SECTION 2
BACKGROUND

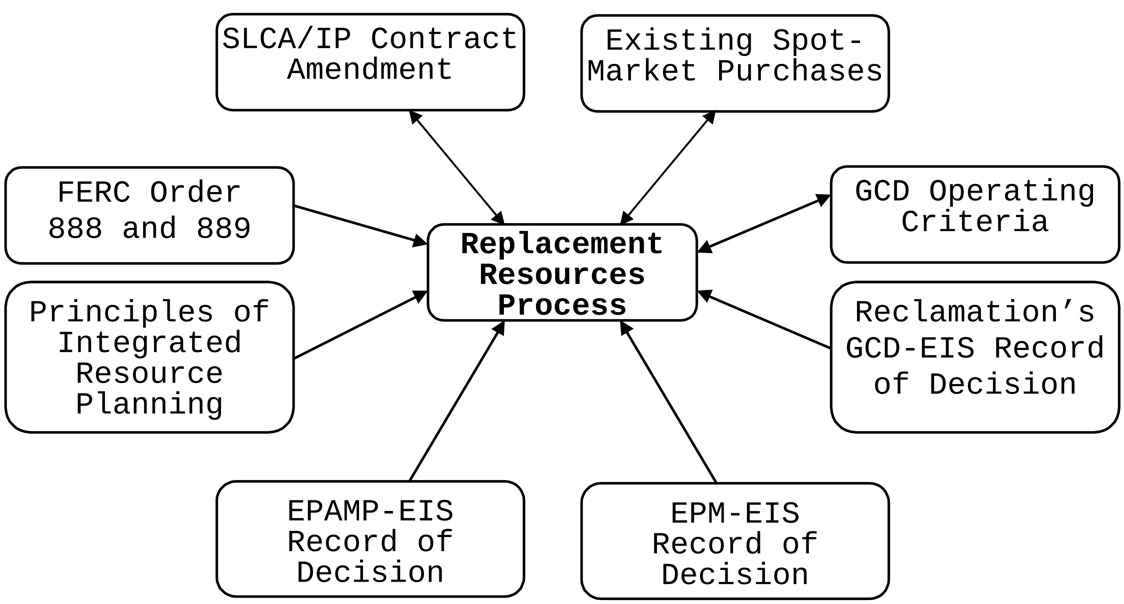
2.1 INTRODUCTION

In addition to the changed operations at GCD and the resulting loss of generating capability at the Glen Canyon power plant, many other related Western processes and policies will influence the Replacement Resources Process. This section describes the context of the Replacement Resources Process, including an overview of the SLCA/IP and GCD operations, historical events and precedents, a discussion of potential future operational changes, and other relevant policies and processes that influence the Replacement Resources Process.

Figure 2-1 illustrates some of these key process and policy influences on the Replacement Resources Process, which are addressed in further detail.

FIGURE 2-1

INFLUENCES ON WESTERN'S REPLACEMENT RESOURCES PROCESS BY OTHER RELATED POLICIES, PROGRAMS AND PROCESSES



2.2 WESTERN AND THE SLCA INTEGRATED PROJECTS

Western is a power marketing administration within the Department of Energy (DOE) created by the Department of Energy Organization Act in 1977. This act transferred the power marketing and transmission functions from the Secretary of the Interior (Bureau of Reclamation) to the Secretary of Energy, acting through Western. Western's mission is to sell and deliver electricity from the power plants built as a part of certain Federal water projects which is generated in excess of project use (power required for the project operation. Western's power marketing responsibilities begins at the switchyard of Federal hydroelectric power facilities, and includes the operation and maintenance of transmission facilities interconnected with regional utilities.

Western's CRSP Customer Service Center (formerly the Salt Lake City Area Office) is responsible for marketing power from the CRSP, the Collbran Project, the Rio Grande Project, and the Provo River Project. The Glen Canyon power plant is the CRSP's largest power plant, with the other resources being Flaming Gorge, Fontenelle, and the Aspinall Unit (comprising Blue Mesa, Crystal, and Morrow Point power plants). On October 1, 1987, the CRSP, the Collbran Project and Rio Grande Project were integrated for marketing and rate-making purposes, and are collectively known as the SLCA/IP.

The SLCA/IP includes hydroelectric generating features located on the Colorado, Green, Gunnison, and Rio Grande rivers, in the states of Arizona, Colorado, New Mexico, Utah, and Wyoming. The SLCA/IP facilities together have an installed capacity of 1,763 megawatts (MW). In fiscal year 1996, the SLCA/Integrated Projects had a net maximum operating capacity of 1,774 MW and generated 7,459,000 megawatt-hours (MWh) of net energy.

2.2.1 SLCA INTEGRATED PROJECTS FIRM-POWER CUSTOMERS

In addition to Reclamation project use loads, Western currently serves 138 wholesale firm-power customers from the SLCA/IP, including municipal utilities, rural electric cooperatives, federal and state agencies, and irrigation districts. Western's current long-term electric service contracts with these SLCA/IP firm-power customers extend through fiscal year 2004.

Current power rates for SLCA/IP firm-power (referred to as Rate Schedule SLIP-F5) are 0.89 cents per kWh and $3.83 per kW-month, or a composite wholesale rate of approximately two cents per kWh (or $20.17 per MWh).

SLCA/IP firm-power customers are located in the states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming. Customer dependence on SLCA Integrated Projects power varies widely, but about half of the firm-power customers receive less than twenty-five percent of their total energy requirements from the SLCA/IP.

2.2.2 GLEN CANYON DAM AND POWER PLANT

Glen Canyon Dam was authorized in April 1956 by the CRSP Act. Construction of the dam and all eight associated generating units was completed in 1966. Glen Canyon Dam and power plant (GCD) is located on the Colorado River in northern Arizona, near the Utah border. GCD operations are controlled by Reclamation to meet water storage and delivery requirements to the Lower Colorado River Basin consistent with the laws, treaties, contracts, and court decisions on Colorado River operations, known collectively as the Law of the River.

