr	609ST
108	Copper	80CT
109	Denver City	50ST
110	Martin Lake	2,379ST
111	Neches	290ST
113	Rayburn (Jasper)	52HY
114	Seymour	1,200ST
115	Welsh	1,584ST
116	Gibbons Cr	408ST
117	Sandow	591ST
118	Limestone	1,488ST
119	Oklaunion	640ST
121	S Texas Proj. #1	1,354NU
122	Dansby	105ST
123	Powerlane	87ST
124	Deely	892ST
125	San Miguel #1	448ST
126	University Util.	20ST 15CT
127	Morris Sheppard	25HY

UTAH

1	Carbon	189ST
2	Cutler	30HY
3	Flaming Gorge	108HY
4	Gadsby	252ST
5	Hale	60ST
9	Huntington Cnyn	893ST
10	Hunter	1,338ST
12	Bonzana	400ST
13	Intermountain	1,522ST

WYOMING

1	Alcova	36HY
2	Bridger	2,024ST
3	Johnston	788ST
5	Fremont Cnyn	48HY

8	Kortes	36HY
9	Naughton	711ST
11	Osage	36ST 1IC
12	Seminole	45HY
13	Laramie	1,650ST
14	Wyodak	331ST
15	Glendo	38HY

CC = Combined Cycle
CT = Combustion Cycle
HY = Hydroelectric
IC = Internal Combustion
NU = Nuclear
ST = Fossil Steam

Note: Numbers in first column correspond to plant locations on map in Figure E.1.

E.1 PULVERIZED COAL

Modern pulverized coal plants crush or pulverize coal into fine particles which are blown into a burner. Heat released from ignition of these particles boils water. The resulting steam is piped to a turbine which drives an electricity-producing generator. Typically waste heat is transferred to cooling water as low-pressure exhaust steam is condensed.

The combustion exhaust gases contain sulfur oxides, nitrogen oxides, particulates and carbon dioxide - all of which contribute to poor air quality. Up to 90 percent removal of sulfur emissions is possible using dry flue gas desulfurization. Formation of nitrogen oxides (NOx) is impeded using the staged combustion concept of a low-NOx burner. Flue gas may contain small particulates originating during combustion. Inhalation of such matter affects human health. Particulates may be scrubbed from the dry flue gas in a baghouse or collected using electrostatic precipitation. The technology is not currently available to prevent carbon dioxide emissions in a cost-effective manner.

Large volumes of water are necessary for general plant services, boiler makeup, and condenser cooling. Water in the circulating condenser system accumulates dissolved metals and other contaminants as water vapor evaporates. To dilute this solution, some water is discharged and replaced with fresh water. Low stream flows and water rights disputes may result from continual removal of makeup water to replace the volume that evaporates in the cooling tower. Chemical precipitation, sedimentation and neutralization, and the use of lined ash disposal pits are the most common methods for treating the blowdown water.

Solid wastes accumulate from fly ash, scrubber sludge, bottom ash, and coal preparation waste. Sulfur compounds, calcium, chloride, and ash are usually deposited in ponds then landfills. Large land tracts are required for direct ponding. Leaching could be a problem, but lined ponds address this complication.

E.2 ATMOSPHERIC FLUIDIZED BED COAL

One modification to the pulverized coal power generation method is the atmospheric fluidized bed. Jets of air circulate crushed coal and limestone through a vertical combustion chamber. Sulfur in the coal reacts with the limestone preventing formation of sulfur oxides in the exhaust gases. Nitrogen oxides are reduced due to a lower operating temperature. The improved efficiency of this procedure may decrease the amount of carbon dioxide released to the atmosphere. Air and water quality impacts are the same as for pulverized coal, except that emissions are decreased.

E.3 INTEGRATED COAL GASIFICATION COMBINED-CYCLE COMBUSTION

Another advanced technology for burning coal is gasification. When coal reacts with oxygen and steam, combustible gases such as carbon monoxide and hydrogen are produced. These gases are expanded in a turbine to produce electricity. A steam turbine is then powered using the heat retained from the combustion cycle. Sulfur is removed before combustion occurs to eliminate sulfur emissions. Providing a reduced temperature in the combustion turbine limits the nitrogen oxide emissions. Water quality and solid waste are dealt with as with pulverized coal. There is no scrubber sludge due to elemental sulfur removal, but waste slag from the gasifiers and ash from the production of gas must be disposed of.

E.4 NATURAL GAS-FIRED COMBINED-CYCLE COMBUSTION TURBINE

A combustion turbine is similar to a jet engine. Large volumes of air are forced to high pressures in a compressor. Natural gas is injected and combustion occurs. The resulting high-temperature, high-pressure exhaust gases are expanded in a turbine which produces electricity. The combined-cycle combustion turbine uses the heat retained from the combustion cycle to power a steam turbine. The combustion cycle is referred to as the "topping" cycle and the steam turbine cycle is the "bottoming" cycle. Air quality is affected by the release of nitrogen oxides, carbon dioxide, and particulates into the atmosphere. Minimal solid waste is produced, and impacts to the water table are minimal.

E.5 DIESEL

Diesel is a heavy petroleum product commonly used in combustion engines for the production of power. Exhaust gases resulting from diesel combustion drive a turbine which generates electricity. These exhaust gases have a high content of nitrogen oxides along with carbon dioxide. Some particulates that are also released have been identified as possible carcinogens when inhaled (Brown 1988). Diesel power does not produce water effluents or solid wastes. Many municipal utilities in Western's service territory own small diesel power plants. These plants are used as backup sources of power in case of interruptions from other sources during emergencies or maintenance periods.

E.6 NUCLEAR

Fission is the reaction that drives nuclear electricity production. Uranium is mined, processed, and formed into fuel pellets which are contained in the nuclear power plant reactor vessel. Fission converts the uranium into an isotope, uranium-235, releasing heat energy. In a boiling water reactor, this heat is used to create steam which is directed to a turbine generator to produce electricity.

A pressurized water reactor operates at high pressure to prevent the primary cooling water from boiling. The primary cooling water is pumped through the reactor vessel where it is heated. It is then pumped through a heat exchanger where it heats secondary cooling water to produce steam, which is used to drive a turbine and generate electricity. The low-pressure exhaust steam is condensed and recycled. Waste heat from condenser cooling water is discharged to the environment. Separation of the primary and secondary cooling systems prevents contamination of the turbine system with radionuclides that may be in the primary coolant.

Waste heat is the primary effluent to the atmosphere from nuclear power generating plants. Water vapor plumes can lead to icing or fogging. Small quantities of radionuclides are released to the atmosphere with the water vapor, but at levels below normal background radiation. Low contamination levels are maintained by filtration through charcoal beds. Particulates are controlled in a similar manner. Extensive monitoring networks typically ensure that routine emissions of radionuclides are very low.

Spent fuel contains beta- and gamma-emitting isotopes and transuranic materials with half-lives of around 10,000 years. Currently, deep pools of water at power plant sites house these materials, until a geologic repository can be constructed for permanent storage.

E.7 BIOMASS

Biomass is a term used to designate all energy materials derived from biological sources. These materials include forest residues, waste products from animals and food processing, agricultural and forest crops grown for fuel, and municipal solid wastes. Biomass and wastes can be used to produce heat, steam, electricity, liquid fuels for transportation, natural gas substitutes, and other materials, such as alternatives to petrochemical products and fertilizers.

The heat content, moisture levels, and other physical characteristics of biomass resources differ widely, but typically somewhat lower efficiency is obtained compared with fossil fuel combustion. The cost of collecting and transporting large quantities of biomass materials for commercial energy applications can be great. Thus, biomass that has already been collected for other reasons, such as forest product and food processing industry wastes and municipal solid wastes, are the most cost-effective resources (INEL et al. 1990, p. B-6). However, supplies may vary with the season and weather, crop patterns, and fluctuations in the primary markets.

Biomass feedstocks are renewable and the potential resource is large. Figure E.2 shows biomass production areas in Western's service region. According to the Western biomass energy resource assessment, major metropolitan areas are primary locations for the use of municipal and other wastes (INEL 1987b, p. 15).

The emissions of criteria pollutants from combustion of biomass are usually less than those from fossil fuels since biomass fuels are typically low in sulfur (except municipal solid wastes) and nitrogen. Air emissions may contain uncombusted hydrocarbon and particulate matter. Pollutants can be controlled by furnace design, combustion control, and flue gas cleaning technologies. The small amount of ash produced may be used as a soil supplement, depending on contaminants. Biomass materials reduce wastes from industrial processes or from the solid waste stream in general. Biomass combustion makes a zero net contribution to atmospheric carbon dioxide if the vegetation from which the fuels are derived is regrown.

Thermal combustion of municipal solid wastes may produce toxic gas emissions, including dioxins, NOX, and chlorinated gases, as well as solid residue and ash. If burned, fossil fuel-based municipal solid wastes, for example plastics, will contribute to atmospheric carbon dioxide. Problems with waste processing and burning have been more common with refuse-derived fuel facilities than with mass burn plants. Emission control technologies can meet current air quality standards, but there is public concern in many areas about the adequacy of the standards.

Figure E.2 Potential Biomass Resources (INEL 1987a, p.A-5)

E.8 HYDROELECTRIC

Hydroelectric facilities employ the kinetic energy in flowing or falling water to turn hydraulic turbines, which drive generators to produce electricity. There are two types of conventional hydropower facilities: storage or run of the river. The majority of conventional hydro projects are incorporated into dams or other impoundments structures that capture and store water from streams and rivers. Run of the river facilities use the flow of available water, whether occurring naturally or as releases from man-made facilities. Pumped-storage facilities are nonconventional operations using pumped water instead of free-flowing water.

The principal advantages of using hydropower are a large resource base, low emissions, low operating costs, long service life, and the capability of these systems to respond quickly to utility load swings. Small-scale projects (<20 MW capacity) can have short lead times and costs can be low for projects that add capacity to existing facilities. Because stream flows vary with annual weather conditions, part of the average output of most projects is nonfirm energy, but unlike wind or solar power, hydropower is rarely intermittent on a daily basis. Disadvantages are high initial capital cost, complex environmental issues, and competition with other interests for water resource use. Siting, licensing, and design are typically complex and frequently require long lead times.

The potential for new hydroelectric resources exists widely throughout Western's service region (see Figure E.3). The Western brief small-scale hydroelectric assessment identifies many existing sites where capacity upgrades are possible (Tudor Engineering 1984). Although the total potential resource is large, available stream flows, topographic features, competing uses, and economic, social, and institutional factors limit development of hydroelectric facilities (INEL 1987a, p. A-30). Most new project developments are for facilities with less than 20 MW of installed capacity. Potential environmental impacts of hydroelectric development are shown in Table E.5.

E.9 GEOTHERMAL

Geothermal power plants use naturally heated underground hot water or steam located in pockets or rocks as an energy source for electricity production. Although surface activity in active volcanoes, hot springs, fumaroles, and geysers may provide accessible geothermal resources, most geothermal plants tap underground hot water with wells drilled from the surface. Three major hydrothermal (hot water) conversion technologies are used for electricity generation: dry steam, flash steam, and binary cycle systems. The technology employed depends on the temperature and makeup of the geothermal resource.

In dry steam systems, conventional turbine generators produce electricity from dry natural steam taken directly from a production well. Using natural steam eliminates the boiler used in conventional steam generator systems. Most of the condensate can be used as cooling tower makeup water. Injection wells recycle spent fluids back into the reservoir. Dry steam systems have the highest quality and lowest cost of all geothermal technologies. However, dry stream reservoirs are rare. The Geysers in northern California is the only commercial dry steam field in the United States.

Figure E.3 Potential Hydroelectric Resources (INEL 1987a, p. A-31)

In flash steam systems, high temperature liquids boil in a separator as pressure is reduced as the fluid reaches the ground surface. The steam is separated from the residual liquid and used to drive a turbine generator. Binary cycle systems are used to generate electricity from hydrothermal resources not hot enough for efficient steam production. The heat of the geothermal liquid vaporizes a secondary working fluid for use in the turbine. Commercial binary power plants are operating in California, Nevada, New Mexico, and Utah (INEL et al. 1990, p. C-2).

Geothermal resources can be found throughout Western's service area (see Figure E.4). High pressure hot brines and dry hot rock resources are also available but conversion technologies are still experimental. The Western brief geothermal assessment concluded that potential power generation sites exist in Arizona, California, Colorado, Nevada, New Mexico, and Utah (Lunis, Blackett, and Foley 1982, p. 13).

The major environmental concerns associated with geothermal development are the release of hydrogen sulfide, disposal of spent geothermal fluids, noise, and impacts on fish and wildlife habitat. Emissions do not contribute to smog or acid rain and carbon dioxide (CO_2) emissions are less than 5 percent of coal plant emissions (INEL et al. 1990, p. C-1). Sulfurous gases are effectively removed by existing scrubbing technology and binary technology can eliminate all emissions.

Water quality impacts include potential contamination of surface and ground water from reinjection wells, and possible depletion of surface water resources to recharge geothermal reservoirs (Baechler, Fickeisen, and Hendrickson 1990, p. 6-2). Subsidence may be a concern if withdrawal of geothermal fluids exceeds natural recharge or injection. Reinjection may cause seismic activity in some areas due to the high local pressures produced (Baechler, Fickeisen, and Hendrickson 1990, p. 6-4).

In some systems, flash steam operations produce sludges containing hazardous metals (Pasqualetti and Dellinger 1989). Ways of removing and recovering these metals using biotechnology and other methods are being investigated (INEL et al. 1990, p. C-14). Sludge containing toxic metals is a concern in California's Imperial Valley.

Table E.5. Potential Annual Routine Environmental Impacts for Hydroelectric Generation

Potential Impacts	Generation
Air Pollutants	None
Water Quality Impacts	
Consumption (acre-ft)	Water use is not consumptive.
Thermal Discharge	No thermal discharge.
Other Impacts	Water temperature changes, due to increased reservoir surface area and depth, reduced shading, and slow water movement, may exceed fish temperature tolerance. Reduction in dissolved oxygen could impact fish and encourage algae blooms. Air entrained in water flowing through generators or over spillways can cause gas supersaturation, which can be lethal to fish. Sediment collection behind dams can alter river substrate and impact invertebrate population. Fish and wildlife can be stranded, lose habitat, or have migration routes blocked by hydro development.
Land Effects	
Acreage Requirements	Depends on site and technology.
Other Impacts	Large hydroelectric projects require vast amounts of land for reservoirs and large dams alter natural landscapes; storage reservoirs may change seasonal water levels and can result in unattractive and unproductive beach areas; recreational opportunities are altered by water impoundment and loss of free-flowing water; opportunities for fishing, sailing, and boating may be developed while rafting will no longer be available
Waste Streams	Limited to office and maintenance activities.

Source: Baechler, Fickeisen, and Hendrickson 1990.

E.10 SOLAR

Solar thermal systems, which indirectly convert sunlight into electricity, consist of collectors to concentrate the solar energy, receivers to heat a working fluid, and conversion units to convert the heat of the fluid to electricity. Many plants have storage capabilities to increase availability. Central receiver and parabolic trough solar thermal systems are currently being used to generate power by utilities and others.

Photovoltaic cells are solid-state electronic devices that directly convert solar energy into electricity. Concentrator photovoltaic technology uses lenses to focus and intensify the sunlight on the photovoltaic cells. These systems require a tracking system, unlike flat-plate photovoltaics which typically are stationary panels. Photovoltaic systems are primarily used at remote installations such as transmitter stations.

Solar resources are renewable, widely available, and versatile. The available resource at a given site depends on the total insolation, which includes direct and diffuse components. Figure E.5 shows the annual average daily solar energy available on a south facing surface, tilted to match latitude.

Solar energy systems would produce minimal air pollutants and noise except during construction. However, large-scale solar electrical generation facilities require extensive land use. Wildlife habitat would be eliminated at many sites and conversion installations can be aesthetically displeasing, which may lead to stringent zoning regulations (Baechler, Fickeisen, and Hendrickson 1990, p. 10-2; INEL 1987a, p. A-45).

Solar thermal plants, which require water for condenser cooling, may impact fish and aquatic ecosystems in arid regions, although use of dry cooling water towers would eliminate this problem. Photovoltaic cells do not use cooling or otherwise consume water except for periodic cleaning of the collectors. Toxic chemicals, including sodium, organic oils, and molten salts, contained in heat exchange and storage fluid, might pose environmental hazards if accidentally released.

E.11 WIND

Wind energy devices use propeller-like blades to catch the power of air currents and spin an electric generator. Wind machines are usually grouped over many acres in wind parks. Wind turbines employ horizontal or vertical-axis rotors. Most residential and large existing wind machines are horizontal-axis units with capacity typically between 100 and 300 kW (BPA 1992, p. 3-36).

Wind energy is a vast and renewable resource and there are many wind resource sites within Western's service region (see Figure E.6). However, wind energy is dispersed and intermittent, and wind conditions are extremely localized. Available wind power increases as the cube of wind speed, so small differences in wind speed can make dramatic differences in the power output of a wind system (SERI 1983b, p.3). Wind power also increases with altitude above the ground (Elliott, Wendell, and Gower 1991). Wind power density is the total available power per square meter, assuming a wind energy system with 100 percent efficiency. Wind power classes range from 1 (9.8 mph and 100 watts/m2) to 7 (21.1 mph and 1,000 watts/m2). Generally, satisfactory wind resources are considered to be class 4 or greater (SERI 1983b, p. A-4).

Wind energy systems have few off-site environmental impacts. There are no direct water quality impacts. Wind conversion facilities require extensive land use but many prior land uses, such as grazing, can continue during operation at wind farms. Some installations may be aesthetically displeasing and noisy, which may lead to more stringent zoning regulations (INEL 1987a, p. A-53). Visual impacts may be of particular concern in scenic areas. Electromagnetic noise from wind turbine operation may interfere with television reception (Baechler, Fickeisen, and Hendrickson 1990, p. 11-2). Large-scale installations may interfere with bird and wildlife migrations and habitat (Estep 1989).

Figure E.4. Potential Geothermal Resources (INEL 1987a, p. A-21) E.10 Solar

Figure E.5. Annual Average Daily Global Solar Radiation on a South- Facing Surface (Tilt=Latitude) (SERI 1983a, p. A-10)

Table E.6. Cogeneration Potential in Western's Service Area

State	Power(MW)	Steam (lbs/yr)
Arizona	100	11500
California	8530	199500
Colorado	40	4700
Iowa	510	40100
Kansas	920	43800

Minnesota	450	26700
Montana	240	8000
Nebraska	80	7500
Nevada	2	90
New Mexico	120	10500
North Dakota	4	150
South Dakota	1	40
Texas	4260	416300
Utah	200	10600
Wyoming	10	2300

Source: INEL 1987a, p. A-15

E.12 COGENERATION

Cogeneration is the joint production of power, usually a combination of electrical and thermal energy. One example is burning fuel to create steam to produce electricity then using the "waste" heat for process heat, space conditioning, and agriculture and aquaculture production. Another example would be burning fuel to provide heat for an industrial process, for example heating a steel-making furnace, then using the exhaust steam from this process to drive a turbine to produce electricity.

