Summary

The Western Area Power Administration (Western) is an agency of the U.S. Department of Energy charged with marketing and transmitting Federally produced electricity throughout a 1.3 million-square-mile geographic area. The majority of this electricity comes from federally owned and operated hydroelectric plants. Western's service region represents the largest geographic area served by a Federal power marketing agency. It covers 15 States from Minnesota in the northeast to California in the southwest. The organization is headquartered in Golden, Colorado. Western's five area offices are in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; Sacramento, California; and Salt Lake City, Utah.

Western proposes to establish an Energy Planning and Management Program (the Program) to replace its Guidelines and Acceptance Criteria (G&AC) for the Conservation and Renewable Energy (C&RE) Program and to evaluate ways to make 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 enhance 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 Western could continue to market power on a project-specific basis in the future.

Legislation specifically authorizing Western's C&RE Program was included in Title II of the Hoover Power Plant Act of 1984 (42 U.S. Code [USC] 7275-7276). After this legislation was passed, an amendment to the G&AC was issued on August 21, 1985 (50 Federal Register [FR] 33892). The amended Program is described in Chapter 2, Alternatives.

A review of Western's amended 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]). 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.

On October 24, 1992, the Energy Policy Act of 1992 (the Act) (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. The new legislation requires Western's customers to prepare and implement IRPs. Changes to Western's proposed 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. Much of this legislation is consistent with Western's ongoing administrative development of the Energy Planning and Management Program. This EIS recognizes and incorporates the Act into the Program.

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 will fulfill that mandate.

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.

Currently, Western markets its resources through independent marketing plans that are specific to the Federal power projects in Western's service region. Under the proposed Program, rates would continue to vary from project to project reflecting project costs, but the Program Alternatives contain some contract provisions that would be consistent across Western. Contractual provisions outside of the Program would continue to vary on a project-specific basis.

The two parts of the proposed Program are the Power Marketing Initiative (PMI) and the Integrated 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 customer's 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.

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. Tables S.1 and S.2 summarize the various PMI and IRP components and describe how they fit into the alternatives.

Potential Program components have been combined to form 13 alternatives, including a No-Action Alternative. Since publishing the draft EIS, Western has chosen a Preferred Alternative. 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. The Preferred Alternative is made up of the same type of components described in section 2.1. Table S.3 summarizes the 13 alternatives.

A number of issues were raised during the scoping process that were determined to be outside the scope of this EIS. Examples of these issues include transmission access, incentive rates and rate design modifications by Western, and river and dam operations. A discussion of these issues can be found in Section 2.2.

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 response is is found in Appendix G.

S.1 PHYSICAL ENVIRONMENTAL IMPACTS

The environmental analysis of the alternatives fully analyzes those impacts that are predictable without knowing the specific locations that would be affected. For example, the quantity of air pollutants that may be emitted under each of the alternatives is estimated. As specific actions are established, detailed environmental analyses would be developed by those initiating the projects as required by State and Federal legislation. It is unlikely that Western would initiate such projects.

Figure S.1. Surcharge Penalty Provisions of the Energy Policy Act of

1992(a)

TABLE S.1 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 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 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 environ- mental effects (Energy Policy Act of 1992).

TABLE S.2 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 Prefer red 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 S.1. The Act also allows for a 10% power reduction as an optional penalty.

%TABLE S.3 Summary of Energy Planning and Management Program Alternatives Including the Preferred Alternative

The environmental analysis in this EIS involves the straightforward approach of multiplying an environmental impact factor by the generation or capacity associated with energy resources deployed under each of the alternatives. The result is an estimate of certain environmental impacts such as air emissions or solid waste production. The capacity and generation projections were modeled for each of Western's area offices.

The electricity generation modeling in Western's service region showed relatively slight differences among the Program Alternatives as compared to the No-Action Alternative, which resulted in more generation. Along with capacity additions of power plants, which were also found to be greater under the No-Action Alternative, these differences in generation result in the potential environmental impacts summarized in this section. Conservation activities resulting from energy planning dominated those changes caused by the PMI provisions. This difference in electricity demand results in the prominent difference between the No-Action Alternative and the Program Alternatives. Uncertainty arising from varying contract lengths and percentage extensions causes some variation among the Program Alternatives.

In all of the areas, the predicted customer response to the Program reduced energy usage by roughly 2 percent to 6 percent in the year 2015. Western's customers are forecast to use 5 percent to 15 percent less energy in the year 2015; this represents about 13.4 billion kilowatt hours in reduced usage by Western's customers in the year 2015, the equivalent of about 45 percent of the firm energy that Western markets today. 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 building stock, are predicted to have larger potential savings.

Table S.4 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. The resources included in the model for potential growth in generation capacity over the next 20 years are coal-fired power plants, gas-fired simple-cycle combustion turbines, gas-fired combined-cycle combustion turbines, hydroelectric plants, and other renewables using wind and geothermal technologies. Resources that were not modeled are included in the table to allow for comparison.