The eight generating units at GCD have a combined nameplate capacity rating of 1,288 MW, and produced 5,506,000 MWh of energy in fiscal year 1996. The generation available from GCD is highly variable; its average annual generation during the last fifteen years was 5,166,000 MWh, with a low of 3,599,000 MWh (1992) and a high of 8,818,000 MWh (1985). As the largest of the SLCA/IP generating resources, GCD currently represents about two-thirds of the total SLCA/IP marketable capacity and seventy-five percent of the marketable energy.

Historically, GCD has been used primarily to generate peaking power. While operating this way made the power generated at Glen Canyon more valuable, it also caused significant hourly and daily fluctuations in water releases. These fluctuations caused concern because of their potential effects on downstream recreational, cultural, ecological and biological resources.

The maximum possible release at GCD was designed to be 33,200 cubic feet per second (cfs). With the completed generator uprate and rewind program in 1982, growing concerns developed over the potential impacts from greater magnitude and frequency of releases from GCD. Also at issue was the adequacy of existing environmental documentation prepared by Reclamation. As a result, Reclamation established an institutional maximum release constraint of 31,500 cfs until the growing public concern could be addressed. In December 1982, Reclamation began Phase I of the multi-agency Glen Canyon Environmental Studies (GCES) to respond to the concerns of environmental and recreational interests regarding GCD operations. Phase I of the GCES was completed in 1988. In June 1988, Phase II of the GCES was initiated to address economic impacts to power customers, along with other concerns. Phase II also incorporated additional data collection from special research flows conducted from June 1990 through July 1991.

2.2.3 OTHER SLCA INTEGRATED PROJECTS RESOURCES

Operations at several other SLCA/IP facilities are also likely to be modified to remedy perceived environmental concerns. These facilities include the Flaming Gorge, Aspinall Unit, and Collbran Project power plants, and possibly the Rio Grande Project Elephant Butte power plant.[1] Such operational changes could reduce the total capacity available to SLCA /IP customers.

2.2.3.1 Flaming Gorge

Flaming Gorge Dam and power plant is located on the Green River in northern Utah, 40 miles north of Vernal. The three generating units have a combined maximum capability of 151 MW and a useable operating capacity of 141 MW. About 667,000 MWh of energy were generated in fiscal year 1996. Like Glen Canyon, annual generation available from

Flaming Gorge power plant is highly variable from year to year. The average annual generation during the last fifteen years was 498,000 MWh, with a low of 252,000 MWh (1989) and a high of 885,000 MWh (1984).

The Final Biological Opinion for the Operation of Flaming Gorge Dam issued by the U.S. Fish and Wildlife Service (USFWS) on November 25, 1992 discusses the effects of Flaming Gorge power operations on endangered fish species. The reasonable and prudent alternative included in this biological opinion recommends changes to mimic the natural pre-dam flows in the Green River and to preserve declining populations of Colorado Squawfish and other endangered fish species.. Dam operations have been altered since 1985 to improve habitat conditions for these fish species, and the dam is currently operated to comply with the reasonable and prudent alternative.

Research and recovery test releases as part of the Biological Opinion currently limit the amount of useable peaking capacity at Flaming Gorge. Maximum water release is currently limited to approximately 4,500 cfs, while minimum release is normally 800 cfs. The operating constraints resulting from the Final Biological Opinion combine to reduce the useable Flaming Gorge on-peak capacity by about 50 megawatts. Exception criteria for emergency situations and system regulation, similar to those in effect for Glen Canyon, have been included in the 1992 Biological Opinion and are currently in effect at Flaming Gorge.

2.2.3.2 ASPINALL UNIT

The Aspinall Unit, comprised of Blue Mesa, Morrow Point, and Crystal Dams and power plants, is located on the Gunnison River in west-central Colorado. The combined operating capacity of the Aspinall Unit is 277 MW, which produced 1,050,000 MWh of energy in fiscal year 1996. Annual generation from this unit also varies considerably. Generation has averaged 861,000 MWh during the last fifteen years, with a low of 452,000 MWh (1990) and a high of 1,253,000 MWh (1984). Normal maximum water releases are currently 1,600 cfs at Crystal, 5,300 cfs at Morrow Point, and 3,700 cfs at Blue Mesa. Only Crystal currently has minimum release requirements of 300 cfs below the Gunnison Tunnel, and 300 cfs below the Redlands diversion, subject to certain Blue Mesa reservoir storage requirements. However, physical limitations and restrictions on the operation of Crystal dam severely limit Western’s hourly power scheduling decisions, unlike operations at Morrow Point and Blue Mesa.

Like Flaming Gorge, the Aspinall Unit has been undergoing research and recovery test releases as part of Section 7 consultation under the Endangered Species Act. This five-year program of research flows and test releases will be in place until 1997. Following completion of this research, the USFWS is expected to issue a biological opinion on operations of the Aspinall Unit.

2.2.3.3 OTHER FACILITIES

Although the other SLCA/IP facilities at Fontenelle, Collbran and Rio Grande are not affected by hourly power scheduling decisions made by Western, operations at these facilities are also likely to be affected by environmental concerns in the future. While operational changes at these other facilities would not affect Western’s power scheduling flexibility, the total capacity available to SLCA/IP customers could be reduced.

2.2.4 SLCA INTEGRATED PROJECTS FIRM LOAD

In addition to serving Reclamation project use loads, Western markets SLCA/IP firm power at “Post-1989” levels. This marketing level was put into effect in October 1996 upon the signing of the Record of Decision (ROD) on Western’s Electric Power Marketing EIS. For the purposes of this report, the interim allocation contract rate of delivery (CROD) in effect up until October 1996 has been assumed for the SLCA/IP, as shown in Table 2.1.