Cogeneration is a well-established technology that can greatly improve fuel and facility utilization efficiency over separate production of power and thermal energy. According to the Western brief cogeneration technology assessment, an estimated 10 to 30 percent fuel savings is gained from cogeneration applications (EG&G Idaho 1982, p. 1).

Cogeneration has the potential to be used at existing power plants throughout Western's service area (INEL 1987a, p. A-12). Cogeneration facilities could also be installed at existing chemical, pulp and paper, food processing, petroleum refining, and primary metals plants. These are industries where large quantities of steam or heat are used to process materials and plant electric loads are high. Table E.6 gives estimates of the potential power and steam generation capacity associated with cogeneration by state.

The primary fuels used nationwide for cogeneration are natural gas (58 percent), coal (19 percent), and biomass, waste and other fuels (23 percent) (BPA 1992, p. 3-44). The environmental effects depend largely on the type of fuel used. Plant emissions would be similar to any combustion facility using these fuels. However, since thermal and electricity needs are supplied with a single energy source, there is less overall pollution than if separate energy sources are used.

Figure E.6. Annual Average Wind Power (Elliott et al 1986)

E.13 CONSERVATION

Conservation programs can provide both capacity and energy savings. Conservation efforts include incentives to conserve energy and research and demonstration projects to promote various energy-efficient technologies and vary widely depending on the sector in which they are implemented.

In the residential sector, conservation programs involve retrofitting existing homes to make them more energy efficient and promoting the use of energy-efficient home appliances. In the commercial sector, existing facilities such as office buildings, retail outlets, warehouses, hotels and motels, restaurants, grocery stores, health care facilities, and education buildings can be retrofitted and new buildings can be designed to be more energy efficient. Industrial conservation is achieved by retrofitting existing facilities and process equipment to use less energy and by building new facilities for maximum energy efficiency. Agricultural sector conservation programs focus on optimizing the use of water and increasing the energy efficiency of irrigation equipment (e.g., pumps and motors); runoff mitigation strategies are also encouraged.

The environmental effects of conservation measures are largely beneficial. However, most measures may have some adverse effects on the environment during installation or use (see Tables E.7 and E.8). Indoor air quality impacts have been the principal concern associated with conservation measures focusing on building efficiency. For more information on indoor air quality see Chapter 3, Section 3.2.2.

E.14 TRANSMISSION

Transmission and distribution systems carry power and energy produced by generating units to users or customers. Transmission lines, which provide the bulk of long-distance connections between plants and loads, deliver electricity to substations where the distribution system provides the delivery path to customers. Step-up transformers increase voltage from the generating facility output to transmission voltage.

Developing new generation and import energy resources may require construction of new or upgraded transmission lines to deliver the power to the load centers. Except in rare cases, cost and operating considerations limit transmission to above-ground systems. New lines could be located along existing right of ways or on new transmission corridors. Transmission and interconnection costs are particularly an issue for resources such as hydroelectric and geothermal that are geographically dispersed and often located far from existing utility grids.

Measures to reduce losses and improve transmission and distribution efficiencies include (NWPPC 1991, pp. 601-602):

* Replacing system components, such as transformers and conductors, with higher efficiency components
* Improving insulators
* Modifying system operating conditions, such as nominal voltage levels; modifying load characteristics, for example, reducing peak loads and reactive loads
* Reconfiguring the transmission and distribution system, for example, by reducing the average distance between a substation and its loads.

In addition, conservation voltage reduction can improve the efficiency of certain end-use equipment. Conservation voltage reduction measures are implemented only on the distribution system. Energy savings are realized at the end use and at distribution transformers.

Potential environmental effects of transmission lines and their operation include the physical effects of the structures and possible effects due to the electrical and magnetic fields around the lines (Baechler, Fickeisen, and Hendrickson 1990, p. 13-2). Transmission and distribution loss reduction measures may accelerate the removal of equipment contaminated by polychlorinated biphenyls (NWPPC 1991, p. 602). Hazards can be minimized through proper handling and disposal.

Table E.7. Summary of Potential Environmental Effects Resulting from Industrial Conservation Measures (a)

Table E.7. Summary of Potential Environmental Effects Resulting from Industrial Conservation Measures (a) , continued

Table E.7. Summary of Potential Environmental Effects Resulting from Industrial Conservation Measures (a) , continued

Table E.8. Conservation Measures and Their Impacts

Table E.8. Conservation Measures and Their Impacts,continued

E.15 REFERENCES

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APPENDIX F Selection of Environmental Factors

The analysis in this EIS is limited to reasonably foreseeable impacts, without knowing the specific activities that would be undertaken. For example, the quantity of air emissions that may be released under each of the alternatives is predicted. However, without knowing the location of activities that may produce pollutants, the dispersion of the pollutants cannot be analyzed, nor can impacts on receptor populations be estimated. Similarly, the acres required to build new generating facilities are estimated, but no attempt is made to determine what land uses may be disrupted or enhanced by this construction. Impacts on air quality, water quality, thermal discharge, waste products, land use, and direct employment are predicted.

The environmental analysis involves the straightforward approach of multiplying an environmental impact factor by the projected generation or capacity associated with each energy resource. The environmental impact factors chosen are listed in Chapter 4, Table 4.1. The attached air, water, and solid waste emission tables are the source information for Table 4.1. Trace pollutants were summed for simplicity in the text presentations but are displayed in this appendix. The capacity and generation projections were modeled for each of Western's areas. The modeling approach is described in Chapter 4, Section 4.2; many of the model inputs are provided in Chapter 3. Capital costs, operations and maintenance costs, and capacity factors were obtained from the Electric Power Research Institute (EPRI 1989).

F.1 AIR QUALITY

Data were obtained from various sources and converted to consistent units of pounds per megawatt-hour (lb/MWh) for comparison. Generally, the sources presented the ratio of the amount of emission of a particular substance to the amount of fuel used to produce the emission. The following conversion was used to achieve the units of emissions per kWh of electricity generated: (lb emission/unit fuel) * heat rate / (Btu/unit fuel) where the heat rate was expressed as Btus per kilowatt-hour (Btu/kWh). The fuel units varied from gallons of oil to pounds of coal to standard cubic feet of natural gas. Common conversions were used to obtain lb/MWh. When a variable in the above equation was unavailable from one reference, an equivalent value was substituted from another reference.

Included in this comparison were calculations of emissions made from methods incorporated in documentation prepared by the Environmental Protection Agency (EPA 1985, 1986, 1990, 1991). The following sources of information were assumed in order to convert data from the EPA references to the desired units:

* NO. 6 Oil Boilers-heat rate and percent of sulfur from the U.S. Department of Energy (DOE 1983) as cited in Ottinger et al. (1990).
* Subbituminous Coal-percent of ash and heat rate from Fluor Daniel, Inc. (1991); percent of sulfur from the State of California (1992).
* Natural Gas-heat rate from DOE (1983).
* Lignite Coal-heat rate from Fluor Daniel, Inc. (1991).
* Municipal Solid Waste-heat rate from Public Service Commission of Nevada (1991).
* Wood Biomass-heat rate from Public Service Commission of Nevada (1991).

Also included in the comparison were values reported by the State of California Energy Commission (CEC 1992). The following sources of information were assumed in order to convert data from the CEC to desired units:

* Combined Cycle Gas Turbine-heat rate from Fluor Daniel, Inc. (1991).
* Gas and No. 6 Oil Boilers-heat rate from DOE (1983) as cited in Ottinger et al. (1990).
* Gas and Oil Boilers-heat rate and percent of sulfur from DOE (1983) as cited in Ottinger et al. (1990).
* Pulverized Coals-heat rate from Chernick and Caverhill (1989) as cited in Ottinger et al. (1990).
* AFB Coal-heat rate from Chernick and Caverhill (1989) as cited in Ottinger et al. (1990).
* Internal Combustion Engines-heat rate from Public Service Commission of Nevada (1991).
* Gas Combustion Turbine-heat rate from Fluor Daniel, Inc. (1991).

Table F11 was then constructed showing the maximum, minimum, and average values for each type of emission under each technology along with the number of references used in developing the information. In addition to those references listed above, data were obtained from Bradley, Watts, and Williams (1991); Gleick, Morris, and Norman (1989); Kinsey (1992); NWPPC (1991); and BPA (1992). Much of this data was used for comparison with other references. Using this data, choices were made for the purpose of environmental analysis. The following 10 general conditions were considered when choosing the factors:

1) Consistent sources used in calculations and consistent approaches used across technologies and emission types.
2) Limited choice.
3) Study focused on specific emission.
4) Conservative estimates used for controls and other values.
5) Results fell in the mid-range of estimates.
6) Calculated from EPA (1985, 1986, 1988, 1990, 1991) with known methods and assumptions.
7) High qualitative score, references were ranked on criteria such as credibility and date of publication.
8) No PM10 given (PM10 refers to particulates with a diameter of 10 microns or less).
9) Source included appropriate controls such as low-nitrogen oxide (NOx) burners or baghouses.
10) Historical data from an existing plant may have limited applicability but represents empirical data.

Values selected for use in this EIS are shown in Table 4.1 in Chapter 4. Most of the carbon dioxide numbers were chosen from a report to Congress (Bradley et al. 1991) that focused on these types of emissions. Special consideration was given to those numbers that were calculated from EPA (1985, 1986, 1988, 1990, 1991) because other sources may not have been clear in how the numbers presented were established. Maintaining consistency for emissions within the same generation technology and across all technologies was attempted.

F.2 WATER QUALITY

Water consumption numbers were developed primarily from DOE 1983. Sources other than DOE 1983 were used in two instances. For gasified coal reference material cited in Ottinger et al. (1990, p. 285) were adapted.
For natural gas-fired combined-cycle combustion turbines and simple-cycle combustion turbines, water consumption requirements were calculated using engineering estimates from Fluor Daniel, Inc. (1988). This source provided a consumption rate of 3.4 gallons per minute (gpm) per megawatt (MW) for a combined-cycle combustion turbine and 0.44 gpm/MW for a simple-cycle combustion turbine. This measure was converted to consumption per megawatthour. These units were converted from gallons to acre-feet. In the conversion, an availability factor of 0.65 was used for both technologies to compensate for the capacity factor and the tendency to use these technologies to meet load peaks. The equations are as follows.

Combined-Cycle Combustion Turbine:
(3.4 gpm/MW * 60 minutes/hour * 0.65 availability factor)/325,850.35 gallons/acre feet = 0.0004 acre feet/MWh.

Simple-Cycle Combustion Turbine
(0.44 gpm/MW * 60 minutes/hour * 0.65 availability factor)/325,850.35 gallons/acre feet = 0.00005 acre feet/MWh.

Table 4.1 in Chapter 4 shows water consumption for each of the resources assessed.

Estimates of water effluents were primarily taken from DOE (1983) and Fluor Daniel, Inc. (1991). Water effluents from each of the resource types assessed are shown in Table F.2.

F.3 THERMAL DISCHARGE

Thermal discharge estimates are taken from DOE (1983) and are shown in Table 4.1.

F.4 WASTE PRODUCTS

Table F.3 shows the data obtained for solid wastes resulting from the various technologies explored. These numbers were taken primarily from DOE (1983) and Fluor Daniel, Inc. (1991). Where possible, the Fluor Daniel, Inc. estimates were relied on to be consistent with the approach used for the air quality analysis.

F.5 LAND USE IMPACTS

The report by Shankle, Baechler, Blondin, and Grover (1992) addresses land use impacts, as well as employment effects. The multipliers used for land use are shown in Table 4.1 in Chapter 4. Land use impacts are treated as one-time events that occur when new capacity is added. Conservation activities were assumed to not result in land use impacts.

F.6 SOCIAL AND ECONOMIC

The analysis of construction and operations and maintenance employment impacts are based on a review of the literature and analysis conducted by Shankle, Baechler, Blondin, and Grover (1992). The multipliers presented in Table 4.1 in Chapter 4 came from this report. Construction employment is treated as a one-time event that occurs when new capacity is added or new conservation is acquired. For consistency with other impact presentations, the results are summed.

Operations and maintenance employment is on-going. These multipliers are applied to megawatt-hour figures to estimate annual impacts. Operations and maintenance estimates were not calculated for conservation resources.

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F.8 TABLES

TABLE F.1. Power Plant Air Emission Factors

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--------------------------------------------------------------------------------

       Natural
                                                              Oil Fired
  NGSP     Gas                                         ENG  Reciprocating
GEO Geothermal
         Steam
        Plants                                                      Engine

 Count Average      Max      Min  ChoiceReference  Count        Average    Max   Min Choice
Reference Count    Average      Max     Min  Choice Reference
     6843.1307     1220  304.392    1100     RTC       5       1114.228   1620   330   1620
Nevada     5   87.29133  309.589     1.2     160        FD
     50.006417 0.009224 0.002968 0.00527  EPA-PNL      6      1.338442 3.7485  0.01  0.557
Nevada     0
     73.090223      6.2 0.101464   4.832  EPA-PNL      6       26.91583   33.5 5.025  5.025
Nevada     0
     0                          0.01493 sum m,nm       2          2.293  2.293 2.293  2.293
Nevada     1       0.46     0.46    0.46   0.001  sum m,nm
     30.007205     0.01 0.002635 0.00263  EPA-PNL      2        3.24135 6.39450.0882
4   4.22688   20.639  0.0004   0.001      IEPA
     10.012299 0.012299 0.012299  0.0123  EPA-PNL      2        1.43325 1.9845 0.882
0
     50.257921  0.35139 0.084189   0.314  EPA-PNL      6        7.07325 8.5995   4.1   7.28
Nevada     0
     50.089052    0.293        0 0.00878  EPA-PNL      5         2.1147 3.3075   0.1  2.393
Nevada     0
     30.027006   0.0439  0.00878                       2           1.24   2.38   0.1
0
     1     0.1      0.1      0.1     0.1     IEPA      0
2        0        0        0
     20.009224 0.009224 0.009224                       2          1.535   2.28  0.79
0                 0        0
     0                                                 0
0
     0                                                 1           0.39   0.39  0.39   0.39
Nevada     1    39.1895   77.626   0.753 39.1895       DOE
     0                                                 0
3   0.166875     0.38  0.0201  0.0664    Nevada
     0                                                 0
1   0.100457 0.100457 0.10046 0.10046       DOE
     10.004937 0.004937 0.004937                       0
0
     0                                                 0
0
     0                                                 0
0
     0                                                 0
0
     0                                                 0
0
     0                                                 0
0
     0                                                 0
0
     0                                                 0
```

```
0
     0                                                   0
0
     0                                                   0
0
     0                                                   0
1    0.01135   0.0206  0.0021 0.01135       DOE
     0                                                   0
0
     0                                                   0
0
     0                                                   0
0
     0                                                   0
0
     0                                                   0
1     0.0515    0.103       0  0.0515       DOE
     0                                                   0
0
     0                                                   0
1    0.28625   0.5205   0.052 0.28625       DOE
                                        0                                                    0
0.44956

                                        0                                                    0
0


1.48E+07

--------------------------------------------------------------------------------
TABLE F.1. Power Plant Air Emission Factors, continued
--------------------------------------------------------------------------------

            Wood
           (from
                                                           Municipal
  WWFR      wood                                       MSW     Solid
6OIL    #6 oil                                         CC
       waste and
Boilers
          forest                                                   Waste
        residue)