As specific resources are chosen, additional environmental analyses will be necessary. Western will complete these analyses for the resources that the agency initiates, if any. Most, if not all, of the resources will be proposed and built by individual utilities or utility-based associations. For these non-Federal projects, environmental analysis and documentation will come in the form of siting, discharge, and use permits issued by local, state, and Federal agencies. Federal permits may require NEPA documentation, which will be determined by the issuing agency.

Table S.3 summarizes the salient provisions of the 13 alternatives included in this EIS. All Program Alternatives would have less adverse environmental impacts and neutral economic impacts compared to the No-Action Alternative. The impacts of the Program Alternatives show relatively slight differences among them. Only the No-Action Alternative has substantially different impacts. Tables S.5 and S.6 show total potential impacts and indicate how much the impacts of each alternative differ from those of the No-Action Alternative. The Preferred Alternative, which was not directly modelled in this EIS, falls within the range of activities and impacts of Alternatives 5 and 6.

The findings from the analysis presented in this EIS suggest that, in comparison with the No-Action Alternative, any of the Program Alternatives would result in fewer environmental impacts over time. When compared to emissions of the entire utility industry in Western's service region, these reductions appear small. However, in absolute terms, the reductions are important. For example, a typical 500-MW coal plant produces 2,600 tons of sulfur oxides (SOx), 5,200 tons of oxides of nitrogen (NOx), 500 tons of total suspended particulates (TSP), and about 3.2 million tons of carbon dioxide (CO2) annually. The Program Alternatives would reduce annual emissions by about the equivalent of one to two coal plants in 2015. A similar comparison with natural gas-fired simple cycle combustion turbines at a 65 percent capacity factor results in offsetting about 11 to 14 250-MW units when SOx is ignored. Natural gas combustion turbines produce little SOx in comparison with coal plants.

A summary of estimated impacts for the year 2005 is shown in Table S.5. Estimates for the year 2015 are shown in Table S.6. The table shows relatively little distinction among the Program Alternatives. The variation that does occur is associated with the percentage extension of Western firm power included in each alternative, and the uncertainty confronted by Western's customers in response to varying contract extension periods.

Several general trends are apparent from the analysis. First, all Program Alternatives would tend to result in fewer adverse impacts in comparison to the No-Action Alternative. This trend is true for all of the physical environmental impacts analyzed and most of the economic impacts, and can be attributed to increased customer investment in demand-side resources instead of power plant construction. One exception is short-term rate impacts, which rise slightly to pay for planning activities (see Section 4.10.2). However, in the long-term, rates would tend 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 show neutral to positive effects resulting from the Program Alternatives (see Section 4.9).

Another trend is 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 is predicted in 2015 when assured, relatively high percentages of Western resources are extended. The Non-Extension Alternatives are consistently less beneficial to the environment than the other Program Alternatives across all impact categories. This trend is attributed to relatively higher levels of plant construction and electricity generation by existing customers in reaction to uncertainty in Western's commitments. The Limited Extension Alternatives and the Extension Alternatives, which feature an assured, high-percentage extension of existing resources, result in similar effects. The size of the resource pool contributed to uncertainty levels by reducing Western resources available for commitment. However, the manner in which the resource pool is used did not influence the analysis.

The third trend is true of all of the alternatives and is seen in the quantities of impacts over time. Impacts that are tied to coal combustion, such as SOx emissions and ash production, tend to peak in the year 2005, then decline or remain constant. This trend mirrors the quantity of electricity generated from coal plants. Between 1995 and 2005 generation from coal plants tends to increase as these plants are used to meet increasing loads in areas with surpluses of generation capacity at present. After 2005, the use of coal plants tends to decline as the plants age and are replaced with less capital intensive new technologies, such as combined-cycle combustion turbines (see Section 4.3.1). With all alternatives, impacts that tend to result from all thermal power plants, such as thermal discharge and CO2 emissions, show a steady increase over time, although the Program Alternatives are estimated to result in fewer impacts than the No-Action Alternative.

Electricity generation from coal plants is also related to a fourth trend. Coal combustion, and its related effects, tend to remain relatively unchanged across the Program Alternatives. Effects that result from both natural gas and coal (for example, thermal discharge, water consumption, and CO2 emissions) tend to vary more by alternative 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 differences between Program Alternatives, the change varies from 2 percent to 23 percent.

%TABLE S.4 Planning and Environmental Profiles for Energy Resources

%TABLE S.4 Planning and Environmental Profiles for Energy Resources, continued

%TABLE S.4 Planning and Environmental Profiles for Energy Resources, continued

%TABLE S.5 Summary of Physical Environmental and Direct Employement Impacts Associated with each Alternative in 2005

%TABLE S.6 Summary of Physical Environmental and Direct Employment Impacts Associated with each Alternative in 2015

A final trend is found in the distinction between physical impacts resulting from generation and those resulting 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 tend 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, tend to dominate the effects of new plants, have a much greater influence on the effects resulting from electricity generation.

S.2 ORGANIZATIONAL IMPACTS

Early in the EIS scoping process for Western's proposed Program, feedback from various organizations made it clear that potential programmatic impacts could alter the ways in which the organizations operated. Many of these effects are not readily quantified, yet they could have significant consequences for Western 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 this EIS.