TABLE 2-1

TOTAL SLCA/IP INTERIM POST-1989 ALLOCATION CROD

STATE	WINTER SEASON		SUMMER SEASON	
	CAPACITY (MW)	ENERGY (MWh)	CAPACITY (MW)	ENERGY (MWh)
Arizona	111	239,915	209	506,938
Colorado	484	1,053,048	469	1,148,920
Nevada	43	86,776	45	105,335
New Mexico	244	475,532	220	506,803
Utah	392	781,545	311	724,367
Wyoming	17	34,939	15	35,177
Total	**1291**	**2,671,755**	**1269**	**3,027,540**

2.2.5 GCD OPERATIONS

2.2.5.1 OPERATING CRITERIA To protect downstream resources, Reclamation implemented operating procedures in February 1997, to operate GCD in a restricted mode. The operating procedures include release criteria which limit the maximum release rate to 25,000 cfs, reducing the useable capacity at GCD to about 1,000 megawatts at current reservoir levels.[2] Minimum releases of 5,000 and 8,000 cfs (depending on the time of day) must be maintained, and ramp rate restrictions are in effect as well. Down ramp rates are limited to 1,500 cfs per hour and up ramp rates are limited to 4,000 cfs per hour to avoid the rapid rise and fall of water levels downstream from GCD. Finally, the maximum daily (24-hour) change in water release is limited to 5,000 cfs/day to 8,000 cfs/day, depending on the monthly release volumeLimiting the maximum allowable release results in a lower available on-peak capacity, while restricting ramp rates and the allowable daily change in flow, reduces operating flexibility, or the ability to follow hourly and instantaneous changes in electrical load. Increasing minimum flows also reduces the total value of energy generated by forcing increased off-peak releases and limiting the ability to make high-cost, on-peak economy energy sales from low-cost, off-peak purchases. The overall effect of the interim operating criteria is to reduce the amount of operable hydroelectric capacity and energy generation during on-peak hours, and increase the amount of energy generated off-peak.

The operating criteria also outline operating procedures to address certain emergency and system regulation requirements. These procedures allow water releases to exceed the flow restrictions imposed by the operating criteria.

The degree to which Western can use hydroelectric generation to respond to emergencies and system regulation requirements is an important consideration in the Replacement Resources Process, because it influences the characteristics of replacement power. Because capacity from GCD can be used to serve load under emergency circumstances, Glen Canyon has a higher useable on-peak capacity, albeit for short periods of time. Replacement power can therefore be obtained at lower cost on the bulk power market than would be the case in the absence of these emergency and system regulation procedures.

2.2.6 GLEN CANYON DAM EIS

In July 1989, the Secretary of the Interior announced that the Bureau of Reclamation would prepare an EIS on the effects of GCD operation on the downstream environment under guidelines established by the National Environment Policy Act of 1969. The study area in the GCD-EIS was the Colorado River corridor from GCD through the Grand Canyon down to Lake Mead. The following alternative flow regimes were identified:

- <u>No Action</u>: Maintain fluctuating releases and provide baseline for impact comparison
- <u>Maximum Power Plant Capacity</u>: Permit full use of power plant capacity
- <u>High Fluctuating Flows</u>: Slightly reduce daily fluctuations from historical no-action levels

- Moderate Fluctuating Flows: Moderately reduce daily fluctuations from historical no-action levels
- Modified Low Fluctuating Flows *(Preferred Alternative)*: Substantially reduce daily fluctuations from historic no action levels
- Interim Low Fluctuating Flows: Substantially reduce daily fluctuations from historic no action levels; same as interim operations
- Existing Monthly Volume Steady Flows: Provide steady flows that use historic monthly release strategies
- Seasonally Adjusted Steady Flows: Provide steady flows on seasonal or monthly basis
- Year-Round Steady Flows: Provide steady flows throughout the year

From the No Action alternative to the restricted fluctuating and steady flow alternatives, the operating flexibility at GCD is increasingly limited. The maximum allowable release rates decrease, and the minimum allowable release rates increase, resulting in a narrower range of dam and power plant operations. Operations are further restricted by limiting the allowable daily change (daily fluctuation) in release rates.

The draft GCD-EIS was released by Reclamation in January 1994, and identified the Modified Low Fluctuating Flow (MLFF) alternative as the preferred alternative. The draft preferred alternative allowed for a maximum release rate of 20,000 cfs, a minimum release rates of 5,000 cfs at night and 8,000 cfs during the day, a daily fluctuation limits of 5,000, 6,000 or 8,000 cfs per day depending on monthly volume, an up ramp rate of 2,500 cfs per hour, and a down ramp rate of 1,500 cfs per hour. The draft preferred alternative also included habitat maintenance flows, beach- and habitat-building flows[4], flood frequency reduction measures and endangered fish research flows.

After releasing the draft GCD-EIS, additional scientific information from ongoing research and public comments prompted Reclamation to modify the preferred alternative in the final GCD-EIS.[5] The modifications to the final preferred alternative included: increasing the maximum release rate from 20,000 cfs to 25,000 cfs; increasing up ramp rate from 2,500 cfs per hour to 4,000 cfs per hour; and deferring endangered fish research flows. According to the GCD-EIS, winter on-peak capacity at GCD with endangered fish research flows would be reduced from 1,288 MW to 945 MW, summer capacity would be reduced from 1,288 MW to 852 MW, and average annual energy would remain unchanged at 6,010,000 MWh, but redistributed throughout the months of the year.