 Count   Average     Max      Min Choice Reference Count   Average      Max     Min    Choice
Reference Count  Average      Max      Min   ChoiceReference  Cou
     5      3460    3550     3400   3400         FD     5    3356.2     3747    2770      3747
FD     8  1411.91     1780   452.64     1710       RTC
     8  0.6621233.406245    0.017 0.2588   EPA-PNL    11  3.611189      6.4    1.28    1.7769
EPA-PNL     8  15.2752     25.4   2.6076    13.95      DOE
     8  5.19193217.03123    0.234  4.832   EPA-PNL    11   5.98007        8    3.94    5.8154
EPA-PNL     8 3.402076      8.5  0.11808     1.62      DOE
     5    2.436     3.2     1.29 2.9337  sum m,nm     2     0.504    0.504   0.504    0.1718
sum m,nm     0                 0        0   0.068 sum m,nm
     3  0.539244    0.55 0.517732 0.5177   EPA-PNL     9  0.013753     0.020.010338    0.0103
EPA-PNL      5 1.923074     3.54    0.017    0.018  EPA-PNL
     1  2.4160822.416082 2.416082  2.416   EPA-PNL     7  0.186297    0.2070.161538    0.1615
EPA-PNL      2 0.058678   0.0675 0.049856     0.05  EPA-PNL
     7  48.73111      88      3.7     6.9   EPA-PNL    11  5.916154       16    1.87     3.553
EPA-PNL      5 0.299874    0.337 0.184932    0.328  EPA-PNL
     7  21.61812      75  0.08136  10.35   EPA-PNL    11  20.20668    77.94    0.05    0.6138
EPA-PNL      7 1.523977      2.8    0.572     1.51  EPA-PNL
     0                0        0                         3  12.49333    36.92    0.28
2 0.663546 1.071251  0.25584
     2      0.55    0.55     0.55   0.55    Nevada     2      0.55     0.55    0.55      0.55
Nevada      1     0.34     0.34     0.34     0.34     IEPA
     0                                                   0
2   0.2952   0.5412   0.0492
     0                                                   0
0
     0                                                   0
0
     0                                                   0
0
     0                                                   0
0
     1     2.469   4.352    0.586                        0
1   0.0371   0.0371   0.0371   0.0371 DOE-Char
     0                                                   3  2.12E-05 3.15E-054.73E-07  4.73E-07
FD     0
     0                                                   2  0.001807  0.003592.49E-05  2.49E-05
```

FD 1 5.24E-05 5.24E-05 5.24E-05 5.24E-05 DOE-Char
0 2 0.024016 0.04770.000331 3.31E-04
FD 1 0.000154 0.000154 0.000154 0.00015 DOE-Char
0 2 0.012184 0.02420.000168 1.68E-04
FD 1 3.62E-05 3.62E-05 3.62E-05 3.62E-05 DOE-Char
0 2 0.148525 0.295 0.00205 2.05E-03
FD 1 0.019666 0.019666 0.019666 0.01967 DOE-Char
0 0
0
0 0
1 0.00031 0.00031 0.00031 0.00031 DOE-Char
0 2 0.405795 0.806 0.00559 5.59E-03
FD 0
0 4 0.125127 0.290769 0.0012 1.20E-03
FD 1 5.76E-06 5.76E-06 5.76E-06 5.76E-06 DOE-Char
0 2 0.010523 0.02090.000145 1.45E-04
FD 1 3.62E-05 3.62E-05 3.62E-05 3.62E-05 DOE-Char
0 2 0.014148 0.02810.000195 1.95E-04
FD 1 0.001082 0.001082 0.001082 0.00108 DOE-Char
0 0
0
0 0
0
0 2 0.04058 0.08060.000559 5.59E-04
FD 1 0.000154 0.000154 0.000154 0.00015 DOE-Char
0 2 0.513525 1.02 0.00705 7.05E-03
FD 1 6.59E-05 6.59E-05 6.59E-05 6.59E-05 DOE-Char
0 2 0.020944 0.04160.000288 2.88E-04
FD 0
0 0
0
0 0.0176014
0.05866

0 0
0

TABLE F.1. Power Plant Air Emission Factors, continued

Wood
(from
Municipal
WWFR wood MSW Solid
6OIL #6 oil CC
waste and
Boilers
forest Waste
residue)

Count Average Max Min Choice Reference Count Average Max Min Choice
Reference Count Average Max Min ChoiceReference Cou
5 3460 3550 3400 3400 FD 5 3356.2 3747 2770 3747
FD 8 1411.91 1780 452.64 1710 RTC
8 0.6621233.406245 0.017 0.2588 EPA-PNL 11 3.611189 6.4 1.28 1.7769
EPA-PNL 8 15.2752 25.4 2.6076 13.95 DOE
8 5.19193217.03123 0.234 4.832 EPA-PNL 11 5.98007 8 3.94 5.8154
EPA-PNL 8 3.402076 8.5 0.11808 1.62 DOE
5 2.436 3.2 1.29 2.9337 sum m,nm 2 0.504 0.504 0.504 0.1718
sum m,nm 0 0 0 0.068 sum m,nm
3 0.539244 0.55 0.517732 0.5177 EPA-PNL 9 0.013753 0.020.010338 0.0103
EPA-PNL 5 1.923074 3.54 0.017 0.018 EPA-PNL
1 2.4160822.416082 2.416082 2.416 EPA-PNL 7 0.186297 0.2070.161538 0.1615
EPA-PNL 2 0.058678 0.0675 0.049856 0.05 EPA-PNL
7 48.73111 88 3.7 6.9 EPA-PNL 11 5.916154 16 1.87 3.553
EPA-PNL 5 0.299874 0.337 0.184932 0.328 EPA-PNL
7 21.61812 75 0.08136 10.35 EPA-PNL 11 20.20668 77.94 0.05 0.6138
EPA-PNL 7 1.523977 2.8 0.572 1.51 EPA-PNL
0 0 0 3 12.49333 36.92 0.28
2 0.663546 1.071251 0.25584
2 0.55 0.55 0.55 0.55 Nevada 2 0.55 0.55 0.55 0.55
Nevada 1 0.34 0.34 0.34 0.34 IEPA
0 0
2 0.2952 0.5412 0.0492
0 0
0
0 0
0

0 0
0
0 0
0
1 2.469 4.352 0.586 0
1 0.0371 0.0371 0.0371 0.0371 DOE-Char
0 3 2.12E-05 3.15E-054.73E-07 4.73E-07
FD 0
0 2 0.001807 0.003592.49E-05 2.49E-05
FD 1 5.24E-05 5.24E-05 5.24E-05 5.24E-05 DOE-Char
0 2 0.024016 0.04770.000331 3.31E-04
FD 1 0.000154 0.000154 0.000154 0.00015 DOE-Char
0 2 0.012184 0.02420.000168 1.68E-04
FD 1 3.62E-05 3.62E-05 3.62E-05 3.62E-05 DOE-Char
0 2 0.148525 0.295 0.00205 2.05E-03
FD 1 0.019666 0.019666 0.019666 0.01967 DOE-Char
0 0
0
0 0
1 0.00031 0.00031 0.00031 0.00031 DOE-Char
0 2 0.405795 0.806 0.00559 5.59E-03
FD 0
0 4 0.125127 0.290769 0.0012 1.20E-03
FD 1 5.76E-06 5.76E-06 5.76E-06 5.76E-06 DOE-Char
0 2 0.010523 0.02090.000145 1.45E-04
FD 1 3.62E-05 3.62E-05 3.62E-05 3.62E-05 DOE-Char
0 2 0.014148 0.02810.000195 1.95E-04
FD 1 0.001082 0.001082 0.001082 0.00108 DOE-Char
0 0
0
0 0
0
0 2 0.04058 0.08060.000559 5.59E-04
FD 1 0.000154 0.000154 0.000154 0.00015 DOE-Char
0 2 0.513525 1.02 0.00705 7.05E-03
FD 1 6.59E-05 6.59E-05 6.59E-05 6.59E-05 DOE-Char
0 2 0.020944 0.04160.000288 2.88E-04
FD 0
0 0
0
0 0.0176014
0.05866

0 0
0

TABLE F.1. Power Plant Air Emission Factors, continued

Simple

Atmospheric
CTNG Cycle IGCC Coal
AFBC Fluidized
Combustion Gasification
Turbines
Bed Coal

Count Average Max Min Choice Reference Count Average Max Min
Choice Reference Count Average Max Min ChoiceRefer
9 1117.954 1560 273.9 1390 FD 13 1904.95 2180 1664
1810 RTC 11 2003.408 2380 507.6 2150
9 0.0069820.0083 0.004572 0.009 FD 11 1.096709 3.7 0.113
0.66 FD 95% 11 5.195747 11.65765 0.7908 1.5 FD

9 1.63158 5.152 0.188 1.064 FD 12 1.538529 3.2 0.208
0.61 FD 12 3.294838 8.771388 1.32459 1.5

3 0.16 0.16 0.16 0.016 Nevada 7 0.038971 0.048 0.0048
0.048 FD 6 0.076367 0.1 0.0282 0.058596 sum
3 0.16 0.16 0.16 3 0.543667 1.6 0.014
3 0.544185 1.6 0.015 0.017556 N
0 0
1 0.04104 0.04104 0.04104 0.04104 N
8 0.933167 1.434 0.192 0.387 FD 7 0.107571 0.13 0.013
0.13 FD 7 0.834413 1.5 0 0.350892 N
9 0.099931 0.174 0.00762 0.06 FD 11 0.17688 1.5 0.0034

```
0.04         FD    11    28.57128      140      0.1      0.11
     1       0.10790.1079   0.1079                          0
1      4.4556   4.4556   4.4556
     3         0.24  0.24      0.24      0.24    Nevada     2         0.356    0.41   0.302
0.302     Nevada     1       0.325    0.325    0.325     0.325   Ne
     1       0.09960.0996   0.0996                          0
0
     3        0.056 0.056    0.056                          0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      6     1.52E-09 #######1.10E-10  1.80E-
09       FD     4    2.43E-06 4.90E-06 3.50E-09  4.80E-06   FD
     0                                                      6     1.82E-08 #######1.30E-09  2.20E-
08       FD     4    2.88E-05 0.000058 4.20E-08  5.70E-05   FD
     0                                                      6     1.45E-05 1.8E-05   1E-06  1.70E-
05       FD     5    0.075014    0.282 0.000034  4.60E-02   FD
     0                                                      6     1.52E-08 #######1.10E-09  1.80E-
08       FD     4    2.38E-05 0.000048 3.50E-08  4.70E-05   FD
     0                                                      6     4.13E-09 #######2.90E-10  4.90E-
09       FD     4    6.50E-06 0.000013 9.50E-09  1.30E-05   FD
     0                                                      6     5.58E-08 #######3.90E-09  6.70E-
08       FD     4    8.76E-05  0.00018 1.30E-07  1.70E-04   FD
     0                                                      6     1.72E-08 #######1.20E-09  2.00E-
08       FD     4    2.73E-05 0.000055 3.90E-08  5.40E-05   FD
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
4     2.27705      5.1   0.0039       5.1   FD
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
     0                                                      0
0
                                          0                                                  1.713E-
05                                                5.1463458

                                          0
0                                                        0

                                   3.29E+06
4.79E+06                                                4.79E+06
---------------------------------------------------------------------------------
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TABLE F.2. Power Plant Waste Water Emission Factors

FLUOR DANIEL, Inc.
1991.

	PULVERIZED COAL BOILER - 603 MW	FLUIDIZED BED COMBUSTOR -244 MW	GASIFICATION COMBINED CYCLE	SIMPLE CYCLE COMBUSTION TURBINE		COMBINED CYCLE COMBUSTION TURBINE	
	90% Sulfur Removal	70% Sulfur Removal	95% Sulfur Removal	Natural Gas Fuel Cases	Distillate Fuel Cases	Natural Gas Fuel Cases	Distillate Fuel Cases

		Cases	Cases				
	Base Case	Base	Waste Water Treatment	Water Injection	Water Injection	Selective Catalytic	Selective Catalytic
HEAT RATE	9393	10130	8976	12072	11457	<8546	<8323
WASTE WATER	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh
Waste Water	520	1200	270	45	44	510	510
TDS	2.6	5.80E+00	2.70E+00	2.27E-01	2.18E-01	2.55E+00	2.52E+00
TSS	0.0078	1.70E-02	1.10E-04	6.80E-04	7.00E-04	7.70E-03	7.60E-03
TOC		4.50E-02		1.80E-03	1.70E-03	2.00E-02	2.00E-02
BOD		1.20E-02		4.50E-04	4.40E-04	5.10E-03	5.10E-03
Total Hardness	0.33	7.30E-01		2.90E-02	2.80E-02	3.20E-01	3.20E-01
Constituents							
Calcium	0.1	2.20E-07	2.00E-03	8.80E-03	8.40E-03	9.90E-02	9.80E-02
Magnesium	0.019	4.30E-08	5.00E-03	1.70E-03	1.60E-03	1.90E-02	1.90E-02
Sodium	0.61	1.40E-06	1.90E+00	5.30E-02	5.10E-02	6.00E-01	6.00E-01
Bicarbonates	0.067	1.50E-07		5.90E-03	5.70E-03	6.70E-02	6.60E-02
Phosphates	0.0062	1.40E-08		5.50E-04	5.20E-04	6.10E-03	6.10E-03
Sulfates	1	2.10E-06		8.40E-02	8.10E-02	9.50E-01	9.40E-01
Sulfides							
Chlorides	0.066	1.50E-07		5.80E-03	5.60E-03	6.50E-02	6.40E-02
Silica as SiO2	0.012	2.70E-08	4.00E-03	1.00E-03	1.00E-03	1.20E-02	1.20E-02
Iron	0.00041	9.30E-10	1.70E-03	3.60E-05	3.50E-05	4.10E-04	4.10E-04
Copper	0.00012	2.80E-10	5.00E-06	1.10E-05	1.00E-05	1.20E-04	1.20E-04
Zinc	0.00033	7.30E-10	3.20E-04	2.90E-05	2.80E-05	3.20E-04	3.20E-04
Beryllium			7.40E-06				
Chromium			2.60E-06				
Manganese			1.60E-05				
Nickel			2.10E-05				
Vanadium			5.30E-06				
Pesticides							
Acid-Base Neutral Extract							
Arsenic							
Barium							
Cadmium							
Total Chromium							
Hexavalent Chromium							
Lead							
Mercury							
Selenium							
Silver							
Chlorine							
Total Trace Pollutants	1.88106	4.10594E-06	1.9130773	0.160826	0.154893	1.81895	1.80595
Liquid radioactive effluents	0	0	0	0	0	0	0
Ci/MWh							
Tritium							
Activation and fission products							

TABLE F.2. Power Plant Waste Water Emission Factors,continued

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WOOD WASTE AND FOREST RESIDUE	AGRICULTURAL RESIDUE	COGENERATION PLANT, #2 OIL BOILER	COGENERATION PLANT, #6 OIL BOILER	COGENERATION PLANT, NATURAL GAS BOILER	NATURAL GAS COMBUSTION TURBINE	COMBUSTION OF MUNICIPAL SOLID WASTE	GEOTHERMAL	
Cases	Cases	Standard Low NOx Combustor Cases	Standard Low NOx Combustor Cases	Standard Low NOx Combustor Cases	Cases	Cases	Cases	
Base	Waste Water Treating	No Steam Exported	No Steam Exported	No Steam Exported	Standard Low NOx Dry Combustor	Uncontrolled Emissions	Single Flash	Binary-Cycle
14800	17000	10650	10520	11020	8300		20080	12290
lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh

1400	5200	1120	1120	1120	540			
7.2	4.10E-06	5.58E+00	5.58E+00	5.58E+00	2.70E+00			
0.022	1.00E-07	1.68E-02	1.68E-02	1.68E-02	8.10E-03			
		4.40E-02	4.40E-02	4.40E-02	2.10E-02			
		1.12E-02	1.12E-02	1.12E-02	5.40E-03			
0.91		7.10E-01	7.10E-01	7.10E-01	3.40E-01			
0.28	4.10E-08	2.16E-01	2.16E-01	2.16E-01	1.05E-01			
0.053	1.00E-07	4.10E-02	4.10E-02	4.10E-02	2.00E-02			
1.7	4.00E-06	1.31E+00	1.31E+00	1.31E+00	6.40E-01			
0.19		1.46E-01	1.46E-01	1.46E-01	7.00E-02			
0.017		1.34E-02	1.34E-02	1.34E-02	6.50E-03			
2.7	8.80E-07	2.08E+00	2.08E+00	2.08E+00	1.00E+00			
0.18	2.80E-06	1.42E-01	1.42E-01	1.42E-01	6.90E-02			
0.033	1.60E-07	2.60E-02	2.60E-02	2.60E-02	1.20E-02			
0.0012		9.00E-04	9.00E-04	9.00E-04	4.30E-04			
0.00035		2.70E-04	2.70E-04	2.70E-04	1.30E-04			
0.00091		7.10E-04	7.10E-04	7.10E-04	3.40E-04			
5.15546	0.000007981	3.97628	3.97628	3.97628	1.9234	0	0	0
0	0	0	0	0	0	0	0	0

TABLE F.2. Power Plant Waste Water Emission Factors,continued

LANDFILL GAS Case Uncontrolled Emissions	PULVERIZED COAL BOILER Case Lignite Coal	KRAFT BLACK LIQUOR Case Flue Gas Emissions	CARBONATE FUEL CELL Cases Natural Gas	Coal Gasification	Nuclear
12200-20000				6869	10377
lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh	
200	590	1800	300	360	
1.30E+00	2.9	8.9	1.50E+00	1.80E+00	0.0056
6.90E-03	0.0088	0.027	4.50E-03	5.40E-03	
		0.069	1.20E-02	1.40E-02	
2.60E-01		0.018	3.00E-03	3.60E-03	
2.30E-01	0.37	1.1	1.90E-01	2.30E-01	
	0.11	0.34	5.80E-02	6.90E-02	
	0.022	0.053	1.10E-02	1.30E-02	
2.50E-01	0.69	2.1	3.50E-01	4.20E-01	0.0106
	0.076	0.23	3.90E-02	4.70E-02	
	0.007	0.021	3.60E-03	4.30E-03	
2.60E-03	1.1		5.50E-01	6.70E-01	0.022
		3.3			
4.40E-01	0.074	0.23	3.80E-02	4.60E-02	
	0.013	0.041	6.90E-03	8.30E-03	
3.10E-04	0.00047	0.0014	2.40E-04	2.90E-04	
3.70E-06	0.00014	0.00042	7.20E-05	8.60E-05	
3.70E-06	0.00037	0.0011	1.90E-04	2.30E-04	
5.20E-05					
1.70E-06					
1.50E-02					
2.40E-05					
3.00E-04					
7.50E-06					
2.20E-05					
9.40E-06					
7.50E-06					
1.90E-08					
3.70E-07					
1.70E-06					
					0.0008
0.708343589	2.09298	6.31792	1.057002	1.278206	0.0334
0	0	0	0		00.050017
					0.000017
					0.05

TABLE F.3. Power Plant Solid Waste Emmission Factors

FLUOR DANIEL

	PULVERIZED COAL BOILER - 603 MW	FLUIDIZED BED COMBUSTOR -244 MW	GASIFICATION COMBINED CYCLE		SIMPLE CYCLE COMBUSTION TURBINE	COMBINED CYCLE COMBUSTION TURBINE	WOOD WASTE AND FOREST RESIDUE	AGRICULTURAL RESIDUE	COGENERATION PLANT, #2 OIL BOILER	COGENERATION PLANT, #6 OIL BOILER
	90% Sulfur Removal	90% Sulfur Removal	95% Sulfur Removal Cases		Natural Gas Fuel Cases	Natural Gas Fuel Cases	Cases	Cases (mid-values selected)	Standard Low NOx Combustor Cases	Standard Low NOx Combustor Cases
	Base Case	Base Case	Uncontrolled Emissions	Zero Water Discharge	Water Injection	Selective Catalytic	Base	Base	No Steam Exported	No Steam Exported
HEAT RATE	9393	10150	8969	9059	12072	<8546	14800	17000	10650	10520
SOLID WASTE 1										
Ash	30	45	87							
CaSO4										
Sulfur		1.6								
Metals										
Beryllium	3.50E-06	1.60E-06	0.000065							
Chromium	3.60E-05	1.90E-05	0.00078							
Manganese	2.90E-02	1.50E-02	0.62							
Nickel	3.10E-05	1.50E-05	0.00065							
Uranium	8.20E-06	4.20E-06	0.00018							
Vanadium	1.10E-04	5.70E-05	0.0024							
Zinc	4.50E-05	1.70E-05								
Aluminum										
Antimony										
Barium										
Cadmium										
Calcium										
Cobalt										
Copper										
Iron										
Lead										
Lithium										
Magnesium										
Mercury										
Potassium										
Sodium										
Silver										
Tin			0.00074							
Total Metals	0.029234	0.0151138	0.624815	0	0	0	0	0	0	0
SOLID WASTE 2										
Mineral Compound										
Silicon Dioxide								180		
Alluminum Oxide								37		
Titanium Dioxide								2.1		
Ferric Oxide								21		
Calcium Oxide								95		
Magnesium Oxide								39		
Potassium Oxide								150		

