ANNUAL REPORT 2005

Western Area Power Administration

A path to the future

A path provides a sense of direction toward a common goal. Yet choosing the right path for the future can often be an organization's most difficult decision. In our 28-year history, Western has frequently had to make tough, occasionally soul-searching, decisions about which direction to take on everything from restructuring and reliability to policy and budgets. Sometimes the right path to choose hasn't always been clear, and we've cautiously taken one step at a time, not knowing which direction will move us forward. Other times the right path is just waiting to lead us where we want to go.

The Path 15 Upgrade Project was just such a journey. FY 2005 saw the culmination of this $250 million project, one of Western's largest transmission upgrade projects in a decade. The project's successful commissioning in December 2004—on time and under budget— validated that Western had chosen the right path in getting involved in this public-private partnership.

In FY 2005, Western faced decisions about other paths that would lead us into the future, such as those that would help us solve long-standing transmission constraints in our service area, show our increasing support of renewable energy or move us into a more complex technological environment. Our involvement with the Colorado Wyoming Transmission Project and Rocky Mountain Area Transmission Study, our renewable energy certificates program and management of wind studies and interconnection requests, as well as our fiber optic upgrades, are just some of the projects that continue to lead Western onto a "path to the future."

There are many paths Western could follow, but we will continue making the decisions to follow only those that keep us focused on providing reliable and cost-efficient hydroelectric power to our customers.

Contents

Western at a glance

Marketing profile

	FY 2005
Firm energy revenue	$691.7 million
Nonfirm energy revenue	$143.2 million
Firm energy sales	32.4 billion kWh
Nonfirm energy sales	3.1 billion kWh
Composite firm rate	21.02 mills/kWh
Coincident peak load (est.)	6,171 MW
Ancillary service revenue	$11.4 million
Transmission service revenue	$188 million

Customer profile

	Number	Sales (billion kWh)	Revenue (million $)
Municipalities	300	8.7	196.2
Cooperatives	66	7.1	156.1
Public utility districts	19	4.6	134.9
Federal agencies	36	1.3	36.4
State agencies	51	8.0	160.4
Irrigation districts	53	0.6	8.9
Native American tribes	87	1.0	18.3
Investor-owned utilities	25	0.7	32.6
Power marketers	29	1.3	61.9
Project use (Reclamation)	81	2.0	22.0
Interproject	4	0.2	7.4
Total	**751**	**35.5**	**834.9**
Firm-only customers	616[1]		
Nonfirm-only customers	74[2]		
Firm and nonfirm customers	61		

[1] Includes 81 project use customers
[2] Includes 4 interproject customers

Integrated Resource Planning profile

IRPs from individual customers	103
IRPs from cooperatives	34
Small customer plans	89
Minimum investment reports	85
Customers and members represented	822

Repayment profile

Principal repaid in FY 2005	$18.2 million
Federal (with adjustments)	$13.9 million
Non-federal	$4.3 million
Total investment	$5.70 billion
Federal	$5.50 billion
Non-federal	$0.20 billion
Total repaid	$2.93 billion
Federal	$2.87 billion
Non-federal	$0.06 billion

Financial profile (in millions)

Assets	$4,057,212
Liabilities	$505,131
Gross operating revenues	$1,059,447
Sales of electric power	$806,576
Other operating income	$252,871
Operating expenses	$1,020,919
Operation and maintenance expense	$318,206
Administration and general expense	$54,404
Purchased power expense	$478,951
Purchased transmission expense	$45,930
Depreciation	$123,428
Net interest expense	$166,920

Resource profile

Hydro powerplants	56
Thermal powerplant	1
Total powerplants	57
Actual operating capability July 1, 2005	8,785 MW
Total units	182
Net generation	25,195 GWh
Purchased power	11,676 GWh

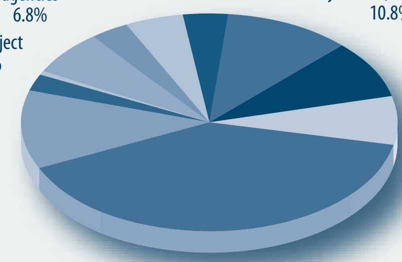
Transmission system profile

Communication sites	438
Substations	292
Transmission lines (circuit)	17,006 miles
Transformer capacity	25,672,680 kVA

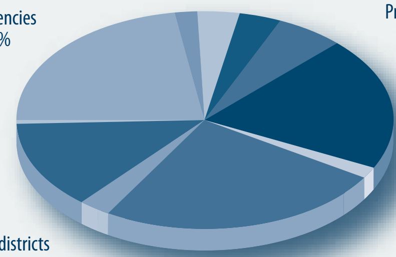
Employee profile

Federal full-time equivalent usage	1,334

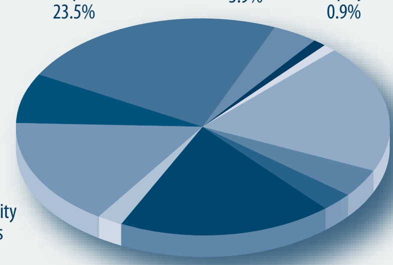
CUSTOMER MIX



WHERE OUR ENERGY GOES (kWh)



WHERE OUR REVENUE COMES FROM ($)



Administrator's letter

The Honorable Samuel L. Bodman
Secretary of Energy
Washington, DC 20585

Dear Secretary Bodman:

I am pleased to present to you Western's FY 2005 Annual Report, which focuses on Western's path to the future. Our path is lined with many challenges—aging equipment, cost containment, overcrowded transmission line corridors and increased purchase power costs—but we remain steadfast in our journey to provide our 751 wholesale customers with reliable and renewable hydroelectric power that helps them plan for their future.