The endangered fish research flows remain as an element of the reasonable and prudent alternative identified in the final Biological Opinion issued by the USFWS in December 1994,[6] as a result of Section 7 consultations with Reclamation on the preferred alternative (MLFF). The reasonable and prudent alternative calls for high steady releases in the spring, and low steady releases in the summer and fall, for low water release years in order to study effects on endangered and native fish. The effects of the endangered fish research flows were not evaluated in the GCD-EIS.[7]

Section 1803 of the GCP Act specifies that, following implementation of the ROD based on the final GCD-EIS, Glen Canyon Dam shall be operated consistent with section 1802 of the GCP Act. Reclamation’s GCD-EIS changes the long-term operating criteria at GCD, which will affect the magnitude and timing of electric power available under a range of possible hydrological conditions. The ROD was signed by the Secretary of the Interior on October 9, 1996.[8] In addition, further operational changes could be made in response to conclusions from adaptive management research and long-term monitoring.

2.2.7 SLCA/IP ELECTRIC POWER MARKETING EIS

In accordance with the provisions of the National Environmental Policy Act of 1969 (NEPA), Western began an EIS process to determine the environmental impacts of Western’s proposed changes to the level of long-term firm electric capacity and energy sales from the SLCA/IP.

Western produced a final EIS entitled *the Salt Lake City Area Integrated Projects Electric Power Marketing Environmental Impact Statement* (EPM-EIS).[9]

The economic and natural resource assessments in this EIS were based on a range of commitment-level alternatives for the SLCA/IP, which were combinations of capacity and energy that could feasibly fulfill Western's firm-power marketing responsibilities. The capacity commitment levels studied ranged from 550 MW to 1,449 MW, and the range of annual energy commitment varied from 3,300,000 to 6,200,000 MWh per year.

In addition, the EPM-EIS studied a range of operational scenarios for GCD, ranging from no fluctuation in water release volume, to high fluctuations. The modified operations at Flaming Gorge due to the USFWS Final Biological Opinion were reflected in the analyses conducted within the EPM-EIS. A range of operational release volumes were also studied for the Flaming Gorge and Aspinall Unit. Finally, various supply options were assessed, including combinations of electrical power purchases and hydropower operational scenarios. The EPM-EIS evaluated the impact of this range of commitment levels, operational scenarios and supply options on air resources, ecological resources, land use, recreation, socio-economics, visual resources, and water resources.

The post-1989 firm power commitment levels (1449 MW of capacity and 6,156,000 MWh of energy) was selected by Western as the SLCA/IP preferred alternative, following an extensive public process. The ROD in Western's EPM-EIS establishes Western's commitment level for its wholesale SLCA/IP firm-power contracts which expire in 2004. The ROD was signed by Western's Administrator on October 17, 1996.

2.2.8 FUTURE SLCA/IP OPERATIONAL CHANGES

Additional changes to the operating criteria for GCD, the SLCA/IP marketable resource, and future replacement resource demand could occur as a result of research and long-term monitoring at GCD, and future changes in resource decisions by Western's customers. Potential future changes in operations at other SLCA/IP facilities may also affect

Western’s customers’ resource decisions. Until it is established to what degree mimicking pre-dam flows helps native fish populations to survive, research flows will likely continue to be tested and/or implemented at SLCA/IP generating resources for the foreseeable future.

Some discussion of the current operations at the SLCA/IP facilities relevant to this study was provided earlier. The operating regimes at several SLCA/IP facilities, including Flaming Gorge, Blue Mesa, Morrow Point and Crystal dams of the Aspinall Unit; and GCD, have recently been altered due to potential impacts to downstream ecological, cultural and recreational resources. These modified release constraints, which typically prescribe water releases to mimic pre-dam river flows, have reduced the flexibility of dam operations and resulted in financial and operational impacts to Western’s customers. Potential future operational changes at GCD, Flaming Gorge and Aspinall are discussed below.

2.2.8.1 Glen Canyon Dam

Potential future changes to GCD operations include:

- recurring tests of beach building and habitat maintenance flows;
- adaptive management program special releases (endangered fish research releases);
- changes to Upper Colorado River basin depletions; and
- revised operational constraints.

2.2.8.2 Flaming Gorge

Flaming Gorge currently generates about 50 MW less than its maximum capability, due primarily to steady flows during winter as a result of the 1992 Biological Opinion. A revised biological opinion is scheduled to be issued in 1997. At that time, Reclamation will prepare a NEPA document, potentially an EIS, on the operation of Flaming Gorge Dam. Future operational constraints could contain provisions for continuation of exception criteria for emergency situations and system regulation and/or continuation of targeted flows at downstream locations (i.e, the stream gage at Jensen, Utah).

2.2.8.3 ASPINALL UNIT

Interest in changing operations to mimic pre-dam flows below Aspinall is based primarily on improved habitat for endangered fish species along with recreational considerations at the Black Canyon of the Gunnison National Monument. The USFWS favors an operational scheme that would allow native fish to be able to migrate and spawn in the Gunnison River upstream from its confluence with the Colorado River. Similar to Flaming Gorge, future operational constraints could contain provisions for continuation of exception criteria for emergency situations and system regulation and/or continuation of targeted flows at downstream locations (i.e, below the Gunnison Tunnel).

2.3 WESTERN POWER PURCHASES

2.3.1 CURRENT PURCHASING PRACTICES

The Replacement Resources Process is interrelated with, and dependent on, Western’s power purchasing authorities and practices. Pursuant to Reclamation Law, Western has the authority to purchase power reasonably incidental to the integration of Federal hydroelectric power generated at Reclamation projects. When establishing long-term firm capacity and energy commitment levels, Western considers many relevant factors, such as hydroelectric generator capability, transmission limitations, annual rainfall quantities and reservoir levels.

Because of the non-interruptible nature of its long-term firm capacity and energy commitments, Western must acquire power from others when its hydroelectric generating resources are unable to supply contractually guaranteed quantities of firm capacity and/or energy. When Reclamation’s monthly water release patterns are not sufficient to provide the capacity and energy needed for Western to meet its firm sales commitments, Western acquires short-term spot market power to meet its contractual obligations. With Western’s extensive transmission network across several western states, purchases or exchanges can be made with a large number of utilities and generating resources.