	PULVERIZED COAL BOILER - 603 MW	FLUIDIZED BED COMBUSTOR -244 MW	GASIFICATION COMBINED CYCLE		SIMPLE CYCLE COMBUSTION TURBINE	COMBINED CYCLE COMBUSTION TURBINE	WOOD WASTE AND FOREST RESIDUE	AGRICULTURAL RESIDUE	COGENERATION PLANT, #2 OIL BOILER	COGENERATION PLANT, #6 OIL BOILER
	90% Sulfur NOx Removal Combustor Cases	90% Sulfur NOx Removal Combustor Cases	95% Sulfur Removal Cases		Natural Gas Fuel Cases	Natural Gas Fuel Cases	Cases	Standard Low Cases (mid-values selected)	Standard Low Cases	
	Base Case	Base Case	Uncontrolled Emissions	Zero Water Discharge	Water Injection	Selective Catalytic	Base	Base	No Steam Exported	No Steam Exported
Sodium Oxide								26		
Sulfur Trioxide								0.19		
Phosphorous Pentoxide								27		
Strontium Oxide								0.63		
Barium Oxide								0.25		
Manganese Oxide								0.88		
Undetermined								57		
Total compounds	0	0	0	0	0	0	0	636.05	0	0
SLUDGE EMISSIONS										
Crystallizer Residue				0.2						
Constituents										
Calcium				9.00E-03						
Magnesium				1.00E-01						
Sodium				1.00E-01						
Silica as SiO2				1.00E-02						
Iron				3.00E-03						
Copper				4.50E-05						
Zinc				5.40E-03						
Beryllium				1.20E-05						
Chromium				4.40E-06						
Manganese				2.70E-05						
Nickel				3.50E-05						
Vanadium				8.80E-06						
Total Sludge	0	0	0	0.427532	0	0	0	0	0	0
Nuclear .Waste:	0	0	0	0	0	0	0	0	0	0
Low-level solid radioactive wastes: ft*3/MWh										
Wet material embedded in concrete										
Dry material in drums										
Water filtration										

waste products: lb/MWh aluminum hydroxide settled solids

TABLE F.3. Power Plant Solid Waste Emmission Factors, continued

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COGENERATION PLANT, NATURAL GAS BOILER	NATURAL GAS COMBUSTION TURBINE	COMBUSTION OF MUNICIPAL SOLID WASTE	GEOTHERMAL	LANDFILL GAS	PULVERIZED COAL BOILER	KRAFT BLACK LIQUOR	CARBONATE FUEL CELL	Nuclear
Standard Low NOx Combustor Cases	Cases	Cases	Cases	Case	Case	Case	Cases	
No Steam Exported	Standard Low NOx Dry Combustor	Dry Scrubber and Fabric Filter	Single Flash	Uncontrolled Emissions	Lignite Coal	Flue Gas Emissions	Natural Gas	
11020	8300		20080	12200-20000				10377
		1054			130			
		0.23			3.90E-04			
		0.54			6.10E-04			
		891			7.90E-05			
		3.23			7.90E-04			
		37.2						
		0.19						
		0.71						
		0.04						
		40.7						
		0.01						
		1.45						
		9.55						
		1.37						
		0.01						
		6.63						
		0						
		5.46						
		18.7						
		0.01						
		0.08						
0	0	1017.11	0	0	0.001869	0	0	0
0	0	0	0	0	0	0	0	0

COGENERATION PLANT, NATURAL GAS BOILER	NATURAL GAS COMBUSTION TURBINE	COMBUSTION OF MUNICIPAL SOLID WASTE	GEOTHERMAL	LANDFILL GAS	PULVERIZED COAL BOILER	KRAFT BLACK LIQUOR	CARBONATE FUEL CELL	Nuclear
Standard Low NOx Combustor Cases	Cases	Cases	Cases	Case	Case	Case	Cases	
No Steam Exported	Standard Low NOx Dry Combustor	Dry Scrubber and Fabric Filter	Single Flash	Uncontrolled Emissions	Lignite Coal	Flue Gas Emissions	Natural Gas	
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0.0278

0.009

0.0016

0.0096

0.0076

APPENDIX G Response to Comments

Appendix G contains a summary of the comments Western received on the Draft EIS and Western's responses to those comments. These comments were solicited through a 45-day comment period during which eight public meetings were held to explain the conclusions drawn in the Draft EIS and to take comments. Meetings were held on April 12, 1994 in Albuquerque, N.M.; April 18, Salt Lake City, Utah; April 19, Sioux Falls, S.D.; April 20, Sacramento, Calif.; April 22, Denver, Colo.; April 25, Phoenix, Ariz.; April 28, Fargo, N.D.; and May 1, Ontario, Calif.
Western notified the more than 5,000 individuals and organizations on its Program mailing list of the availability of the Draft EIS and the public comment meetings. A mailing also included a copy of the 16-page executive summary from the Draft EIS. Western subsequently provided more than 1,000 copies of the Draft EIS to interested people. More than 130 people attended the eight meetings with many making oral comments. Western received 210 written comment letters on the Draft EIS. Western analyzed the comments received and considered them in preparing the Program proposal published in the Federal Register on August 9, 1994 (59 FR 40543). Many of the comments addressed the same issues. A number of letters noted agreement and support for comments submitted by others. Because of the duplication of comments, references to other comments and in an effort to conserve resources, Western chose to address the issues in a summary instead of preparing responses to each individual comment. The identity of each commenter is set forth in parentheses at the end of each numbered comment in the appendix. A summary of comments received on the Program during the entire process and Western's responses were included in the proposed Program notice to help the public understand Western's rationale for its proposal. Including a copy of each letter and Western's individual responses would add unneeded bulk to this EIS. A copy of all the comment letters received is available for review at Western's Headquarters and area offices. The original correspondence is part of the official record.
Comments on the Draft EIS focused on these topics: resources and rates modeling capabilities, environmental benefits of the proposed program, treatment of demand-side management, air emissions, treatment of renewable resources, costs of integrated resource planning, treatment of environmental externalities, fuel costs, compliance with NEPA, generating plant capacity, Western and customer resource decisions, length of contract term extensions, EIS process and scope, use of the resource pool, energy efficiency requirements, and program scope.

Comment 1 - modeling approach: Agrees with aggregated simulation in the draft EIS, as opposed to system specific approach; agrees with general trend of the model results, although skeptical about some of the model's conclusions/extrapolations. Subregional environmental effects have not been adequately addressed (Midwest Electric Consumers Association; Platte River Power Authority).

Response: Because of the size and complexity of Western's service region, an aggregated approach was determined to be most appropriate in analyzing such a broad program. Because of its aggregate nature, the analysis tends to treat each Western area as a whole. No one utility system is represented and more of an area-wide average is assessed. This scale captures the diversity in resources, loads, and trends represented across Western's areas while avoiding many of the data requirements that would be needed to model individual utility systems and then aggregate up to a regional level. Data requirements to analyze individual utility systems would have required access to proprietary information, added tremendously to the expense and schedule of the analysis, and may not have provided more credible results.
The regional approach was especially important for environmental effects. Without knowledge pertaining to where specific powerplants would be located and then developing analysis of each site, Western cannot predict how the program will affect specific localities. This level of analysis will be left to those developing and siting the projects.

Comment 2 - projection of environmental benefits: Environmental benefits displayed in 2015 would continue to grow if analyzed for the full 25-year contract term. Environmental trends would be stronger if the impact analysis were extended out to 2025. (Midwest Electric Consumers Association; Granite Falls; Orange City; Paullina).

Response: The simulation of the utility system was run to the year 2030. Results, including estimates of environmental impacts, were reported for the study years 1995, 2005, and 2015. The results reported for the study years identify all trends that the utility system simulation identifies through its entire projection. However, as the projection continues into the future, the uncertainty associated with the results becomes more pronounced. Assumptions about economic performance, fuel costs, and other key factors become less reliable the farther into the future we attempt to forecast. The time horizon encompassed by the study years is consistent with utility industry standards for long-range plans and provides the most reasonable estimates of potential effects.

Comment 3 - environmental benefits understatement: Environmental benefits are understated by Western as the "no action" alternative predicts reliance on combustion turbines and combined-cycle combustion turbines in the future. This is unlikely, as coal is certain to be part of the resource picture in the future (Midwest Electric Consumers Association).

Response: Based on industry estimates of capital and operating costs for alternative technologies, the utility system analysis concluded that few new coal plants would be constructed over the simulation period. This conclusion may be false for specific utility systems that have different costs than those assumed or calculated. Sensitivity analyses on various fuel price assumptions revealed little impact on the resources for the BAO region (Kavanaugh et al. 1994). Nevertheless, were coal plants avoided, rather than natural-gas-fired combustion turbines and combined-cycle combustion turbines as projected, the environmental benefit could be greater than estimated, all other things held equal.
As noted on page 92 of the draft EIS, coal-fired generation is still the dominant source of power throughout the simulations. For instance, coal still accounts for half of the installed capacity in the BAO region. The dominance of coal portrayed in Figure 4.6 is belied somewhat because it is showing capacity. The role of coal-fired generation, because of baseload operation, is even more pronounced in the RRIM simulations. The load/resource balance conditions that evolve over time in the RRIM reflect more peaking requirement additions than baseload for the entire BAO region, as well. Within this aggregate, there may be some systems that reflect different requirements and that may deviate somewhat from this composite view. The RRIM results for the BAO region definitely reflect a continued, major role for coal.

Reference: Kavanaugh, D.C., D.M. Anderson, P.J. Barton, K.F. Gygi, C.D. McGee, W.H. Monroe, L.J. Sandahl, K.K. Tyler, G.A. Wright, AES Corp. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas. PNL-8721, Pacific Northwest Laboratory, Richland, WA.

Comment 4 - demand-side management - customer accomplishments: Energy management and DSM practices by Western's customers have been considerable. Energy efficiency accomplishments are not sufficiently recognized. Conservation efforts are well under way in the region, as shown in the Mid-West/MBSG "Conservation Database." Existing DSM achievements need to be documented in accordance with the attached MECA/MBSG database. The draft EIS does not include peak demand measures and needs to take into account past DSM efforts. The draft EIS did not use reliable baseline data when determining the potential for DSM/conservation in Pick-Sloan. The draft EIS is in error in suggesting that limited DSM activity is taking place in Iowa. Many utilities are presently complying with the majority of Western's proposals. OPPD and its customers are already implementing cost-effective DSM programs. The history of activities by Western's customers documents efficient/wise use of energy (Tri-County Electric Association; Verendrye Electric Cooperative; East River Electric Power Cooperative; Central Montana Electric Power Cooperative; Cooperative Power; Missouri Basin Municipal Power Agency; Woodbine; Moorhead; Sioux Center; Vermillion; Shelby; Breckenridge; Big Stone City; Wadena; Barnesville; Pierre; Detroit Lakes; Hartley; Beresford; Manilla; Burke; Lakefield; Jackson; Lakota; Northwest Iowa Power Cooperative; Ida County Rural Electric Cooperative; Monona County Rural Electric Cooperative; North West Rural Electric Cooperative; Basin Electric Power Cooperative; Corn Belt Power Cooperative; Sheyenne Valley Electric Cooperative; Southwestern Minnesota Cooperative Electric; Whetstone Valley Electric Cooperative; Redwood Electric Cooperative; Cherry-Todd Electric Cooperative; FEM Electric Association; Douglas Electric Cooperative; Intercounty Electric Association; Midwest Electric Consumers Association; Charles Mix Electric Association; Union County Electric Cooperative; Spink Electric Cooperative; Kingsbury Electric Cooperative; Northern Electric Cooperation; Lake Region Electric Association; REE Electric Cooperative; Beadle Electric Cooperative; Sioux Valley Electric; Renville Sibley Cooperative Power Association; Nobles Cooperative Electric; Lyon-Lincoln Electric Cooperative; Lincoln-Union Electric Company; Bonne Homme Yankton Electric Association; Traverse Electric Cooperative; Codington-Clark Electric Cooperative; Oahe Electric Cooperative; H-D Electric Cooperative; Minnesota Valley Cooperative; Lyon Rural Electric Cooperative; Oliver-Mercer Electric Cooperative; Plymouth Electric Cooperative; RSR Electric Cooperative; Runstone Electric Association; Federated Rural Electric; Central Power Electric Cooperative; Nebraska Public Power District; Woodbury County; Litchfield; Tri-State Generation and Transmission Association).

Response: For our analysis, energy efficiency is classified in three ways: 1) legislative mandates that regulators must implement and enforce, 2) voluntary adoption of measures by end-users, and 3) utility-sponsored or co-sponsored conservation programs. The estimates of DSM activity included in the utility system analysis accounted for all three types of activity.

The EIS states the assumption that, on average, under the No-Action Alternative, Western customers in the Billings, Loveland, Salt Lake City Area Offices invested in programmatic conservation measures at a cost up to 20 mills per kWh. As a result of IRP activity, we assumed that these investment levels rose to 35 mills per kWh. The assumption for the Phoenix and Sacramento area offices is 45 mills for the No-Action Alternative. We assumed that these investment levels rose to 50 mills per kWh.

These programmatic investments, along with legislative and voluntary activities, were estimated in 2015 to result in the following percentages of contributions to energy resource needs for customers in each area office under the No-Action Alternative: Billings 6 percent, Loveland 10 percent, Phoenix 16 percent, Sacramento 13 percent, and Salt Lake City 10.5 percent. The analysis found the following further reductions in energy usage under Alternative 8: Billings 10.5 percent, Loveland 13 percent, Phoenix 6.7 percent, Sacramento 9.5 percent, and Salt Lake City 14.8 percent.

The assumed investment levels have remained the same for the final EIS. However, model improvements have resulted in new estimates of resource contributions from conservation in each area office. Under the No-Action Alternative, conservation resulted in the following portions of energy resources: Billings 6 percent, Loveland 10 percent, Phoenix 13 percent, Sacramento 14 percent, and Salt Lake City 11.5 percent. Alternative 8 would result in the following additional reductions in energy usage: Billings 9.4 percent, Loveland 14.8 percent, Phoenix 4.9 percent, Sacramento 6.9 percent, and Salt Lake City 13.9 percent.

In determining the merits of the assumed investment levels, we reviewed the literature to determine if better estimates were possible. This review included the survey of member utilities completed by the Mid-West Electric Consumers Association and the Missouri Basin Systems Group, the survey completed by Basin Electric Power Cooperative titled Cooperative Conservation and Energy Efficiency Programs, and the many summaries of DSM activities received from reviewers. Both surveys and the summaries were cited in the comments on the draft EIS. Based on this information we revised the EIS to better explain the efforts underway in the Billings Area Office. The comments presented impressive information about the types of individual utility-sponsored activities under way. We also concluded that there is no better broad-based statistical information available to suggest that the investment assumptions should be changed.

One strong influence on the contribution of DSM is the rate of building new structures. In comparing the Area Offices, the F. W. Dodge building database reflects comparatively slower rates of historic and new building additions in the Billings, Loveland, and Salt Lake City areas than in the Phoenix and Sacramento areas. As a consequence, the model used for the utility system analysis shows relatively less building efficiency gains for regions where new additions or building stock growth is slower. Coupled with an inherited stock that is of an older vintage on average, building energy efficiency would be less. Additional information on building codes is presented later in this response.

The voluntary adoption of measures is market driven. The analysis includes this type of response to price in its assessment of the alternatives. Past activities reflect the relatively abundant and inexpensive power in the Billings, Loveland, and Salt Lake City area offices. See Tables 3.15 and 3.16 in the EIS for further information about the relative costs of power across the areas.

Energy Information Administration Sources

One reviewer specifically referred to data from the Energy Information Administration's 1989 Commercial Building Characteristics (CBC) (EIA 1991) to question the assumption that there are relatively fewer existing energy-efficient buildings in the Billings area. The reviewer noted that an entry on p. 106 of the CBC showed that commercial buildings in the Midwest with roof insulation consumed less electricity per square foot (13.2 kWh) than any other region in the country.

This comment raises the valid issue of the applicability of data from the CBC. However, we believe the reference intended was for p. 106 of the Energy Information Administration's Commercial Buildings Energy Consumption and Expenditures 1989 (CBECE) (EIA 1992a). Thus, we discuss the applicability of data from both the CBC and the CBECE.

The information referenced in the comment (from p. 106 of the CBECE rather than from the CBC) is a good example of determining suitability. The data show that for buildings that have installed roof or ceiling insulation, electric energy intensity is 13.2 kWh/sq. ft. in the Midwest. The finding for the West is 15.5 kWh/sq. ft.

These numbers must be viewed along with their relative standard errors (RSE). The RSE is calculated for any given cell in the tables by multiplying the row RSE, shown in the right column, by the column RSE shown in the top row under the headings. The RSE is described as"...a measure of the reliability or precision of a survey statistic. The RSE is defined as the standard error of a survey estimate, expressed as a percent of the estimate. For example, an RSE of 10 percent means that the standard error is one tenth as large as the survey estimate (EIA 1992a p. 462)."

For the Midwest result, the RSE is 7.2 percent. This means the result is accurate to within 7.2 percent. The resulting range for the Midwest number is 12.2 to 14.2 kWh/sq. ft. For the West, the RSE is 8.44 percent. The resulting range for the West is 14.2 kWh/sq. ft. to 16.8 kWh/sq. ft. Qualitatively it appears that the Midwest numbers show less electricity consumption per square foot of space. However, the comparison is within the range of standard error, which makes it difficult to draw a definitive conclusion.

There are two additional considerations. The first pertains to the applicability of the CBC and CBECE. The data in these documents are arranged by census region. These regions fit poorly with the boundaries of Western's Area Offices, making it difficult to interpret as published.

The Midwest region, as referenced in the comment, includes 12 states, five of which are

outside Western's service territory and include major population centers. These non-relevant states include Wisconsin, Illinois, Michigan, Indiana, and Ohio. Where entries are broken out into the West-North Central division of the Midwest, the states have a closer match but still include mismatches with the Billings area, such as the inclusion of Missouri and Kansas, all of Iowa and Minnesota, and none of Montana. This problem is exemplified by the results for electricity consumption and conditional energy intensity in buildings heated with electricity. For all buildings heated with electricity, the Midwest is found to have the greatest national consumption at 19.4 kWh/sq. ft. However, the West-North Central division of the Midwest is found to have 16.0 kWh/sq. ft. when considered by itself. Further differentiation is not possible using this publication.
Similar problems arise for the West region, which includes the following areas outside of Western's service territory: Alaska, Hawaii, Oregon, Washington, Idaho, and part of Montana.
The second consideration is that the analysis in the EIS is based on more than the comparative energy-efficiency of existing building stocks across Area Offices. The analysis is also based on the ratio of new to older buildings, the rate at which new buildings are being constructed, and the energy-efficiency of these new buildings. This issue is described above in the discussion of the F. W. Dodge database.
The reviewer also suggests that data from the EIA's Household Energy Expenditures 1990, (EIA 1993a) does not support the assumed differentiation between the Area Offices. The page numbers referenced by the reviewer (p. 106 and pp. 292-293) do not seem applicable. For purposes of the EIS analysis, this document has the same limitations and incompatibilities as the commercial studies discussed above. This finding also applies to the following reports, which were reviewed for applicability:

* Energy Information Administration (EIA), Office of Energy Markets and End Use. 1992b. Housing Characteristics 1990. U.S. Department of Energy, Washington, D.C.
* Energy Information Administration (EIA) Office of Energy Markets and End Use. 1993b. Household Energy Consumption and Expenditures 1990, Supplement: Regional. U.S. Department of Energy, Washington, D.C.