In FY 2005, we sold and delivered 35.5 million MWh of reliable energy to our customers. This resulted in revenues from power sales totaling almost $835 million. The prolonged drought required us to purchase greater amounts of power in FY 2005 from other suppliers to meet our long-term firm power contract commitments. Congressional authority allowed us to fund these purchases from power sales receipts. This receipt funding authority, as well as our alternative financing programs, helped us manage our FY 2005 program budget of $1 billion with increased self-sufficiency. In fact, appropriations of $175 million made up only 17 percent of our authorized funding—the smallest percentage of our total funding sources in FY 2005.

By continuing to manage our costs and apply the right mix of resources and budget authorization, we ensure that our Federal hydropower program operates efficiently, even during severe drought cycles. This management of resources also allows us to continue to repay the U.S. Treasury for the Federal investment in the power facilities. In FY 2005, total repayment was more than $18.2 million.

Helping our customers, including new Native American tribal customers, to forge new paths of economic self-sufficiency is also one of our long-term goals. Ensuring that these tribes, as well as our other long-term customers, can rely on the delivery of cost-based hydropower is our main focus as we explore ways to help solve transmission constraints between Wyoming and Colorado; increase transmission system reliability by upgrading our communication backbone with fiber optics; and support renewable energy efforts, including wind generation. We highlight those projects in this year's report.

To guarantee that the grid provides reliable electric power, our path includes modernizing through smarter technologies, transmission upgrades and enhanced system coordination. One route we are taking in that direction involves a Technology Coordination Committee, which will steer how our agency implements new technology. This group recommends advances that best match Western's power system performance and operational practices. For example, Western has expanded the use of microprocessor-based devices to speed the diagnosis of power system disturbances and service restoration.

Such endeavors fit well with the goals of the Energy Policy Act of 2005. The Act authorizes new funding for research into cutting-edge technology. With this legislation, we can take part in building a modern 21st century electric grid. The proposed project to eliminate transmission constraints between Colorado and Wyoming may be one step to achieving that goal in Western's Rocky Mountain Region.

> *"To guarantee that the grid provides reliable electric power, our path includes modernizing through smarter technologies, transmission upgrades and enhanced system coordination."*

Building a modern grid calls for altering our path at times to accommodate restructuring changes in the electric utility industry, revised business practices and more stringent reliability standards. For example, we revised our Open Access Transmission Tariff in January 2005 to accommodate large generator interconnection procedures defined by the Federal Energy Regulatory Commission. We made changes to our general power contract provisions to refine our business practices. We also participated in Electric Power Research Institute work groups in FY 2005 to develop grid reliability metrics to prevent catastrophic outages like the August 2003 Northeast blackout. We are actively involved at both the national and regional levels, serving on reliability council committees to establish and enforce reliability standards.

The use of renewable energy has also taken on increasing importance. The new legislation calls for government agencies to include a greater percentage of renewables in the total amount of energy they consume. Western is meeting the President's goal of using more renewable energy in Federal facilities by purchasing renewable energy credits for "station service"—or energy we use for our own facilities. In August 2005, we teamed up with other Federal agencies to purchase more than 117,000 MWh of these credits, or green tags. Each green tag represents the intangible environmental benefits associated with generating electric energy by a renewable resource.

We have also renewed our focus on energy conservation. At our duty stations across the West, we have reduced energy use by turning off unnecessary lights, reducing air conditioning or heating use during early morning or late afternoon hours and emphasizing home energy conservation through our publications. And as always we keep our focus on safety in all projects we undertake.

We know that as a Federal power marketing administration, we have a role in blazing a path for others to follow.

Michael S. Hacskaylo

Michael S. Hacskaylo
Administrator

WESTERN PROFILE

Western markets and transmits about 10,000 megawatts of power from 56 hydropower plants. Western also markets the United States' 547-MW entitlement from the coal-fired Navajo Generating Station near Page, Ariz.

Western sells about 40 percent of regional hydroelectric generation in a service area that covers 1.3 million square miles in 15 states. Our customers include municipalities, cooperatives, public utility and irrigation districts, Federal and state agencies, investor-owned utilities (only one of which has an allocation of Federal hydropower from Western), marketers and Native American tribes. They, in turn, provide retail electric service to millions of consumers in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Key focus on transmission

Providing this diverse customer base with reliable transmission is central to Western's mission. Using an integrated 17,000 circuit-mile, high-voltage Federal transmission system, Western delivers reliable electric power to most of the western half of the United States. Since Western's inception in 1977, we have added more than 3,700 additional miles of lines to our system and managed hundreds of requests for interconnections. Yet, the endless stream of developments in the industry—regional transmission organization formations, changes in control areas and the emergence of Federal Energy Regulatory Commission regulations and policies—have further increased Western's challenges.