Western acquires power on the spot market on a short-term basis not only in response to shortfalls in hydroelectric generation, but for various other reasons, including the relief of operational constraints (such as transmission limitations) and variations in the cost of power. This is consistent with the standard operating practices of electric utilities. Purchases and exchanges also allow Western to diversify its generation risk, capitalize on short-term market differentials in supply and demand, and maximize the value of SLCA/IP resources. The overall effect of these purchases and exchanges is to provide Western flexibility to respond to customer needs during varying hydroelectric operating scenarios.

2.3.2 PURCHASE POWER POLICY

In response to the Department of Energy’s Office of Inspector General’s “ Report on the Inspection of Power Purchase Contracts at Western Area Power Administration” (May 1995), Western has implemented agency-wide changes in its policies for the solicitation, negotiation, award and documentation of power purchase contracts. Western has improved its power purchasing procedures to ensure that an open and competitive process appropriate to the circumstances is used, that rate reasonableness is examined, and that the acquisition process is fully documented. These policies and procedures are included in a Western-wide Purchase Power Policy adopted by Western on May 31, 1996. The Purchase Power Policy includes provisions for power purchase of short-term (spot-market and one year or less), mid-term (1 to 5 years), and long-term (greater than five years).

The Purchase Power Policy will serve as a general guideline for Western in purchasing replacement power. However, the Policy does not supersede the provisions of the GCP Act for firm power contracts.

2.3.3 CONTRACT AMENDMENT, REPLACEMENT POWER PURCHASES

Western has been working with a group of SLCA/IP firm-power customer representatives (the Contract Modification Team) to implement contract amendments in order to accommodate replacement power decisions, and to address other impacts of changed operations at GCD and other Western resources. The Amended Contracts establish a prudent long-term commitment level of sustainable hydropower (SHP) and address the replacement of GCD (and other facilities) power, either by Western (Western Replacement Power, or “ WRP”), or by customers on an individual basis (Customer Displacement Power, or “ CDP”).

2.3.3.1 SUSTAINABLE HYDROPOWER

Replacement power will be acquired as WRP, CDP, or a combination of the two, based on the preferences of individual SLCA/IP customers. The acquisition costs will be passed through to these individual customers and not included as part of the SLCA/IP wholesale firm-power rates. However, some replacement power acquired by Western could be included in the rates. The amount in this latter category will be determined by sustainable hydropower (“ SHP”), which will be the minimum aggregate level of long-term firm capacity and energy that will be provided by Western to all SLCA/IP customers through the contract period. The cost of purchases or exchanges by Western required to firm SHP during any future period will be included as part of SLCA/IP wholesale firm-power rates.

SHP has been determined initially as part of developing the Amended Contracts, and can be adjusted over the term of the contract. The short-term seasonal SHP levels for the SLCA/IP are based on a 25% risk level, using anticipated hydrological conditions for the next two and a half years, and are set at 941 MW for the winter season and 928 MW for the summer season.

A long term SHP has also been set for each season using a 10% risk level and the anticipated hydrological conditions through the end of the contracts. The long-term SHP level is 915 MW in the winter and 853 MW in the summer.

2.3.3.2 CONTRACT COMMITMENT

The contract rate of delivery is the maximum amount of capacity (with firm transmission) that can be scheduled by the SLCA/IP customer each season through the contract period, as set forth in the contract. The post-1989 commitment levels (1449 MW of capacity and 6,156,000 MWh of energy) was selected by Western as the SLCA/IP preferred alternative, following an extensive public process in the Electric Power Marketing EIS. The Contract Amendment discussed above will add the concepts of SHP and available hydropower (“AHP”). AHP represents the amount of hydropower that will be made available to each customer for an upcoming season. AHP will vary based on hydrological conditions between SHP (which would be the contractual floor for AHP) and CROD (which is the contractual ceiling). The amount of replacement power required will vary by season, depending on the level of AHP available to the customer in any given season.

2.3.3.3 REPLACEMENT POWER

Western expects to acquire replacement power (WRP) on behalf of SLCA/IP customers. The offer to acquire power for any upcoming 6-month season will be made twice per year in advance of each season. Periodically, but at least every three years, Western expects to also offer to purchase WRP on a long-term basis (i.e., more than one season). Based on the price of WRP, customers can authorize Western to make the purchase, or decline the offer.

Customers that do not contract for WRP may procure their own replacement power (CDP) up to their CROD. CDP can either be provided from a customer’s internal resources or, if acquired from an entity directly or indirectly interconnected with Western, may be transmitted by Western to the customer’s system. Delivery of CDP to customers is expected to be subject to available transmission capacity.

The critical issue which arises is the importance of Western obtaining a least-cost resource. Customers are expected to decide to request WRP, or to obtain their own replacement power (CDP), primarily on the basis of the WRP’s cost competitiveness. Therefore, it will be of paramount importance to Western and its customers to obtain resources at the lowest possible cost consistent with system-reliability and other constraints.

2.4 TRANSMISSION ACCESS AND PRICING

Western historically has had an open access policy for its transmission system. Western is not a federally-regulated utility under Section 206 of the Federal Power Act, but its power and transmission rates are subject to review by the Federal Energy Regulatory Commission (FERC) pursuant to a delegation order, and it is subject to the open access provisions of Section 211 of the Energy Policy Act (EPAct) of 1992.

2.4.1 ENERGY POLICY ACT SEC 211, 212 & 213

Prior to enactment of the EPAct, FERC's authority to order an electric utility to provide transmission service was extremely limited and was not applicable to federal power marketing agencies. Under most circumstances, this meant that a transmission owner did not have to provide a requested service and did so on essentially a voluntary basis. If an investor-owned utility agreed to provide service, the FERC regulated the rates for the service.