Other Data Sources

Data from the Electric Power Research Institute's 1992 Survey of Electric Utilities surveyed participation in utility DSM programs (PRI and SCI 1993). The EPRI study reports findings for participation rates across a number of regions. The Western region includes most of California, a portion of Nevada, Arizona, part of New Mexico, Colorado, the eastern part of Wyoming, and the southwest corner of South Dakota. The West-Central region includes an eastern slice of Montana, North Dakota, the remainder of South Dakota, Nebraska, Iowa, Minnesota, Wisconsin, Michigan, Illinois, and part of Missouri. The regional definitions do not match those of the census data, nor are they aligned with Western's Area Offices. Because of the difficulty in aligning the results with Area Office boundaries, this study was not incorporated in the analysis.
Oak Ridge National Laboratory conducted national surveys of utilities to compare DSM investment levels and percentage reductions in retail sales (Hirst 1992 and 1993). Findings were reported by state and by federal region. This source had the most applicable regional reporting of any survey information reviewed because of its focus on investment levels and its reporting breakdown:

* In a survey of 363 investor-owned and public utilities nationally, utilities in California were shown to invest 1 to 2 percent of their revenues in DSM. Utilities in Nevada and Minnesota were shown to invest 0.7 to 1 percent. All other states in Western's service territory were shown to invest less than 0.7 percent.
* In a survey of 439 investor-owned and public utilities nationally, utilities in California, Nevada, and Montana were shown to have saved 0.7 to 1 percent of retail sales by DSM. All other states were shown to have saved less than 0.7 percent.
* By federal region, the West (California, Nevada, and Arizona) was shown to invest 1.7 percent of revenues in DSM. The North-Central (Montana, Wyoming, Utah, Colorado, North Dakota, and South Dakota) invested 0.3 percent of revenues in DSM. The Western region aligned fairly closely with a combination of the Phoenix and Sacramento area offices. The North-Central region captured much of the Billings, Loveland, and Salt Lake City area offices, but excluded Minnesota, Iowa, Nebraska, Kansas, and Texas.

A survey of 2,039 public power utilities conducted by the American Public Power Association in 1991 (APPA 1992) found that public utilities in general have been aggressive investors in DSM. For example, the findings state that public utilities represent 17 percent of electric industry expenditures on DSM but only 13 percent of total electric industry revenues. The survey found that 75 percent to 100 percent of respondents in California, Arizona, and Nebraska have DSM programs. The study found that 0 percent to 6 percent of respondents in Nevada, Montana, and New Mexico reported DSM programs. Fifty to 74 percent of the respondents in North Dakota, Minnesota, Wyoming, Utah, and Colorado are shown to have DSM programs. The study reports that 38 percent to 49 percent of respondents in South Dakota and Iowa are running programs. And 7 percent to 37 percent of the respondents in Kansas reported having programs.
Building Code Information
State building codes influence building practices and the installation of energy efficiency measures in new and remodeled structures. The Model Energy Code (MEC) was developed by the Council of American Building Officials (CABO) primarily for residential applications. Thus, states that adopt the 1992 MEC for commercial applications do not meet the commercial standard set by the American Society of Heating and Refrigerating Engineers (ASHRAE) in Standard 90.1 1989. The following, taken from a survey

completed for the U.S. DOE (1994), is a description of energy-related building codes for the Area Offices:

Sacramento and Phoenix Area Offices: California has a state-developed code that exceeds ASHRAE Standard 90.1 1989 and the 1992 MEC in terms of efficiency and scope. California uses state-developed codes for both the commercial and residential sectors, as contained in Title 24. Nevada residential and commercial codes meet the 1986 MEC but not Standard 90.1 1989 or the 1992 MEC. Arizona has state-developed codes that are voluntary and do not meet Standard 90.1 1989 or the 1992 MEC.

Salt Lake City Area Office: New Mexico, Texas, and Utah all enforce commercial building codes, but none of them meets or exceeds Standard 90.1 1989 for general applications. Texas uses Standard 90.1-89 as its commercial building code, but applies it to state-owned buildings only. Texas does not enforce a residential building code. New Mexico and Utah use the 1989 MEC for residential buildings, which meets the 1992 MEC.

Loveland Area Office: The three major states covered within LAO are Colorado, Kansas, and Wyoming. None of the states has either a commercial or residential building code that meets Standard 90.1 1989 or the 1992 MEC. There is no state-wide commercial building code in Colorado. Kansas enforces state-developed codes; however, these codes do not meet the Standard or the 1992 MEC. The state of Wyoming recommends using the 1989 MEC for residential buildings, but the code is not mandatory.

Billings Area Office: The states of Iowa, Montana, North and South Dakota, and Nebraska do not have a commercial building code that meets Standard 90.1-89. Minnesota has a state-developed code that exceeds Standard 90.1 1989 and the 1992 MEC. Montana also exceeds the 1992 MEC. Other states in the Billings area do not exceed the 1992 MEC.

References:

American Public Power Association (APPA). 1992. Demand-Side Management in Public Power: The Quiet Revolution. Washington, D.C.

Energy Information Administration (EIA). 1991. Commercial Building Characteristics 1989. U.S. Department of Energy, Washington, D.C.

Energy Information Administration (EIA). 1992a. Commercial Buildings Energy Consumption and Expenditures 1989. U.S. Department of Energy, Washington, D.C.

Energy Information Administration (EIA), Office of Energy Markets and End Use. 1992b. Housing Characteristics 1990. U.S. Department of Energy, Washington, D.C.

Energy Information Administration (EIA), Office of Energy Markets and End Use. 1993a. Household Energy Consumption and Expenditures 1990. U.S. Department of Energy, Washington, D.C.

Energy Information Administration (EIA), Office of Energy Markets and End Use. 1993b. Household Energy Consumption and Expenditures 1990, Supplement: Regional. U.S. Department of Energy, Washington, D.C.

Hirst, E. 1992. Electric-Utility DSM-Programs: 1990 Data and Forecasts to 2000. Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Hirst, E. 1993. Electric-Utility DSM-Program Costs and Effects: 1991 to 2001. Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Plexus Research, Inc. (PRI) and Scientific Communications, Inc (SCI). 1993. 1992 Survey of Utility Demand-Side Management Programs. EPRI TR-102193, Electric Power Research Institute, Palo Alto, California.

U.S. Department of Energy (DOE). 1994. Report to Congress, Building Energy Efficiency Standards Activities Conducted Pursuant to Title 1, Subtitle A, Section 101 of the Energy Policy Act (draft). EE-1167, U.S. DOE, Washington, D.C.

Comment 5 - air emissions: References to CO_2 as anything other than an emission should be deleted from the draft EIS (East River Electric Power Cooperative; Cooperative Power; Capital Electric Cooperative; James Valley Electric Cooperative; Lincoln).

Response: The final EIS refers to CO_2 as an emission.

Comment 6 - modeling assumptions: Retirement of generating units is overly simplistic and contains no information from utilities. In Figure 4.6 (p. 93), coal plant retirements are too aggressive. OPPD's coal-fired North Omaha Power Station has units approaching 40-years of operation with no plans for retirement in the near future. In fact, the units are expected to be available for at least 60-years. Western should reconsider the 30- to 35-year life assumption for existing coal-fired units. OPPD does not plan to retire its coal-fired facilities during the study period because of the high cost to build replacement capacity. OPPD recommends that existing coal-fired facilities not be retired during the study period unless Western has information from the power plant owner/operator that a retirement is scheduled or planned during the study period. In Section 3.2 (p. 36) a statement is made that "retired coal plants are likely to be replaced with other technologies." How was this determined? Does the RRIM model determine the most economic replacement? Were replacement coal-fired facilities considered? (Cooperative Power; Omaha Public Power District; Tri-State Generation and Transmission Association).

Response: As discussed in Section 3.7 and 4.2 of the final EIS, individual generating units are grouped into homogeneous classes, which form the basis for projecting the long-run capacity expansion paths for the Western regions. Such aggregation facilitated the ready use of generic data from the EPRI Technical Assessment Guide (TAG) (EPRI 1989).

One of the components of the cost and performance characteristics listed in the TAG is the unit life (in years) that is used by utility system planners in routine screening analyses. Because of the link between capacity/plant expenses and financial/rates computations, we used the EPRI TAG planning assumptions for the book life of plants. These covered the following: coal-fired steam - 30 years; combined cycle combustion turbine plant - 30 years; combustion turbines - 20 years; and renewable (non-hydro) technologies - 20 years. For the physical life of the units, longer lives were assumed to reflect, in part, life-extensions and refurbishments, and the unit indivisibility elements of larger, baseload types of capacity. The following were used in this regard: coal-fired steam - 100 years; combined cycle combustion turbine plant - 50 years; combustion turbine - 50 years; and renewables - 75 years. Thus, the physical retirement was extremely gradual over the initial 15 to 20 years of the Program simulations.
The RRIM model is based on conventional resource screening criteria for planned plant additions when existing installed capacity is insufficient to meet demand. It basically compares the capital and running cost of the different technologies and selects the least-cost one to meet the forecast-load duration curves over the planning period. Because of boundary solution and non-vortex solutions commonly associated with strict programming approaches, the model uses a probablistic model to help select the new technologies from the array of options that RRIM "constructs."

Reference: Electronic Power Research Institute (EPRI). 1989. The Technical Assessment Guide, Vol. 1, "Electricity Supply 1989." EPRI p-6587-6, Palo Alto, CA.

Comment 7 - renewable resources data: The amount of renewable generation does not appear to be accurate (Cooperative Power).
The draft EIS understates estimated projected use of wind energy. Table S.4, the 1995 expected capacity for wind energy is 1,600 MW. This is the present capacity for the Altamont facility alone. Two other California facilities, San Gorgonio and Tehachapi (both in the Phoenix marketing area), equal Altamont's output. Also, only minimal renewable generation is projected for 2015 (Bureau of Land Management).
Response: Tables S.4 and 4.1 have been corrected to reflect the information used in the analysis. The input assumptions for renewable energy were produced from a review of the literature that included a number of surveys of renewable potential in Western's service region. The review also included a number of interviews with experts at U.S. DOE laboratories and industry associations. Sources of information and assumptions are described in Appendix E of Kavanaugh et al. (1994).

Reference: Kavanaugh, D.C., D.M. Anderson, P.J. Barton, K.F. Gygi, C.D. McGee, W.H. Monroe, L.J. Sandahl, K.K. Tyler, G.A. Wright, AES Corp. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas. PNL-8721, Pacific Northwest Laboratory, Richland, WA.

Comment 8 - emission credits: The final EIS should also consider the effect of SO2 emission credits on customers. New allowances would have to be purchased from others, perhaps new customers. This cost and benefit go beyond the simple loss of a hydro allocation (Missouri Basin Municipal Power Agency).

Response: The issue of SO2 emission credits is complex and of enormous interest to owners of coal-fired power plants. A brief description of the issue is presented in Appendix A of the EIS. We do not believe further analysis of this issue would materially impact the trends predicted in the EIS. The analysis found that few additional coal-fired power plants will be constructed through the planning horizon. Coal-fired power plants are the key source of SO2 in the United States, although western coal is much less of a polluter than eastern varieties. The imposition of additional costs (for pollution-control equipment or to purchase credits) would not change the identified trends.

Comment 9 - Incremental DSM: The draft EIS prediction of 11.6 percent additional energy saving for
non-generating public utilities in the BAO in 2015 due to the Program is too high. Disagree with the Program forecast that our customers will use 5 to 15 percent less energy in 2015. The implementation of Western's Program will not increase customer investment in cost-effective DSM programs to the degree WAPA forecasts. OPPD and its customers are already implementing cost-effective DSM programs. The Program draft EIS estimates 5 to 15 percent energy savings through conservation efforts. This is above the projected national average (Missouri Basin Municipal Power Agency; Omaha Public Power District; Bureau of Land Management, Rawlins District).

Response: The surveys and other information submitted by Western's customers in the BAO demonstrates a history of active DSM activity, especially in the areas of load shaping. The results presented in the EIS represent a regional perspective of potential savings, even though specific utilities may have quite different circumstances. The results are not an attempt to establish goals or criteria for use in judging utility performance. Rather, the analysis is geared toward identifying trends useful in assessing environmental impacts. The predicted savings (11.6 percent in this instance) for the year 2015 are likely to be inaccurate when applied to any given utility. Specific utilities may find more or less savings, but probably will not hit the prediction.

Comment 10 - IRP costs: The cost of IRP understates monitoring and verification expense (Missouri Basin Municipal Power Agency; Granite Falls; Orange City; Paullina). Administrative costs of IRP estimated in the draft EIS do not appropriately recognize the cost of monitoring and evaluation (Midwest Electric Consumers Association).

Response: The focus of the analysis is the first-time cost of preparing an IRP. These estimates were compared with actual costs from Western customers to assure a reasonable range. Monitoring and verification incremental costs are likely to be even more variable than first-time IRP preparation costs. The increments will depend on the programs established as a result of the IRP, and the level of monitoring and verification. These costs will vary considerably among Western's customers.

Comment 11 - emission reference: All references to CO2 should be removed, since it is pure speculation that CO2 contributes to climate change (Basin Electric Power Cooperative).

Response: This issue is discussed in Appendix A of the EIS, which has been updated for the final EIS.

Comment 12 - air emissions - end-use technology: Some electrical end-use technologies are so efficient that a net reduction in CO2 takes place on their adoption. This is recognized in the Clinton Climate Change Action Plan. The National Academy of Science recommends increased efficiency of electricity use that will lower the real costs of electricity supply (Basin Electric Power Cooperative).

Response: Electric technologies have been shown to mitigate CO2 emissions as well as other environmental issues, such as hazardous waste production, and water effluent releases. The degree to which CO2 reductions occur depends on the technology being introduced, the technology being displaced, and the mix of power plants providing the electricity. Techniques for calculating CO2 emissions reductions are being developed by the U.S. DOE. For more information, see Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992 (DPE/PO-0020).

Reference: U.S. Department of Energy (DOE). 1994. Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992. DPE/PO-0020), U.S. DOE, Washington, D.C.

Comment 13 - environmental externalities: Western should remove the statement that is found on p. 50 (of the EIS) stating that neither the North Dakota nor South Dakota Public Utility Commission has awareness of environmental externalities (Mid-west Electric Consumers Association; Basin Electric Power Coorperative).

Response: The statement reads, "North Dakota and South Dakota are rated as none." In the EIS text the previous paragraph defines "none" as "the state has no rules or approaches for incorporating environmental externalities into utility planning, and there are no known plans for the state to develop such rules." Our intent was not to imply that these states have no awareness of these issues, only that these states do not intend to establish rules regarding these issues. Section 3.6 has been revised to be moreclear.

Comment 14 - DSM regulation: Table 3.9 appears to suggest that there is no DSM in North Dakota or South Dakota. The attached document, Cooperative Conservation Energy Efficient Programs, shows significant activity in this region (Basin Electric Power Cooperative).

Response: The table was intended to summarize state rules for DSM and IRP activities. These states do not have rules affecting DSM. Section 3.6 has been revised to be more clear.

Comment 15 - DSM projections: We are concerned that overly optimistic DSM participation levels are assumed for the future (Omaha Public Power District; Basin Electric Power Cooperative).

Response: Two key assumptions among a wide array of parameters in the DSM program design are those relating to participation rate and program ramping rates. All are subject to considerable uncertainty, especially for long-range resource planning simulations. At the regional level, the uncertainty may not be as comparable because of offsetting deviations, but for individual systems, deviations are likely to surface.
Program design parameters like these are held invariant across the No-Action and Program Alternatives, so differences in the Alternatives did not originate here. Some sensitivity analyses were conducted on RRIM (Kavanaugh et al. 1994) and showed stable outcomes.
Reference: Kavanaugh, D.C., D.M. Anderson, P.J. Barton, K.F. Gygi, C.D. McGee, W.H. Monroe, L.J. Sandahl, K.K. Tyler, G.A. Wright, AES Corp. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas. PNL-8721, Pacific Northwest Laboratory, Richland, WA.

Comment 16 - DSM inducement: Delete the statement on page 48, "Even if public utilities are not regulated directly, they may feel pressure to match the level of service provided by nearby private utilities. If investor-owned utilities develop aggressive DSM programs as a result of state requirements or their own planning, public utilities may follow suit to satisfy their customers." We would suggest it is the IOUs that are following or lagging behind, not the public utilities of North Dakota and South Dakota (Capital Electric Cooperative; James Valley Electric Cooperative).

Response: The statement has been clarified.

Comment 17 - fuel costs: Coal and natural-gas prices in Table 4.5 (p. 86) are too low. For 1990, OPPD's average coal and natural gas prices were 0.74 and 2.27 cents per mmBtu. We agree with the real escalation rates (Omaha Public Power District).

Response: The initial utility prices for gas supply have been updated (see Table 4.5 in the final EIS). As noted in Section 4.2 of the EIS, the values are not intended to be those of a specific system. They represent typical values based on historical data for broad regions spanning, in some cases, a number of large states. Individual values that differ from typical values listed in Table 4.5 can be expected, but the central tendency across all supplies should be reflected here.

Comment 18 - load growth assumptions: The BAO load growth assumptions for peak demand (1.0 percent) and net electricity use (1.0 percent) in Table 4.7 (page 91) are too low. OPPD's latest forecast, dated August 1993, projects a peak demand growth of 1.4 percent per year during the 1993-2017 time period. Net system requirements are projected to increase at 1.6 percent per year during this same period causing system load factors to improve. The April 1, 1993 MAPP Load and Capability Report forecasts peak demand to increase by 1.4 percent per year and energy to increase 1.9 percent from 1993 to 2002 (Omaha Public Power District).