When comments on these impacts were reviewed, they fell into 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.

The potential organizational impacts of Western's alternatives were analyzed using data collected from meetings with 42 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, etc.) and geographic regions.

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.

For all customers, the IRP provision component would have the largest effect on the administrative burden impact. The extension period, IRP provision, and percentage extension options tend to be the most influential for the other impact types. For some customers, the penalty provisions would have a large effect on impacts. A rate penalty option was initially considered for all alternatives with the exception of the No-Action Alternative; however, this has changed under the Energy Policy Act of 1992, which defined the new penalty provision requirement. The resource extension percentage component had the largest influence on participants' overall preferences.

The results of the trade-off analysis were used to estimate the relative impacts of each of the Program Alternatives. The impacts were measured with respect to the best and worst possible combinations of Program components. Table S.7 summarizes the organizational impacts of the Program Alternatives averaged across all Western customers. The Preferred Alternative is treated as a combination of Alternatives 5 and 6 and is not addressed separately. All of Western's customers perceive the No-Action Alternative to be more favorable than the other alternatives.

Several of the Program Alternatives proposed by Western strike a balance between components, e.g., shorter extension periods are combined with larger percentage extensions. This has the effect of narrowing the range of impacts on Western's customers, even though customers may differ in their perceptions about how the Program components would impact them. With the exception of the No-Action Alternative and Alternative 9, one of the Limited Extension alternatives, Western's customers did not uniformly view alternatives as having extreme, polar impacts. Alternative 9 ranked the worst in the flexibility impact category due to the unfavorable effects of an IRP requirement for all customers and a short extension period for some projects followed by a low percentage extension.

In many cases, the resource extension percentage component had an influential role in determining the outcome of the alternatives. The No-Action has "best" ratings primarily from the favorable impacts of the 100 percent resource extension. Likewise, the PMI Non-Extension Alternatives (11 and 12) have better impacts compared with the rest of the alternatives because of an assumed 100-percent extension. Assuming a 25-year extension period and a 90 percent resource extension to take effect after the 10-year bridging period, the PMI Limited-Extension Alternatives tend to be perceived unfavorably because of the 90 percent resource extension. The Preferred Alternative, which is a combination of Alternatives 5 and 6, has less impact on the environment than most alternatives.

S.3 RATE IMPACTS

Impacts were analyzed from three perspectives. A utilities system model was used to estimate long-term impacts resulting from utility acquisition of energy resources. Impacts that would result in the near term directly from the costs of planning activities and from a 10-percent reduction in Western's resource allocation were analyzed separately.

S.3.1 Long-Term Utility Planning

The long-run impacts of the Program on rates are not uniform across the utilities in Western's region. While the results reflect a variety of elements, the major impacts of the Program Alternatives are due to additional investment in DSM resources and from the displaced need for thermal plant additions to meet expected future loads. Areas where non-generating retail utilities rely more on DSM than before reflect slight increases in average retail rates. In contrast, generating public utilities that provide auxiliary supply to retail utilities and serve their own mix of end-use load reflect uniformly lower rates by 2015. This stems from less need to build more expensive thermal resources and the balance of these avoided costs with total system requirements.

%TABLE S.7 Organizational Impacts of Draft EIS Alternatives

%TABLE S.8 Difference in Retail Rates between No-Action and Program Alternatives (in nominal dollars)

The average rates of Western's generating public utility customers are approximately 5 to 8 percent lower under the Program cases than under the Program's No-Action Alternative. For non-generating utility classes, the rate impacts run from 12 percent lower to 5 percent higher than the No-Action case. These impacts are tempered by the fact that they occur 25 years into the future; nearer-term impacts on rates from the Program appear virtually nil.

S.3.2 Short-Term Utility Planning

The potential average short-term rate impact resulting from IRP preparation for end-users of electricity was estimated. It was assumed that all costs increased in one year and that they were passed on to end-use customers. Costs ranged from 0.21 mills/kWh to 2.1 mills/kWh. A small number of examples based on actual experiences resulted in costs either below or at the low end of this range. This estimate was assumed to be a conservative (high-end) range that applies to each of the alternatives except the No-Action Alternative, which would have no incremental costs.

S.3.3 Reduction in Firm Power Allocation

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 regions within the marketing area of Western's five area offices. The average wholesale rate for non-Federal power represents 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 may be thought of as the additional expense incurred by Western's customers as a result of the reduction in available firm power. Table S.9 summarizes the results.

Those customers purchasing the greatest quantities of power from Western would experience proportionally greater rate impacts. If the power were redistributed to new customers, these utilities' rates would likely decrease.

TABLE S.9 Dollar Expense to Western Customers of a 10% Reduction in Available Western Firm Power

Area	Cost to Customers of 10% Reduction in Firm Power	Average Wholesale Rate for Non-Federal Power (mills/kWh)	Western Composite Rate (1991) (mill/kWh)
Billings	$189,59,565	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	32.6
Salt Lake City	$11,210,610	36.13	16.20