The EPAct amended the Federal Power Act, including the following revisions to sections 211 and 212, and adding 213:

> " **SEC. 211.**
>
> (a) Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant... [t]he Commission may issue such order if it finds that such order meets the requirements of section 212, and would otherwise be in the public interest...

SEC. 212.

(a) RATES, CHARGES, TERMS, AND CONDITIONS FOR WHOLESALE TRANSMISSION SERVICES -- An order under section 211 shall require the transmitting utility subject to the order to provide wholesale transmission services at rates, charges, terms, and conditions which permit the recovery by such utility of all costs incurred in connection with the transmission services and necessary associated services... [and] shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable...

SEC. 213. INFORMATION REQUIREMENTS

(a) * * *

(b) TRANSMISSION CAPACITY AND CONSTRAINTS ...the Commission shall promulgate a rule requiring that information be submitted annually to the Commission by transmitting utilities which is adequate to inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints."

These sections provide authority to the FERC to order transmission service in the interest of maximizing efficient use of transmission and generation, at rates that are compensatory. This expands the FERC's traditional authority to include publicly-owned utility systems and PMAs (including Western), and is causing profound changes to the FERC's policies toward transmission access, transmission pricing, and the structure of the entire electric industry.

2.4.2 FERC ORDER 888 AND 889

On April 26, 1996 FERC issued orders 888 and 889 concerning open transmission access on the nation's electrical grid. Order 888 addresses equal access to the transmission grid for all wholesale buyers and sellers, transmission pricing, and the recovery of stranded costs. Stranded costs are the investments made by utilities under the regulated environment that may not be recoverable in market-based rates in a competitive environment. Order 889 requires jurisdictional utilities that own or operate transmission facilities to establish electronic systems to share information about their available transmission capacities.

In response to these rulemakings, utilities are proposing to form Independent System Operators (ISO) to operate the transmission grid, form regional transmission groups, and develop open access same-time information systems (OASIS) to inform all competitors of the available capacity on their lines. Although not all parts of these FERC Orders apply directly to Western and the other PMAs, Western plans to comply with the principles of the Orders. [10]

2.4.2.1 Open Access Same-Time Information Systems

Activity in 1996 and early 1997 centered around establishing Open Access Same-time Information Systems (OASIS), also known as Real-Time Information Networks (RIN) or Transmission System Information Networks (TSIN), as outlined in FERC Order 889. FERC requires that electric utilities provide all transmission customers, including the transmission owner or controller, simultaneous access to transmission and ancillary services through an OASIS that would operate under industry-wide standards. Western's Desert Southwest customer service region has established an OASIS which the CRSP Customer Service Center will use to post the availability of CRSP transmission facilities and ancillary services.

2.4.2.2 Regional Transmission Groups

Regional Transmission Groups (RTG) are groups of utilities and power providers established to coordinate regional transmission issues and to comply with FERC Order 888. Western has joined two Regional Transmission Associations (RTA) that are subject to FERC regulation and intend to comply with the FERC Order 888. Western also plans to coordinate the planning of large transmission system additions through these groups.

The CRSP Customer Service Center is one of the customer service regions of Western which is a member of the Western RTA (WRTA) and the Southwest RTA (SWRTA), within the Western Systems Coordinating Council (WSCC) region.[11] Western's customer service regions are developing their respective comparability tariffs for filing with WRTA. In developing these tariffs, the FERC pro-forma tariffs will be used as a model.

Western is working on rules and procedures for the tariffs and intends to file them once customer consultation is complete. Meanwhile, the respective customer service regions will give WRTA information on their existing wheeling contracts and submit current prototype contracts plus rates. The CRSP Customer Service Center, along with its customers, will decide how to develop the comparability tariffs and will review the history and basis for the establishment of available transmission capacity (ATC). ATC is the portion of the Federal transmission system that is surplus to committed uses and may be made available to transmission requesters. ATC is also important for non-discriminatory transmission access considering the RTAs' obligations and FERC's open-transmission-access order.

The initial focus of the CRSP Customer Meetings was a Western briefing on its determination of ATC on the CRSP system. Customer involvement in developing comparable CRSP transmission tariffs was also requested, to include contract terms and conditions and transmission rates. Once finalized, these tariffs will be made available to other members of the RTAs.

2.4.3 TRANSMISSION ACCESS AND POWER MARKETS

The implementation of FERC Order 888 will allow increased transmission access, which will provide more options for power supply, including non-utility power suppliers such as power marketers, traders, and IPPs. The increased number and diversity of options in power supply should also increase competition and lower prices.

As a transmission provider and an entity purchasing power, the SLCA/IP will experience the effects of changed transmission access policies from both perspectives. Western is receiving new requests for transmission service on the CRSP transmission system, for which it must determine whether or not there is ATC. Its determination must account for a number of factors relevant to ATC, including the highly variable pattern of hydroelectric generation experienced over the years and the need to purchase varying amounts of replacement power from different suppliers. To ensure that the most cost-effective sources of replacement power can be utilized, the CRSP transmission system must retain adequate capacity, which may be jeopardized if the determination of ATC does not anticipate the location and amount of replacement power purchases.

While the transmission requirements of replacement power may complicate the determination of the CRSP system's ATC, it will likely improve the overall availability and pricing of replacement power to Western. Increased transmission access will allow many utility systems with surplus power, but without direct transmission interconnection to the CRSP system, to respond to Western's RFP if transmission capacity is available on intervening systems, as the pricing and other terms of transmission service will be known. Likewise, it will allow power marketers to act as intermediaries in offering replacement power to Western from a variety of electric systems and non-utility generators.

Having many entities able to transmit power from a large number of resources to the SLCA/IP will ensure competition, so that the acquisition of replacement power (as opposed to Western's direct participation in a generating facility) will be cost-effective. In addition, it will allow more flexibility in the timing and length of acquisition commitments.