Response: Peak demand and energy usage are determined within the RRIM from a broad array of assumptions about business activity, employment, fuel-price escalation, inflation and interest rates. Thus, load forecasts can differ due to a number of reasons, just one of which is the internal structure of the models. The time horizons of each of the forecasts differ somewhat, so it is possible that year-to-year differences in initial conditions and endpoints could also account for slight differences in forecasted rates of growth. The NERC-MAPP forecasts are a result of member utility submissions and for a ten-year period only. Further, a uniform methodology and a set of input assumptions across all the members is unlikely. Reconciling these two major sources of observed differences could narrow the resulting disparities further, although they are quite small.
Moreover, the effect on the impact analyses between the No-Action case and the Program Alternatives have been minuscule when the same adjustments are made to both groups of Alternatives. All things considered, the forecasts reviewed did not indicate large enough differences to warrant additional study. A discussion of the structural ingredients of the load forecasts can be found in Section 4.2 of the final EIS and in Chapter 3 of Kavanaugh et al. (1994).

Reference: Kavanaugh, D.C., D.M. Anderson, P.J. Barton, K.F. Gygi, C.D. McGee, W.H. Monroe, L.J. Sandahl, K.K. Tyler, G.A. Wright, AES Corp. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas. PNL-8721, Pacific Northwest Laboratory, Richland, WA.

Comment 19 - modeling results: Potential inaccuracies in the model may not be of a nature that would change the results. Do not redo any of the work on the draft EIS, as the process has gone on long enough. We have concerns about the draft EIS analysis, but do not favor prolonging the EIS process through lengthy revision of the study model (Cooperative Power; Midwest Electric Consumers Association; Nebraska Public Power District; Lincoln).

Response: As a result of comments received in the public review of the Program draft EIS, some updates and revisions to the RRIM assumptions and framework were made in support of the impact analysis for the final EIS. For a summary of the refinements, see Kavanaugh and Tyler (1994). These revisions did not prolong the EIS process. One such change was made in the presentation of the resource stacks shown in Figures 4.6 through 4.10 in the final EIS. The stacks were changed from the draft EIS to show nameplate capacity rather than capacity adjusted for availability or a capacity factor. In comparison with the draft, the final stacks tend to show larger capacity numbers. Further, the loads shown in the final stacks are net of interregional exports and imports. Another change refined the model's treatment of nonfirm energy and short-term firm energy. These changes tended to dampen the differences found between the alternatives, but improved the model's ability to account more realistically for energy that becomes available as a result of Western's actions.

Reference: Kavanaugh, D. C., and K. K. Tyler. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas: Supplement. Pacific Northwest Laboratory, Richland, WA.

Comment 20 - NEPA compliance: On page x of the summary and 80 of the report, there is a statement that should be clarified: "As specific resources are chosen, additional environmental analysis will be necessary. Western will complete these analyses for the resources that the Agency initiates, if any." We hope this statement does not indicate that this draft EIS is an ongoing process. This is a one-time process and should not be reinitiated until contract extensions expire. Evaluation of other options should be handled by the customer under the IRPs (Lincoln).

Response: The statement is an acknowledgement by Western that if the agency should develop resources, which it has no plans of doing, it will comply with NEPA and other applicable environmental laws. Western's customers and other developers will be responsible for analyzing environmental issues and complying with environmental federal, state and local laws for the projects they initiate. The statement has been clarified. There are further Western actions that will likely refer to the Program EIS. One example is the Sacramento Area Office's 2004 Power Marketing Program EIS. The Sacramento EIS will use the Program as a source of data and analysis, and may use elements of its alternatives in assessing the impacts of potential power marketing programs for the Central Valley Project. Other Western actions may draw on the Program EIS in this manner.

Comment 21 - DSM projections: Page x of the summary states, "The Phoenix and Sacramento areas were projected to experience less reduction because a substantial amount of conservation activity already exists there and is contained in the no action alternative. Billings, Loveland and Salt Lake City, where energy-efficient buildings make up a smaller portion of the building stock are predicted to have a larger potential savings." This seems to be contradicted on page 98 where the relative shares of DSM in the resource stack are discussed. Phoenix and Sacramento show 13 percent and 16 percent DSM for future resources options where Billings, Loveland, and Salt Lake City have 6 percent, 10 percent and 10.5 percent, respectively. If the model is picking economic DSM, then there is more economic DSM in Phoenix and Sacramento (Lincoln).

Response: The shares and associated narrative are updated and clarified in the final EIS. Note that the summary discussion of DSM's contribution to meeting energy-service demands is a comparison across Alternatives, not across regions in a given Alternative. In the baseline or No-Action Alternative, the percentage shares are as cited in the final EIS. However, the comparison discussed in the summary chapter is not across the Area Offices of Western in that Alternative. Rather, the increased role of DSM in BAO, LAO, and SLCAO areas is relative to the role of DSM in PAO and SAO. These results are largely from the differences in their respective building stocks. The increase in resource share accounted for by DSM investments in BAO, LAO and SLCAO is somewhat greater than what RRIM developed for PAO and SAO under the Program Alternatives.

Comment 22 - load control: It does not appear that the draft EIS assumed any load control. The only DSM options considered were for conservation. This seems to be overlooking a significant option that is being utilized extensively in this region. Eastern Division customers have done much, especially in load management. Much has been accomplished in the past regarding load control, efficient equipment, energy audits, weatherization loans, etc. Our history of activities documents efficient/wise use of energy (Lincoln; East River Electric Power Cooperative; Missouri Basin Municipal Power Agency).

Response: Traditionally, load management has occupied a collateral status with conservation in conservation and load-management resource options. Utilities customarily rely upon the following resource options to shed load during periods of peak demand: 1) interruptible rates to high load-factor/industrial customers; 2) voltage reduction; 3) cycling end-use applications like electric hot water heating; and 4) system efficiency improvements. Interruptible tariff structures are not modeled in the RRIM model, so that option is precluded. While the other utility load management options represent, in many instances, economical ways of meeting firm peak demands at high levels of reliability, presumably, such "system-side" efficiency/load management efforts would be invariant across all alternatives. The Program would be unlikely to cause any appreciable difference in response. Since the differential impacts would then be null, the complex representation of such activities in the existing RRIM model would produce little net influence on its outputs.

Comment 23 - fuel switching: Increases in the cost of power will lead to fuel switching and increase greenhouse gases (Cherry-Todd Electric Cooperative).

Response: The analysis captures changes in greenhouse gases resulting from fuel selection for power plants, but is not intended to capture emissions from end uses. Given the modest impacts on rates and the net effects on loads of all factors in the model, we conclude that fuel-switching at the end-use level would not alter the trends among the Program Alternatives.

Comment 24 - generating plant capacity: In Appendix E, p. 206, Kramer and Scottsbluff are listed as active plants and the capacity for several NPPD resources are listed incorrectly. Although we understand that these values may not have been directly used in the analysis, they should be correctly included in the final EIS using the current accredited capacity, For example, Cooper - 778 MW, Gentleman - 1278 MW, Sheldon - 225 MW, Canaday - 107 MW, Kingsley - 38 MW, Hallam - 50 MW, and McCook 49 MW. Kramer and Scottsbluff should not be included on the list (Nebraska Public Power District).

Response: Appendix E has been corrected to show the updated numbers for plants that are listed on the map (Figure E.1). The database shown in Appendix E was taken from Power Magazine (1991), from McGraw-Hill Energy Publications Group. As the comment indicates, the resource information presented in Table E.1 is for purposes of illustration to show the diversity and complexity of the electricity generation plants in the Western region. The actual input to the model was Western's Resource Database (1991), which reflects all the listed values. The database presented in Appendix E was used for quality assurance purposes in preparing the Western database for the analysis.

Reference: Western Area Power Administration. 1991. 1991 Resource Database. Western Area Power Administration. Golden, Colorado.
Power Magazine. 1991. "Electric Utility Generation Plants in Operation," (map) 6th ed., McGraw-Hill Energy Publications Group, New York.

Comment 25 - data annotation: Many of the basic elements used to develop data tables merit notation. The major source of data used to develop the spreadsheets is the 1985 EPA emissions data, which was replaced in 1993 for most criteria pollutants. We question the validity of regional data since table F.1 lists the minimum range (for SOx) at 0.449 while Rawhide Energy Station is 0.13 and Craig Station III is 0.20. The average pulverized coal emissions in Table 4.1 at 1.6 for 90-percent removal of SO2 seems high for western coal which is primarily subbituminous and lignite. Platte River's Rawhide station is 80-percent removal and SO2 emissions are 1.1 lbs/MWh. The data merits redevelopment since we understand that at least one entire 225 MW power plant (The Republican River Plant) was moved out of the United States in the 1980s.
There is missing data in the Appendix F tables, some of which has been in existence since 1989. For example, combustion turbines have emission factors in the EPA Air Toxic Pollutant Emission Factors Report which could have been incorporated in the Appendix tables. (Platte River Power Authority).

Response: See Appendix F for changes in the text to better explain Table F.1. The environmental impact factor for SOx emitted from pulverized coal plants chosen for the analysis was calculated by Fluor Daniel Inc., in 1991, as referenced in Appendix F. The EPA 1985 source was not selected for the analysis but was included in the comparison of 28 references used to evaluate generic factors that may be employed. Comparisons with any specific plant may yield substantial differences with the generic value because it must represent a broad variety of technologies, efficiencies and fuel sources.
The generic environmental impact factor used in the analysis for SO2 emissions from pulverized coal plants is 1.6 lbs/MWh. For comparison, the reviewer references 1.1

lbs/MWh as the actual emission level for a specific plant. Given the range of values included in the literature, these appear reasonably similar. To change the analysis substantively, the factor for a pulverized coal plant must change dramatically relative to the factors for other technologies. The factors for combustion turbines 0.009 and combined-cycle combustion turbines (0.006) are three orders of magnitude less than either factor for coal. Given these differences, we find the existing factors adequate for the analysis.
EPA 1985 is updated on a regular basis. For our calculations, the 1985 base material had been updated using the following supplements:
United States Environmental Protection Agency (EPA). 1986. Supplement A to Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. U.S. Government Printing Office, Washington, D.C.
United States Environmental Protection Agency (EPA). 1988. Supplement B to Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. U.S. Government Printing Office, Washington, D.C.
United States Environmental Protection Agency (EPA). 1990. United States Environmental Protection Agency (EPA). Supplement C to Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. U.S. Government Printing Office, Washington, D.C.
United States Environmental Protection Agency (EPA). 1991. Supplement D to Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. U.S. Government Printing Office, Washington, D.C.
The most recent update, Supplement F, was issued in July 1993. A new edition of the document is expected to be published in Spring 1995.

Although not derived from the EPA compilation, air toxics in the form of volatile organic compounds were included for combustion turbines. Air toxics were not included in the generic analysis because of their specificity in regard to plant design and specific fuel type. We expect that air toxics would follow the same trends as other air quality impacts in comparing the alternatives. Air toxics were first included in the EPA compilation in 1992.

Comment 26 - significance of impacts: The Environmental Consequences section in Chapter 4 conclude that "the reduction appears to be small" but "in absolute terms these reductions are important." We also feel that the SO_2, NO_x , TSP, and CO_2 incremental changes on pp. 107-110 are significant. The incremental change of nearly 10 million tons of CO_2 and even the 2.5 million tons difference between the non-extension and certain of the Extension Alternatives should be considered significant as applied to the President's Climate Change Action Plan. Similarly, several of the Extension Alternatives for Wastewater Production, Water Quality Impacts, Waste Thermal Discharge, and Land Use Impacts are significant (Platte River Power Authority).

Response: Significance can be judged in many different ways. We agree that the beneficial effects found in the EIS are important and significant in many respects.

Comment 27 - customer resource decisions: Western's short-term purchase decisions do not dictate the size, technology, timing, location, or fuel input of power plants constructed or planned by power producers. If the Western resource is to be stable, it must be stable through changing conditions. Demand exists if Western buys or the customer buys. There is no recognition in the draft EIS of the impact of extensions on purchases of thermal power; we do not take a position on whether it is appropriate for Western to purchase this much power, but only ask that the impacts be analyzed (Loveland Area Customer Association; Tri-State Generation and Transmission Association; Irrigation and Electrical Districts Association of Arizona; Land and Water Fund).

Response: We did not assess in the EIS analysis how varying Western's short-term purchases directly influence the environment. Western generally makes short-term power purchases to make up for shortfalls in hydropower production resulting from hydrologic conditions. The EIS analysis assumes water conditions that do not tend to encourage Western purchases (see Table 3.11 in the final EIS for a summary of planning criteria by region). To the extent that purchases are made within Western's region, the impacts are captured in the EIS estimates.
Decisions by Western's customers to construct new power plants or to enter into power purchase contracts are complex, requiring the analysis of many issues. Price and uncertainty are two key issues that may be influenced by Western's short-term purchases, if these purchases become too severe. Western's purchases can tend to increase the cost of its resources. Thus, if Western over-commits to its customers, or if hydrological conditions are extremely bad, Western's resource cost may change significantly.
However, if Western under-commits its resources or fails to meet its obligations, its customers may build plants or purchase power to make up for lost or uncertain Western resources. Either over- or under-committing its resources impacts the value of Western's resources and potentially degrades system efficiencies.
If Western set out to minimize purchases, rather than to maximize product value, its customers would make up for the lost resources. Some customers may prefer to make their own purchases, others may build new capacity. But these decisions are probably as dependent on the status of other contracts, capacity, and options (e.g., the availability of DSM), as on Western's actions. Customer actions may not be the same as those that

Western would make because of differing contractual obligations, system requirements, management objectives, and attitudes toward risk.

Sacramento is the only area where long-term purchases are an integral part of Western's resources. These purchases are related to Western's entitlements to portions of the California-Oregon Transmission Project and the Pacific Intertie. Utilization of these transmission assets are an ongoing element of the Sacramento Area Office's marketing planning. These power purchases are being assessed in an EIS currently under way for the Sacramento Area Office for power marketing activities after 2004.

The RRIM model used for the utility system analysis in the EIS has been enhanced for the final EIS to distinguish between short- and long-term purchases and to improve the analysis of these purchases.

Comment 28 - resource-specific approval: Approval of generating plant construction and operation is subject to licensing, siting, environmental and other regulations (Loveland Area Customer Association; Tri-State Generation and Transmission Association).

t is important to emphasize that power plant emissions are subject to New Mexico Air Quality Control Regulations (AQCR) under all the alternatives. In addition, power plants are subject to the 1990 Clean Air Act Amendments; including the Title IV program , designed to reduce acid rain, and the Title V operating permits program, which regulates and imposes fees on plants with air pollutant emissions greater than 100 tons/year (State of New Mexico Environment Department).

Response: Western agrees that decisions to build new power plants will include provisions for licensing, siting, and other environmental regulations. These decisions will be made by Western's customers or other power generators, but are not likely to include Western participation. All new and existing power plants must comply with Federal, state, and local environmental regulations.

Comment 29 - customer resource decisions: Splintering of Western's resources will cause new resources to be acquired by Western's customers (Loveland Area Customer Association; Colorado River Energy Distributors Association; Tri-State Generation and Transmission Association).

Response: In the EIS analysis we found that the loss of Western resources, either through reservation for a resource pool or lack of certainty, tends to result in the construction of new capacity and increased generation.

Comment 30 - refinement of impacts: Environmental results may need to be refined on a project-by-project basis (Arizona Power Authority; Tri-State Generation and Transmission Association).

Response: For purposes of this EIS, Western believes that results should continue to be presented on a region-wide basis. Further analysis of new power plants will result when those plants are planned, licensed and sited.

Comment 31 - generation data: While there is a great deal of detailed data available on fossil-fired generation, significant data are lacking for the alternative resources as shown in Table F1 on p. 238. Table 4.1 (p. 75) does not have complete data for such things as airborne water from cooling towers and ash from wood wastes biomass (Loveland Area Customer Association; Tri-State Generation and Transmission Association).

Response: The tables have been improved for the final EIS. However, generic emission factors are not consistently available for all technologies. Some issues are identified only with selected technologies. For example, airborne water from cooling towers is often discussed in the literature for nuclear power plants, but not for other generation types. The table does list thermal discharges, which may be either liquid or gas, and which may be emitted to either water or air.

The table has been corrected to show ash from wood biomass. We calculate that about 27.5 pounds of ash are produced for each MWh of generation. This number is calculated from information in DOE 1983, as follows:

* Plant capacity: 62 MW
* Assumed capacity factor: 80-percent (information in the reference document suggests a capacity factor of 92-percent. This was adjusted to industry norms)
* Ash production: 5,972 tons annually
* 62 MW * 0.80 * 8760 hours/year = 434,496 MWh per year
* (5,972 tons per year/434,496 MWh per year) * 2000 pounds per ton = 27.49 pounds per MWh

The addition of this environmental impact factor does not affect the outcome of the estimates of ash production resulting from the alternatives. Wood-fired powerplants are not included in the resources considered in the capacity expansion analysis.

Comment 32 - contract term: Longer contracts would ease power-supply planning (Intermountain Rural Electric Association).

Response: Longer contracts tend to reduce the uncertainty for utility planners.

Comment 33 - contract term: Longer contracts will aid in stabilizing river-flow patterns (Intermountain Rural Electric Association).

Response: All alternatives are neutral with respect to river and dam operations, even though some may offer Western more flexibility in responding to operational changes stemming from other actions or projects. Please see Section 2.2.3 of the EIS for additional information.

Comment 34 - rate impact of DSM: Rate increases will result from DSM implementation (Intermountain Rural Electric Association).

Response: The impacts of DSM on average retail rates are the outcome of a very broad array of factors that govern the demand and supply of electric energy services. The purpose of RRIM is to simulate both of these major components as realistically as possible and to conform with demand theory and conventional utility economics.
One view is that retail rates will rise in response to DSM programs because retail rates recover both capital costs and variable costs, but avoided production saves only variable costs. Thus, capital costs must be recovered from a reduced sales base. Rates must rise by definition to recover revenue requirements. The short-run view is overly restrictive in assessing DSM impacts, which require a broader longer-run perspective.
The system-dynamics orientation of the RRIM model treats capital costs as fixed in the short-run, but over the longer-term (10 years and beyond), all inputs become variable or only quasi-fixed. When a less restrictive view is taken in the long-run, conditions may exist for a given system (or even a composite of systems) where average rates may be unchanged or even reduced in response to DSM. Rates could still rise, depending again on the complex interactions of DSM program design within demand/supply balancing. The revised rate impact numbers in the final EIS reflect the possibility of mixed results: For some systems rates, we estimate an increase in rates for Alternatives with greater levels of DSM, but the effect on others is somewhat less. As indicated in the draft EIS and reported in the final EIS, the percentage differences in rates across selected Alternatives are not substantial, particularly given that they occur so far into the future.

Comment 35 - population trends: Population Trend Tables 3.8 and Figure 3.11 contain conflicting information. The estimates for load growth may be overly high due to this conflict (Intermountain Rural Electric Association).

Response: Figure 3.11 and Table 3.8 do not conflict. Figure 3.11 shows the current trend and projection of population for all states having any counties inside of the Western Service Area. Table 3.8 simply shows the 1992, point-in-time, breakdown of population across area office territories, compiled by summing the population of each county actually pertaining to a given area office. Summing the population column of Table 3.8 does not yield the 1992 point on the graph in Figure 3.11, because in some states, not all counties are in Western's territory. The population information shown was not used in load growth forecasting.

Comment 36 - EIS results: Results of the DEIS appear to be generally consistent with our expectations (Salt River Project).

No response required.

Comment 37 - externality values: Concerning the impact factors and externality costs in the DEIS, the factors and costs need to be consistently applied among the contractors on a regional basis (Metropolitan Water District of Southern California).

Response: The externality values presented in Section 2.1.1.1 are for information purposes only. Externality values are not applied to resources in the analysis for the EIS,

nor are they required for Western's customers' use.
The environmental impact factors presented in Table 4.1 are for purposes of analysis in the EIS only. The factors may be used by Western's customers if they deem them appropriate for their needs.

Comment 38 - DSM assumptions: The DEIS assumption of implementation of all conservation up to 50 mills is too high/not cost effective (Central Arizona Water Conservation District).

Response: Selecting a uniform program-implementation cost cap to apply over a wide range of utilities had to be done to perform the Program impact analysis. The selected values reflected a balance of information and judgment concerning marginal resource costs, fully allocated costs, and the fact that in some states, those utilities practicing DSM receive mandated cost credits for resource acquisitions (see section 3.6.1 of the final EIS). In some regions during the 1990s the threshold for conservation is as high as 55 mills for cost-effectiveness levels. The areas for which 50 mills was adopted were the ones where the base case presumed a 45-mill level. Thus, the 5-mill increment at these levels has a small impact on forthcoming DSM. However, the 5-mill increment served to preserve the Program's encouragement of a more balanced approach to DSM and generation resources within the IRP framework.

Comment 39 - contract term: We agree with the DEIS identification of Western-wide benefits if long-term contracts are signed; significant reductions in environmental impacts can be achieved if long-term contracts are put into effect in conjunction with IRP (Northern California Power Agency; Palo Alto; Department of Energy-Oakland Operations Office; Alameda).

Response: This comment is consistent with the EIS findings.

Comment 40 - contract term, environmental benefits: Environmental benefits may be far greater that the draft EIS suggests, as short- term extensions impact ability to borrow money and force hedging of bets on availability of Western resources through pursuit of low capital cost, high operating cost, environmentally impacting thermal resources. This results in a decreased commitment to renewables, which have higher fixed costs, and adverse impact on revenue requirements, which also discourages DSM investment. Long-term contracts encourage a long-term planning focus which equals environmental benefits. We concur with the draft EIS analysis of the impacts of resource certainty. Sound environmental reasons exist for long-term contracts to be consistent with the long-range time horizon needed for effective IRP. Utilities regularly make supply-side commitments of 30 years (Palo Alto; Redding; Department of the Navy; American Public Power Association).
A 100-percent extension should be granted to customers in full compliance with the Energy Management Program; thirty years is the minimum extension that should be considered due to beneficial environmental impacts. We support 25- to 30-year contracts on environmental grounds (Turlock Irrigation District; Plumas-Sierra Rural Electric Cooperative).
Response: Western cannot reserve power for potential new customer needs if contracts are extended at a 100-percent level for those entities that comply with the Program. Western realizes that the draft EIS predicts relativelygreater environmental benefits for contract terms in excess of 18 to 20 years. At the same time, an 18 to 20-year proposal has clear future environmental benefits over other alternatives with shorter extension terms. An even greater environmental advantage exists for 18 to 20-year future resource extensions under the Program as compared to the uncertainty and delays associated with a potential project-specific marketing plan approach. The 18 to 20-year contract term in the Preferred Alternative balances environmental benefits associated with resource certainty against the need for flexibility to respond to changing circumstances over time.
We used the formula presented in Section 4.2.3 to capture elements of uncertainty associated with contracts similarity with a large number of the Extension Alternatives in the Program, its impacts did not appear materially different in terms of resource expansion and costs/rates. The 100-percent extension of available project capability would hamper Western's ability to allocate Federally-produced power to new customers. The environmental effects of this scenario are presented in Figures 1 and 2.
For organizational impacts, preliminary analysis shows that existing customers would assess the 100-percent/35-year proposal to be favorable in terms of all organizational impacts categories, possibly the most favorable after the No-Action alternative. These categories are flexibility, equity, administrative burden, and risk and uncertainty. The favorable impacts are due to the long extension period and high percentage extension allocation. Customers indicated in the organizational impact analysis that long extension periods provide the certainty and stability that customers are looking for. On the other hand, they may limit Western's flexibility to function effectively in a constantly changing environment.
Existing customers would view the 70-percent/10-year proposal, due to the short extension period coupled with a very low extension percentage, as having by far the least desirable

organizational impacts compared with the alternatives. This would be true in all impact categories. Furthermore, customers indicated in the analysis that 10-year extensions may not be adequate for customers to prepare an effective IRP.

Comment 41 - contract term, environmental benefits: Add a 13th alternative of 98 percent to 100 percent, 35 or 40 years duration, to maximize customer stability and environmental benefits. Consider an alternative with a 10-year contract length and a 70-percent allocation of existing resources (Palo Alto; Arvin-Edison Water Storage District; Roseville; Land and Water Fund).

Response: Western has determined that the 70-percent/10-year alternative would not be reasonable for analysis in the final EIS. The 10-year contract term is already included in existing alternatives. The 70-percent allocation, with the remainder going into a resource pool, allows too much power to go unallocated because potential new customer loads do not require such a large allocation. Leaving the power unallocated would lead to unnecessary power supply dislocations and potential development of new, but largely unneeded, supply-side resources, defeating the purpose of IRP.
Elements of the 100-percent/35-year proposal are already present, although not in this combination, in the 12 alternatives modeled in the draft and final EIS. The Preferred Alternative is treated as a combination of Alternative 5 and 6 and was not modeled separately. The proposal does extend Western's percentage of resource extension from 98 percent to 100 percent. Adding a new alternative will do little to describe or change the environmental impacts already captured by the existing alternatives. However, for purposes of comparison, a summary of the utility and environmental effects of the two options is presented here.
A cursory analysis with the RRIM simulation model showed that the scenario that assumes a 70-percent extension with 10-year contract lengths results in more resource additions than any of the Program Alternatives. The capacity expansion paths for each region under this particular case are the closest of all to the No-Action Alternative. In addition, the RRIM runs revealed higher average system costs (and average or unit revenues at the retail level) for this scenario. In comparison with Program Alternatives, the greater level of capacity additions result in fewer environmental benefits for impacts associated with new plant construction, such as land use requirements, as shown in Figure 1.
Impacts resulting from the generation of electricity from the 10-year/70-percent extension scenario are very similar to the effects resulting from the Program Alternatives, although the trends identified in the EIS suggest that this scenario would result in fewer benefits. The analysis found the expected result in four of the five area offices. However, the large energy resource surplus in the Billings Area Office resulted in a contrary finding, large enough to offset the expected trends in the other areas.
The model treats the lost Western allocation (in this case 30 percent) as short-term firm power. Within the model, generating utilities view the short-term firm resulting from this scenario as a comparatively lower cost resource that they could use to meet loads in the short term. Thus, the RRIM runs uniformly reflect more displaced thermal operation as the percent extension amounts decrease. To the extent that Western's resources would actually be allocated to new or existing customers, the availability of short-term firm is an artifact of the assumption about the fate of unallocated Western resources in the resource pool. This artifact does not substantively alter the results until very large blocks of Western resources enter the short-term market and therefore does not affect the results of the analysis presented in the EIS.
A comparison of environmental effects based on the model results shows very similar impacts from generation (all positive) for all of the Program Alternatives and teh two proposed options. An example of these findings for SOx emissions are show in Figur

2. Howeve
, because of the influence of the assumption about the use of Western's unallocated resources, we anticipate that the effects of the 70-percent/10-year proposal would still be beneficial, but less so than the Program Alternatives.

The 35-year/100-percent extension scenario was also summarily examined with RRIM, and given its near similarity with a large number of the Extension Alternatives in the Program, its impacts didnot appear materially different in terms of resource expansio

and costs/
ates. The 100-percent extension of available project capabilty would hamper Western's ability to allocate Federally-produced power to new customers. The environmental effects of this scenario are presented in Figures 1 and 2.

For organizational impacts, preliminary analysis shows that existing customers would asses the 100-percent/35-year propsal to be favorable in terms of all organizational impacts categories, possibly the most favorable after the No-Action Alternative. Th

se categori
s are flexible, equity, administrative burden, and risk and uncertainty. The favorable impacts are due to the long extension period and high percentage extension allocation. Customers indicated in teh organizational impact analysis that long extension

eriods prov
de the certainty and stability that customers are looking for. On the other hand, they may limit

Western's flexibility to function effectively in a constantly changing environment.

Existing customers would view the 70-percent/10-year proposal, due to the short extension period coupled with a very low extensionpercentage, as having by far the least desirable organizational impacts compared with the alternatives. This would be ture

n all impac
categories. Furthermore, customers, indicated in the analysis that 10-year extensions may not be adequate for customers to prepare an effective IRP.

Figure a. Total SOx Emmissions

Figure b. Total SOx Incremental Change

Figure a. Total NOx Emmissions

Figure b. Total NOx Incremental Change

Comment 42 - natural gas projections: The draft EIS assumption of the prominent role of natural gas in the future may not be consistent with the DOE projection of gas production peaking in 2005 and declining thereafter (Plains Electric Generation and Transmission Cooperative).

Response: The role of gas-fired generation is not presumed; rather, it is derived from solving the RRIM equations. These RRIM runs are based partially on assumptions about the gas price delivered to utilities for generation and about the expected escalation in this cost over the planning period. This is true for all generation/fuel types, as well. As noted in the EIS, fuel price uncertainty is one of the major issues for long-run utility systems planning. Chapter 11 in Kavanaugh et al. (1994) examined this element in a sensitivity analysis framework. The role of gas does decline as the assumed escalation rate for gas rises, all else being equal.
The RRIM results do not seem inconsistent with the DOE projections for the nation as a whole. For instance, in the EIA's 1994 Annual Energy Outlook, gas production in the lower-48 states does level off and stay comparatively flat in the 2010 time frame. But gas imports continue an upward trend and electric utility consumption of gas for generation increases considerably over current levels.

References: Energy Information Administration (EIA). 1994. Annual Energy Outlook 1994, With Projections to 2010. DOE/EIS-0383(94), U.S. Department of Energy, Washington, D.C.
Kavanaugh, D.C., D.M. Anderson, P.J. Barton, K.F. Gygi, C.D. McGee, W.H. Monroe, L.J. Sandahl, K.K. Tyler, G.A. Wright, AES Corp. 1994. A Simulation Model for Resource and Rate Impacts in the Western Area Power Administration Services Areas. PNL-8721, Pacific Northwest Laboratory, Richland, WA.

Comment 43 - air emission allowance levels: Appendix A, Section A.1.2. Sulfur dioxide, p. 171, the last paragraph of the section states that allowances granted under Phase II are calculated using the average emission rate of 1.2 pounds (per) mmBtu. This rate is incorrect for many if not most units in the Western area where we must use our allowable emissions rate if it is lower than 1.2. For example, Plain's Escalante Generating Station's multiplier is 0.2. The resulting allowance total is considerably lower than if a 1.2 multiplier were used across the board. Please revisit the target average emission rate and adjust as necessary (Plains Electric Generation and Transmission Cooperative).

Response: The referenced sentence on page 171 of the draft EIS states that "The number of allowances granted to the owner of a unit will be based on the average fuel consumption in million Btus (mmBtu) for the years 1985 through 1987 multiplied by the target average SO2 emission rates of 2.5 pounds per mmBtu (phase 1) or 1.2 pounds per mmBtu (in Phase 2).
There are two instances where the phase 2 target may be modified using a 20-percent adjustment. First, plants that emit SO2 at a rate below 1.2 pounds/mmBtu will be able to increase emissions by 20-percent between the baseline year and year 2000 (Moyer et al. 1993, p. 4-2). Second, plants that produce less than 1.2 pounds/mmBtu during 1985 will be awarded emission credits at the rate of their actual or allowable 1985 emission rate, plus 20 percent, not to exceed 1.2 pounds/mmBtu. Plants emitting less than 0.60 pounds/mmBtu have even more stringent requirements. Thus, after phase 2 begins in the year 2000, the S02 emission rate used to award allowances may be less than 1.2 pounds/mmBtu for plants that are cleaner than the target rate (Section 405(d), 42 USC 7651d) . However, operators may purchase or collect allowances to emit quantities of SO2 greater than the target rate.

This language was added to Appendix A.

References
Moyer, C.A. M.A. Francis, and D.R. Wooley. 1993. Clean Air Act Handbook, A Practical Guide to Compliance: Third Edition. Clark, Boardman, Callaghan, Deerfield, Illinois.
Section 405(d), Title 42 of the United States Code, The Clean Air Act.

Comment 44 - Relationship to other EISs: The draft EIS is flawed in its lack of analysis of the relationship between the Program and other ongoing EIS processes (Land and Water Fund).

Response: There are two power marketing EIS processes under way within Western in addition to the Energy Planning and Management Program. One has resulted in the Salt Lake City Area Integrated Projects Electric Power Marketing: Draft Environmental Impact Statement (DOE 1994). This SLCAO EIS was prepared to address the impacts of a Western proposal to establish commitment levels for sales of long-term firm electrical capacity and energy for the period ending in 2004. This terminus represents the time period when the power marketing provisions of the Program will become active. Thus, even though both analyses address power marketing activities, the Program and SLCAO EISs address different time periods. The Western IRP requirements will become active when the NEPA and Administrative Procedure Act processes are completed. For purposes of analysis we assume that the Program EIS alternative provisions apply to the Salt Lake City area upon adoption.
second NEPA process under way is the Sacramento 2004 Power Marketing Program EIS. This EIS is still in the alternatives analysis stage. As noted in the Draft EIS, the Program IRP provisions will apply to the Sacramento Area, and many Program power marketing provisions will be incorporated into some Sacramento alternatives. Both of these EISes address similar time periods. The Sacramento EIS pays particular attention to power purchases in support of its power marketing activities.
A key point of differentiation between the Program and other EISes is their focus on hydro operations. In the Program EIS, all alternatives are neutral with respect to river and dam operations, even though some may offer Western more flexibility in responding to operational changes stemming from other actions or projects. Both the Sacramento and Salt Lake City EISes analyze potential changes in hydro system operations and potential impacts on river systems.
The IRP provision of the Program will apply to all of Western's long-term firm customers and is not project-specific.

Reference: Salt Lake City Area Integrated Projects Electric Power Marketing: Draft Environmental Impact Statement. DOE/EIS-0150D, U.S. DOE, Washington, D.C.

Comment 45 - allocation amounts: The draft EIS concludes that greater percentage allocations result in less adverse environmental impacts. We do not agree, as this does not take into account Western's substantial purchase activities and associated environmental impacts. Large percentage allocations may have the perverse effect of having coal-fired power purchased by Western displace customer investment in efficiency and renewables (Land and Water Fund).

Response: The analysis for the EIS assumes average water conditions, under which the need for Western purchases are minimal. Further, Western's purchases are constant across the alternatives, and thus, are not explicitly analyzed, although the impacts of these purchases are included equally in each of the alternatives.
One of the key assumptions within the Program Alternatives is that IRP is implemented and all cost-effective DSM measures are acquired up to an investment cap. This cap varies by Area Office and represents the marginal cost of an avoided resource. Assuming that all cost-effective DSM measures are taken, if purchases are needed to augment Western's resources, these purchases are likely to come from thermal power plants. Precisely what type of plants would vary by hydro project, if Western is making the purchase; or by utility system, if customers are making the purchase.
Western does not influence regional load through its power purchases. If Western does not meet a portion of a load, a resource must be acquired to meet the need. This acquired resource has its own set of environmental impacts.

Comment 46 - impact of wind resource on land use: Table 4.1, p. 77, states that wind has 5.9 acres per megawatt capacity. This does not represent the wind variances in the Upper Plains. We have observed that various reports suggest 20 to 80 acres per megawatt (Basin Electric Power Cooperative).

Response: The 5.9 acres per megawatt capacity is based on acres actually occupied by generators, roads, utility lines, and other equipment dedicated to maintenance and operation of the plant. Additional acreage is required for spacing the generators but is available for compatible uses, such as livestock grazing, agriculture, or photovoltaic power production.

Additional acreage may amount to about 113 to 233 acres per megawatt of capacity.
For comparison, we reviewed the Kenetech windpower scoping statement for a project near Carbon, Wyoming, submitted as an attachment to the comment letter on the draft EIS from the Bureau of Land Management. We also sought additional information about the project from Richard Stone at the Bonneville Power Administration. Currently, this project is estimated to require 318 acres of disturbed land to site 70.5 MW of wind generators. This amounts to 4.5 acres/MW. The full development will require 1,847 acres of disturbed land to site 500 MW of wind generators. This amounts to 3.7 acres/MW. The full development will sit on a total of 62,000 acres of land (disturbed and undisturbed). The total amounts to 124 acres/MW. Thus, the range of values is large, but within the range described in the first paragraph above.
Table 4.1 in the EIS has been modified to indicate that the land use environmental impact factor for wind addresses disturbed land only.

Comment 47 - use of modeling results: The draft EIS should state much more clearly, forcefully and frequently that the model results are valid for only the theoretical framework of the EIS, and should not be the basis for comparing future utility performance (Midwest Electric Consumers Association).

Response: Although environmental benefits associated with Program implementation were forecast in the Program draft EIS, Western will not use those predicted energy savings as the measure of successful customer IRP implementation. The predicted energy savings in the draft EIS are useful in identifying regional trends for purposes of environmental analysis, but the assumptions and analysis are far too broad to be useful in setting customer-specific energy savings goals. In fact, the establishment of customer conservation goals by Western would be totally inappropriate, as an IRP should consist of customer-defined goals and objectives.

Comment 48 - number of consumers: The draft EIS should better reflect the number of consumers served through generation and transmission cooperatives that are party to power sales contracts with Western (East River Electric Power Cooperative; Corn Belt Power Cooperative).