In the past, with limited transmission access, purchases were often made for a longer term than was desirable from a cost and flexibility standpoint in order to lock-up transmission access when it was made available. The strategy of "locking-up" transmission will be less important due to the assurance that providing transmission service based on ATC will be mandatory, not voluntary, on every system. If one path becomes fully committed, there will likely be several other available transmission options. Increased transmission access will allow for shorter-term acquisitions, which will better match the need for replacement power without substantially increasing the risk that transmission limitations will drive up the effective cost by severely restricting the available resource alternatives, as often occurred in the past.

2.5 INTEGRATED RESOURCE PLANNING

Integrated resource planning (IRP) is a comprehensive planning approach that expands traditional resource planning, which is typically limited to matching loads and supply-side resources, to considering the overall effect a resource has on the total power system, including the environment, reliability, dispatchability, and fuel diversity. Demand-side management is another part of the integrated approach to resource planning.

The IRP process typically includes projecting future loads and resource needs, identifying resource alternatives, screening or ranking the alternatives, developing and evaluating resource plans, and risk or sensitivity analyses, resulting in the selection of a preferred resource plan based on least-cost principles. Developing specific planning goals or guidelines to use in the development of alternative resource plans is a critical first step in the IRP process. Once identified, these goals can then be used to guide the development of evaluation criteria, the selection of resource options, and the overall process.

In preparing an IRP, assumptions are necessarily relied on to represent various resources, including the amount and timing of their availability, and their cost, location, and associated environmental impacts. Assumptions are also made as to transmission availability, fuel pricing and reliability, and many other factors affecting power system cost and reliability.

In a resource acquisition process, the planning assumptions are transformed to factual information. For example, in response to a Request for Proposals (RFP), pricing terms may be stated in the proposal, with either absolute figures or a base price escalated with reference to a specific index. The typical result is that the resource options offered by a potential supplier in response to an RFP may only vaguely resemble the assumed resources and their characteristics used in an IRP by a potential buyer. Accordingly, it is important to distinguish between the results of an IRP and application of the Principles of IRP to a specific group of resource options.

In general, the principles of the IRP process used in making resource acquisitions are least-cost; consideration of all system impacts, risks, and environmental effects; and public participation.

2.5.1 ENERGY POLICY ACT

In addition to affecting transmission access as discussed above, the EPAct also addressed requirements for integrated resource planning. Section 114 requires that Western's utility customers prepare IRPs that meet certain minimum standards. Failure to prepare and submit an IRP could result in the reduction in a customer's firm-power allocation or a financial surcharge. Sections 201 and 204 of the EPAct further delineate the IRP requirements for Western's customers, as follows:

> " **SEC. 201. DEFINITIONS.**
>
> (1) * * *
>
> (2) The term 'integrated resource planning' means a planning process for new energy resources that evaluates the full range of alternatives... in order to provide adequate and reliable service to its electric customers at the lowest system cost.
>
> (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 services...
>
> **SEC. 204. INTEGRATED RESOURCE PLANS.**
>
> (a) * * *
>
> (b) CRITERIA FOR APPROVAL OF INTEGRATED RESOURCE PLANS.--The Administrator shall approve an integrated resource plan... if... 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 five-year action plan...
>
> (3) Designated 'least-cost options'... and explained the reason why such options were selected.

> (4) To the extent practicable, minimized adverse environmental effects of new resource acquisitions.
> (5) ... [P]rovided for full public participation...
> (6) Included load forecasting.
> (7) Provided methods of validating predicted performance ...”

2.5.2 ENERGY PLANNING AND MANAGEMENT PROGRAM

In April 1991, as part of Western’s planning for the many customer contracts due to expire in the next several years, Western proposed a comprehensive Energy Planning and Management Program (EPAMP). Western’s EPAMP covers the entirety of Western’s system and links power resource allocations to preference customers with long-term energy planning and efficient energy use through the preparation of IRPs.

Western proposed to develop an EIS on this process on May 1, 1991, and held public scoping meetings in June 1991. Western then developed alternatives to be studied in the EIS, which were discussed at public meetings during March and April of 1992. On October 24, 1992, the EPAct was signed into law, which requires that Western’s customers prepare and implement Integrated Resource Plans (IRP). Section 114 of EPAct also specified that NEPA requires Western to complete an EIS on actions implementing IRP requirements for its customers. The proposed EPAMP program was modified as a result of passage of the EPAct in 1992 to fully incorporate the Act’s provisions.

Western published the EPAMP-EIS on July 27, 1995. The ROD on EPAMP was published on October 12, 1995, [12] and the final program regulations were published on October 20, 1995.[13]

The first of the two major components of the program is the IRP Provision. This provision requires Western’s long-term firm-power customers to prepare IRPs, and includes a small customer exemption for customers with total energy purchases of less than 25 gigawatt-hours (gWh) per year.

The second major component of EPAMP is the Power Marketing Initiative (PMI). The ROD specifies that the extension period for contract allocations will be 20 years from the current expiration date, with adjustments possible with a five-year notice to customers. However, required changes in operations may be implemented immediately, with any lost power being replaced by purchases of other resources until allocation adjustments can be made under the five-year notice provision. In addition, the PMI calls for establishing a resource pool, with resource extensions initially including 96 percent of the current marketable resource.

The customer IRP requirement provisions of EPAMP are now effective for all Western customers. The first IRPs for most SLCA/IP customers were due to Western in November 1996. The PMI provision of EPAMP is initially effective only for the Loveland Area Projects and the Pick-Sloan Missouri Basin Program - Eastern Division. Western has initiated consideration of applying the PMI to the SLCA/IP. Information about the process to be followed will be published in the Federal Register.