Response: Western agrees that a contract for the sale of power to a generation and transmission cooperative provides benefits, through local distribution cooperatives, to thousands of consumers in the region. This situation exists with any large customer serving residential load, and is certainly true for generation and transmission cooperatives that serve a large geographic area. For example, according to the East River Electric Power Cooperative annual report, about 250,000 people are served through East River's 26 member systems over an area the size of the state of Indiana. However, Western does not have consistently reliable information on the number of consumers served by its generation and transmission cooperative customers. Due to this lack of data, no quantification of consumers is included in the final EIS.

Comment 49 - Western resource decisions: Western should not do an IRP itself or make conservation purchases. Existing supply-side powerplants are less expensive than conservation. Conservation is a decision that should be made by power suppliers that are responsible for meeting load growth (Basin Electric Power Cooperative; Central Montana Electric Power Cooperative; Loveland Area Customer Association).

Response: Western believes that integrated resource planning principles should be used in its future acquisition of firming resources. Customers rely on Western to purchase firming energy on a least-cost basis. To meet this responsibility in the future, Western will consider all energy alternatives in its purchase mix, including renewables and energy efficiency. Cost-effective renewable, energy efficiency, and demand-side resources would all compete on an equal basis, with adverse environmental effects of new resource acquisitions being minimized to the extent practicable. Western's customers will benefit by receivingthe lowest possible rates; the environment will benefit from Western's purchases of environmentally sensitive sources of energy; and the larger public interest will be served by Western's efforts to foster the use of clean energy. The acquisition of resources in support of Western's hydroelectric commitments should be based on integrated resource planning principles, with cost-effective renewable resources, demand-side management, and energy efficiency being treated as viable alternatives to the purchase of firming energy. Western will not develop a regional IRP to plan for the resource needs of its customers. The use of IRP principles by Western will be limited to Western's resource acquisition needs for firming of its hydroelectric resources.
Western agrees that its customers are typically responsible for meeting load growth. Western does not want to assume utility responsibility for meeting all regional power needs; this is not an appropriate role for Western. However, Western has committed to the use of IRP principles in its resource acquisition and transmission planning activities. To meet its firm power commitments, Western has historically acquired firming energy from existing generation in the area during periods of below average water conditions. Through

the use of principles of IRP, Western may identify cost-effective renewable resources and demand-side management investments in the future to help meet its resource needs. No acquisition of conservation will take place in the absence of an agreement with the entity whose load is being conserved.

Comment 50 - resource pool: A 10-percent resource pool is arbitrary and unsupported. We support no less than a 25-percent withdrawal from existing customers. Utility status should not be necessary for an allocation of Western power. An alternative should be added reserving a non-competitive allocation of Federal power to tribes in Western's service territory. The draft EIS does not provide a basis for determining whether a 10-percent resource pool is too small. The draft EIS does not define the disposition of new power resources, does not set forth need criteria, does not consider the environmental impact on new customers, does not define equity in the allocation of power and does not define Western's constraints (Oglala Lakota Nation; Standing Rock/Cheyenne River Sioux).

The draft EIS imposes restrictions on the need of our tribe for low-cost hydroelectricity. A resource pool of 25 percent is needed to meet the massive growth in the Southwest and to assure tribes receive an allocation. The draft EIS contains no guidelines or policies for allocations from the resource pool; our need for power to meet irrigation loads is immediate; the draft EIS must address how resource pool power will be allocated to a non-utility preference entity; the draft EIS should consider the needs of applicants for power and the needs of tribes-this would be equitable and serve to uphold the trust relationship of the United States to the tribes (Ute Mountain Utes).

Response: Western has taken several positive steps to assure that the needs of Native Americans for cost-based hydroelectric power are met. In the past, the benefits of hydropower have often been realized by Indians through allocations to cooperatives that serve tribal load. In the future, Western expects to make allocations directly to the tribes. In recognition of the special and unique legal relationship between the United States and tribal governments, the historic requirement of utility status will no longer be maintained for Native American reservations.

Western maintains that the tribes should receive their fair share of the marketable resources available. A power reservation for Native Americans of 25 percent of the current commitments from the Eastern Division of the Pick-Sloan Missouri Basin Program is far greater than that needed to meet a fair share of the power needs of the requesting tribes. Western proposes to allocate power to Native Americans for use on the reservation (and potentially off the reservation under certain circumstances) out of project-specific resource pools, but will determine the size of the pool based upon the need to meet an appropriate share of the load for eligible new customers.

Western does not agree that an alternative should be added reserving a non-competitive allocation of Federal power to tribes in Western's service territory. Neither equity nor environmental quality is served by withdrawing power from existing customers to meet the load growth of new customers. Based on Western's estimate of potential new customer load in the marketing area, a 3-percent resource pool is adequate to meet a fair share of the needs of eligible new customers within the marketing area of the Eastern Division of the Pick-Sloan Missouri Basin Program.

A 25-percent resource pool would equal 500 MW of firm power, a resource far in excess of the loads of all potential new customers in the region. As documented in the EIS, there are increased environmental impacts associated with progressively larger resource pool sizes. Western believes that an extension of less than 90 percent of the resource to existing customers may lead to unnecessary power supply dislocations and potential development of new, but largely unneeded, supply-side resources, lessening the efficiency of the integrated system and defeating the purpose of the Program. Western sees no reason to allocate power to an entity in amounts greater than its loads, as this would deny a valuable renewable resource to existing customers. It is contrary to Western's policy to allow a customer to resell hydropower to third parties.

It is true that the draft EIS does not define the disposition of new power resources, as Western does not know if new Federal resources will be developed. The timing and location of any new resources is unknown. Due to this uncertainty, Western states in the final rule that any new resources will be used to reduce the need to acquire firming resources, retained for operational flexibility, or allocated by the Administrator. Under this approach, Western can make decisions about new resource use at a time when more information is known.

Western agrees that utility status is not required in order for a tribe to enter into a contract for the sale of hydropower. Applicable law does not prohibit this policy decision. As documented in the final rule, Western is willing to enter into a contract with a nonutility tribe as long as the tribe is ready, willing and able to receive the allocation. Western will work with appropriate third parties to assure that the benefits of cost-based Federal hydropower are delivered to Native American consumers.

The draft EIS does not address how the power will be allocated out of the resource pool, or the basis for allocations. These decisions will be made in a project-specific allocation process at a time closer to the expiration date of existing contracts. Such factors as need, equity, Western's constraints and the environmental impact of allocations out of the resource pool will be considered as part of a future, project-specific allocation process. Necessary environmental documentation will be prepared at the time of the project-specific allocation process.

Western supports the Department of Energy's American Indian policy which stresses the need for a government-to-government, trust-based relationship. The key theme throughout

the Department's policy is consultation with tribal governments so that tribal rights and concerns are considered prior to action being taken. Western has met with Indian tribes and tribal representatives throughout the Program public process, and is currently meeting with tribes located in the Missouri River Basin on a monthly basis. To mitigate the economic conditions on reservations within Western's marketing area, Western has responded favorably to the comment that tribal utility status shouldnot be required before a power sales contract can be offered, and has also adopted tribal comment by agreeing to enter into contracts with the tribe directly. These policy decisions clearly show how Western has been responsive to the needs of tribal nations, and that the consultation has been meaningful and substantive.
No decision has been made on the size of the resource pool for potential new customers within the SLCA/IP marketing area. The size of this project-specific pool will be determined at a later date. Western is working with the Ute Mountain Utes to determine if project use power might be made available for certain irrigation pumping loads before existing firm power contracts expire in the year 2004.

Comment 51 - customer resource decisions: Western should not be analyzing customer choices and decisions in the draft EIS. Planning is the job of the utility (Tri-State Generation and Transmission Association).

Response: Western needed to determine the environmental impact of the Energy Planning and Management Program in order to fulfill the requirements of NEPA. This included the direct impacts of Western's actions and the indirect impacts associated with anticipated customer activities in response to the Program. Western predicted the response of its customers in the aggregate for environmental analysis purposes only. The actual choices of resources will be made by the customers, who have the responsibility to meet future needs.

Comment 52 - EIS scope: Western should broaden its purpose and need statement to include objectives such as assuring a stable and reliable hydro resource, assuring rate stability through control of operations and maintenance expense and other program costs, providing flexibility to mutually agree and incorporate changes in Western's programs through customer funding, joint participation and other means to reduce costs (Loveland Area Customers Association; Colorado River Energy Distributors Association).

Response: Western embraces and endorses the objectives suggested. These values are central to Western's strategic plan and are important agency objectives. However, they are beyond the relatively narrow scope of the Program, and will not be added to the purpose and need statement for the EIS.

Comment 53 - contract term: Western should consider additional 25-year rolling extensions at the customer's option when subsequent IRPs are submitted to Western (Loveland Area Customers Association).

Response: Extensions of contracts for an additional 25 years at the customer's option, upon submittal of subsequent IRPs to Western, would cause hydropower resources to be extended too far into the future for Western to respond to changing circumstances over time.

Comment 54 - exchanges with BPA: Western should trade hydropower resources with the Bonneville Power Administration in times of need to avoid purchasing thermal power. (Irrigation and Electrical Districts Association of Arizona).
Western has failed to explore mitigation strategies with BPA (Land and Water Fund).

Response: Western has in the past explored the potential for mutually beneficial exchanges of power between the SLCA/IP and BPA. Suitable transmission arrangements are key to such an arrangement. Western will continue to pursue cost-effective exchange arrangements in the future.

Comment 55 - energy efficiency requirements: The draft EIS alternatives don't include sufficient incentives and requirements to make the Program meaningful. Approval criteria should be developed, such as minimum standards for energy efficiency in each of several customer classes, minimum annual progress requirements to reach those efficiency standards which reflect the capabilities of customer classes, recognition of the relative environmental cost of resource alternatives, and guidelines for selection of new resources which always address environmental costs and encourage selecting alternatives that minimize environmental damage. Western should require customers to meet verifiable

efficiency standards and make resource choices which minimize environmental impact (Sacramento Municipal Utility District).
The draft EIS should document successful examples of load management and conservation; the draft EIS should identify a set of programs/plans to meet efficiency objectives, even if beyond the ability of Western to implement under existing law; Western should comparatively analyze in depth selected C&RE energy activities, with an emphasis on load management and rate design improvements; the use of time-of-day, seasonal and interruptible rates must be considered in the final EIS; Western should consider in the final EIS a rebate program under which Western offers incentives (EPA).

Response: One of these commentors subsequently sent Western a letter appreciating the constructive changes made in the Program, and characterized it as "a well reasoned and forward looking compromise which advances the role of Western and its customers in the transformation of the energy industry to a more sustainable and competitive future. . . . The example set by Western with this Program further demonstrates the value of the federal power marketing program as a force for progress in the utility industry." The initial concerns expressed by this commentor apparently have been satisfied by the issuance of the proposed Program.
Given the diversity of Western's customers and the varying resource strategies employed by our customers, Western has not found an equitable way to judge and appropriately reward the energy efficiency achievements of its customers. For this reason, Western has not adopted incentives, including rebates, as a reward for exceptional energy efficiency achievement. The use of power as an incentive undermines the stability of existing resources that act as the foundation for quality integrated resource planning. Western supports the concept of a pool of assistance dollars that could help supplement and support customers investments in energy efficiency and renewables. Budgetary constraints prevent Western from implementing such a pool in the near future.
Western sees no need to develop efficiency standards for its customers as a basis for measuring successful integrated resource planning. Section 114 of the Energy Policy Act does not mandate such an approach. Customers are responsible for making resource choices to meet their future needs on a least-cost basis; if an efficiency resource is least cost and consistent with the resource strategy of the customer, it will be chosen by the customer. The purpose of an IRP is to identify and foster resource choices that are cost-effective, not to promote a particular type of resource without regard to cost. Western expects that efficiency will be chosen as a resource on its merits as a result of customer IRP development and implementation.
Western will not require the quantification of environmental externalities, with mandatory use of these values in customer resource decisionmaking. The reasons for this decision include the lack of public policy consensus resulting from the ongoing public debate and scientific analysis; the difficulties in developing appropriate quantifications of environmental impacts for the many resources available to customers; and the congressional requirement that Western's customers "minimize adverse environmental effects of new resource acquisitions to the extent practical." This review standard is different from a mandatory environmental externality approach.
In addition, quantification of externalities is a policy question that falls under state jurisdiction at the present time. Establishment of a Western standard would not appropriately reflect comity between the states within Western's service territory and the Federal government. Complicating the issue is the fact, as described in more detail in Chapters 2 and 3, that the western states have widely varying policies on quantification of externalities. Even if Western felt it appropriate to develop a common externality standard, it would be impossible to reconcile such a standard with the heterogeneous approaches of the states. Further, if Western were to require quantification of externalities, Western's customers could find themselves at a inappropriate competitive disadvantage as compared to non-customer utilities not bound by such a stringent standard under state laws and regulations. For all of these reasons, Western will not require the quantification of externalities in the final Program.
Incentive rates and rate design modifications will not be analyzed as part of the Program EIS, as they are outside the scope of the Program. Rate issues, including incentive rates and rate design, should be addressed within Western's long-established public ratemaking process. Western anticipates that the use of incentive rates and rate design by Western's utility customers could be a reasonable option to pursue as part of their IRPs. Western will provide technical assistance on this subject to customers on request.
The draft EIS documents certain examples of load management and conservation that are successful. Western's technical assistance program, as embodied in the Resource Planning Guide, documents virtually every efficiency, conservation and load management activity that exists in the utility industry today. Further, many comments on the draft EIS document the extensive customer activities in these areas.
Alternatives beyond the ability of Western to implement under existing law were not considered, as the purpose and need statement requires that the Program be developed in an equitable manner consistent with Western's legal obligations and constraints.

Comment 56 - program scope: Western should broaden the scope of its proposals to include various reforms, including better decisional processes for power purchases/transmission investment; development of a strategic plan to assist customers in acquiring renewables/efficiency; incentives to encourage energy efficiency/renewables; establishment of clear-cut criteria for purchase power; meaningful IRP requirements. It is premature to essentially lock in current allocations given the substantial uncertainties surrounding ongoing environmental processes. Western's heavy reliance on purchased power creates both economic and environmental risks; these purchases could become substantially more expensive given increased regulation of SO_2 and CO_2 in the future. These risks should be borne by the selling utilities; more rapid acquisition of renewables/efficiency would mitigate the need for purchase power; be more proactive in using your grid to deliver renewables to the market, expand your technical assistance on renewables, and develop a renewable resource acquisition target (Land and Water Fund).

Response: Western agrees that integrated resource planning principles should be used in its future acquisition of firming resources and in future transmission planning. Customers rely on Western to purchase firming energy on a least-cost basis. To meet this responsibility in the future, Western will consider all energy alternatives in its purchase mix, including renewables and energy efficiency. Cost-effective renewable, energy efficiency, and demand-side resources would all compete on an equal basis, with adverse environmental effects of new resource acquisitions being minimized to the extent practicable. Western's customers will benefit by receiving the lowest possible rates; the environment will benefit from Western's purchases of environmentally sensitive sources of energy; and the larger public interest will be served by Western's efforts to foster the use of clean energy. Western has taken positive action to implement integrated resource planning principles by starting a separate public process to receive input on implementation of Western's commitment. 59 FR 62724 (December 6, 1994).

The acquisition of resources in support of Western's hydroelectric commitments should be based on integrated resource planning principles, with cost-effective renewable resources, demand-side management, and energy efficiency being treated as viable alternatives to the purchase of firming energy. Risk management (such as assessing the risk of future regulation of SO_2 and CO_2) will be part of Western's principles. These principles are being developed in a separate public process. Western will not develop a renewable resource acquisition target as part of this Program, but will consider such an approach under the separate public process that is ongoing. Renewables will be assessed on their merits, and acquired pursuant to Western's use of principles of IRP.

Western has a strong desire to support the development of renewables. An overview of Western's actions in support of renewables helps put the comments received on the Program in proper context. Recently, Western has committed to undertake a market assessment of the potential for solar power in the southwestern United States as part of the Solar Enterprise Zone initiative. Western has offered its marketing, transmission and power system operations expertise to the SEZ.

Western has been active in promoting renewable energy in partnership with Native American Indians. Western, in coordination with the Navajo Nation, the Department of Energy and Sandia National Laboratory, has been instrumental in supplying forty photovoltaic units to the Navajo Tribal Utility Authority for installation at remote homes on the Navajo reservation. As extensions of distribution lines to these remote locations would be prohibitively expensive, installation of photovoltaic technology is a commercially viable alternative. Western has contributed to an assessment of wood fuel supply on the White Mountain Apache reservation to determine the quantity of this fuel available for power cogeneration. To promote Indian health, Western is participating in the Navajo Rootfuel Promotion project, which will evaluate the feasibility of growing and harvesting rootfuels as a replacement for coal as a fuel in Indian homes. Another example of a partnership between Western and Native Americans is an assessment of the feasibility of producing biogas fuel from solid wastes to meet the needs of remote Navajo villages and cluster homes.

In addition to the many renewable resource workshops that have been sponsored and the numerous publications that Western has developed, Western has created the Resource Planning Guide, a technical assistance tool that will help customers to prepare integrated resource plans as required by section 114 of the Energy Policy Act of 1992. The RPG is a personal-computer based piece of software that will allow customers to evaluate renewable resources as a future resource.

Western's Sacramento Area Office recently provided technical assistance for a feasibility analysis of using wind-generated energy at Lawrence Livermore National Laboratory. If the analysis is favorable, Western will work with the laboratory to implement the use of wind energy. Western has also made its transmission system available to wheel power from wind generation to load. All of these activities show Western's commitment to the fostering of renewables as an important factor in the nation's future resource mix.

Given the diversity of Western's customers and the varying resource strategies employed by our customers, Western has not found an equitable way to judge and appropriately reward the energy efficiency achievements of its customers. Forthis reason, Western has not adopted incentives, including rebates, as a reward for exceptional energy efficiency achievement. The use of power as an incentive undermines the stability of existing resources that act as the foundation for quality integrated resource planning. Western supports the concept of a pool of assistance dollars that could help supplement and support customers investments in energy efficiency and renewables. Budgetary constraints prevent Western from implementing such a pool in the near future.

Western is not locking in current allocations. Western is extending a percentage of the resource available at the end of the term of existing contracts, to allow the impacts of ongoing assessments of operational changes to be reflected in Western's marketable commitments. After the extension contracts become effective, Western has the right to adjust its commitments on five years' notice in response to changes in operations or long-term hydrology. These Program features are designed to accommodate changing circumstances, not to impede Western's flexibility.