2.5.3 WESTERN’S PRINCIPLES OF IRP

In June 1995, Western published its *Final Principles of Integrated Resource Planning for Use in Resource Acquisition and Transmission Planning* (“Western’s Principles of IRP”) in the Federal Register.[14] The Western’s Principles of IRP, developed in response to the EPAct, encompass the following concepts:

<u>Resource Acquisition Principles</u>:

- Consider a broad range of supply-side, demand-side, and renewable resource options
- Use a public process
- Develop resource evaluation criteria addressing resource cost, environmental impact, dependability, dispatchability, risk, diversity, and DSM verification
- Develop evaluation criteria to allow for maintaining the lowest possible customer rates consistent with sound business principles

- Ensure that resource acquisition planning is consistent with power marketing plans and associated contractual obligations
- Document resource acquisition decisions and make available to customers and the public

Transmission Planning Principles:

- Conduct early and wide public involvement
- Describe the transmission need and develop alternative methods for meeting the need
- Evaluate reasonable alternative methods for meeting the need using cost, general environmental impacts, and system reliability
- Make results of the preliminary evaluation available to the public
- Proceed with NEPA analysis, using data from preliminary analysis

These principles are guidelines for the Replacement Resources Process. Appendix A contains a complete copy of Western's Principles of IRP.

2.5.3.1 APPLICATION TO RESOURCE REPLACEMENT

As described in its October 1994 Replacement Resources Process Information Packet, Western will apply these Principles of IRP in the evaluation of replacement resources. As part of its integrated resource planning approach to identifying cost-effective replacement resources, Western will consider non-renewable conventional resources, as well as renewable resources and energy efficiency measures. Another important aspect of the IRP approach will be inclusion of the effects of resource type and location on Western's transmission system and overall system reliability.

However, Western's resource acquisition process will not be based on, nor be the equivalent of, a typical IRP. The resource acquisition process will be guided by Western's agency-wide Principles of IRP. Goals and objectives for the Replacement Resources Process will serve the same function as in an individual utility IRP. To the extent that Western acquires replacement power at the request of individual customers, this policy will also provide consistency between Western's replacement power acquisition process and the customer's IRP.

2.5.4 REGIONAL UTILITY IRPS AND RFPs

Recent regional utility integrated resource plans and requests for proposals were also reviewed as a part of the background research done for this report. Western intends to make use of the latest available methodologies and information on resource planning, along with the options available on the power market, in its Replacement Resources Process. Appendix B contains more detailed information on some of the regional utility IRPs and RFPs reviewed for this report.

ENDNOTES:

[1] The Collbran Project, which is integrated with the other SLCA/IP, but is not a part of CRSP, includes two powerplants, Upper Molina and Lower Molina. These power plants have a combined output of about 14 MW. The sole power feature of the Rio Grande Project is Elephant Butte Dam and power plant, with an installed capacity of 24 MW.

[2] At maximum reservoir levels, about 1000 megawatts of capacity would be available under the interim operating criteria, based on approximately 40 megawatts per 1,000 cfs.

[3] Off-peak hours are hours of lower electrical demand, generally at night and on weekends and holidays. On-peak hours are hours of high electrical demand, generally during daytime and evening hours on work days.

[4] In March and April 1996, Reclamation conducted a test of Beach/Habitat-Building flows at GCD. Beach/Habitat-Building flows are identified in the GCD-EIS as an element of the preferred alternative to be conducted approximately one year out of ten. The initial test was conducted to assess the effectiveness of a high release of short duration for rebuilding high elevation sandbars, depositing nutrients, restoring backwater channels and providing some of the dynamics of a natural river ecosystem. During the test, 213,000 acre-feet of water by-passed the GCD turbines, resulting in 105,000 MWh of lost generation. Preliminary results of the test provided by Reclamation indicate that the test was successful in restoring beaches and creating backwater habitats for endangered fish, but that a shorter release could achieve the desired results with a small loss of generation.

[5] *Operation of Glen Canyon Dam, Final Environmental Impact Statement*, U.S. Dept. of the Interior, Bureau of Reclamation, March 1995.

[6] *Biological Opinion, Operation of Glen Canyon Dam as the Modified Low Fluctuating Flow Alternative of the Final Environmental Impact Statement Operation of Glen Canyon Dam*, U.S. Fish and Wildlife Service, Arizona State Office, December 21, 1994.

[7] However, the effects of endangered fish research flows on summer capacity can be approximated by that of the Seasonally Adjusted Steady Flow alternative. Summer capacity would be reduced from 1,315 MW to 498 MW during years in which endangered research flows occur, while winter capacity and annual energy would essentially remain unchanged from those identified above for the final preferred alternative.

[8] Record of Decision, Operation of Glen Canyon Dam, Final Environmental Impact Statement, October 1996.

[9] *Salt Lake City Area Integrated Projects Electric Power Marketing, Final Environmental Impact Statement*, Western Area Power Administration, DOE/EIS-0150, January 1996.

[10] Western is currently reviewing its transmission pricing and contract terms for consistency with the orders. In addition, Western will continue to have rates approved by FERC and will develop standard contract offerings through a separate process.

[11] The documents signed by Western to join WRTA and SWRTA were: the WRTA Governing Agreement, signed by the Salt Lake City Area Office on 2/17/95, the Phoenix Area Office on 4/24/95, and the

Loveland Area Office on 5/23/95; and the SWRTA Bylaws, signed by the Phoenix Area Office on 6/8/94 and the Salt Lake City Area Office on 6/9/94.

[12] Record of Decision for the Energy Planning and Management Program, (60 FR 53181) October 12, 1995.

[13] Final Rules for the Energy Planning and Management Program, (60 FR 54151-54180), October 20, 1995.

[14] Final Principles of Integrated Resource Planning for Use in Acquisition and Transmission Planning, (60 FR 30533-30535), June 1995.