Western's rates

Western's role in delivering power also includes managing 10 different rate-setting systems. These rate systems are made up of 14 multipurpose water resource projects and one transmission project. The systems include Western's transmission facilities along with power generation facilities owned and operated primarily by the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the U.S. State Department's International Boundary and Water Commission.

Employees' dedication

While Western's role in the industry has evolved over the years, the dedication of employees at Western's 51 duty stations has not wavered. Employees scattered throughout Western's vast territory work around the clock to sell power, operate transmission and provide maintenance and engineering services. These duty locations include Western's Corporate Services Office in Lakewood, Colo., and four regions with offices in Billings, Mont.; Loveland, Colo.; Phoenix, Ariz.; and Folsom, Calif. We also market power from our Management Center in Salt Lake City, Utah, and manage system operations and maintenance from offices in Bismarck, N.D.; Fort Peck, Mont.; Huron, S.D. and Watertown, S.D.

Legislative authority

Congress established Western on Dec. 21, 1977, under Section 302 of the Department of Energy Organization Act. Under this statute, power marketing responsibilities and the transmission system assets previously managed by Reclamation were transferred to Western.

Financing methods

While Western receives appropriations from Congress each year to finance the operation and maintenance as well as construction and rehabilitation activities for many of our power systems, including the Pick-Sloan Missouri Basin Program, Central Valley Project, Parker-Davis Project, Fryingpan-Arkansas Project and the Pacific Northwest-Pacific Southwest Intertie Project, these appropriations provide only a portion of our funding. In fact, in FY 2005, appropriations of $175 million made up only 17 percent of our authorized funding—the smallest percentage of our total funding sources.

Other sources include 23 percent from power sale receipts, 20 percent from project-specific revolving funds and 40 percent from customer advances for construction, operations and maintenance and reimbursable work. With these other sources, Western's FY 2005 program budget was $1 billion.

Our appropriation also includes an annual contribution to the Utah Reclamation Mitigation and Conservation Account as specified in the Reclamation Projects Authorization and Adjustment Act of 1992. Existing legislation allows for the Colorado River Storage, Central Arizona, Seedskadee, Dolores and Fort Peck projects to operate with power receipts through a revolving fund. Boulder Canyon is financed through permanent appropriation of receipts from the Colorado River Dam Fund. Under the Foreign Relations Authorization Act for FY 1994 and FY 1995, a separate appropriation is provided to operate and maintain Falcon and Amistad project facilities for the International Boundary and Water Commission. We also do work for other Federal and non-Federal organizations under authority of the Economy Act, the Contributed Funds Acts and the Interior Department Appropriations Act of 1928.

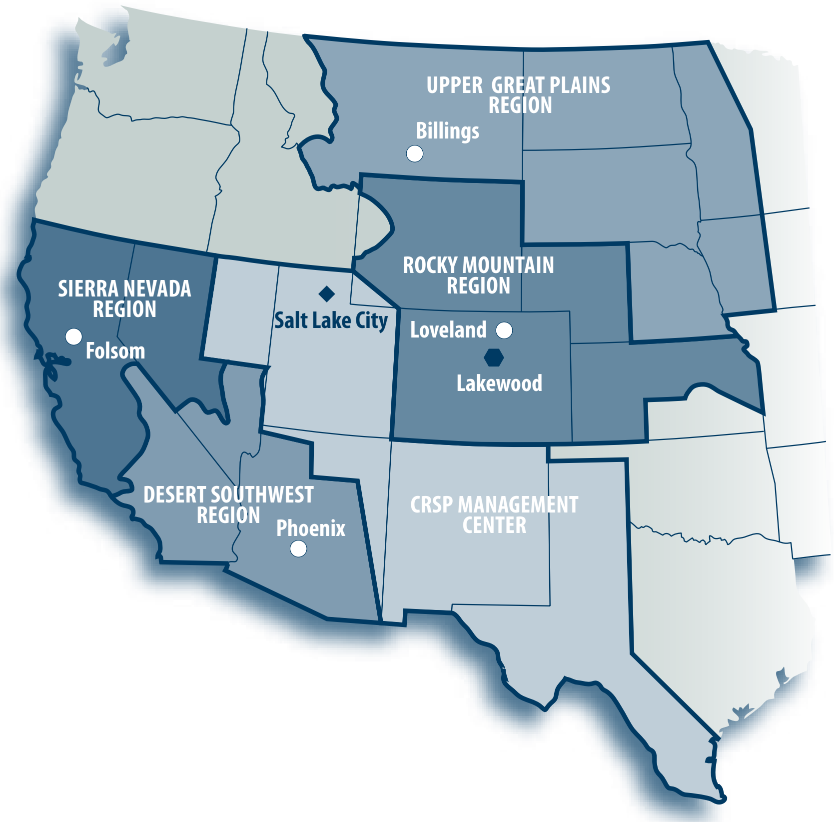
Because legislation requires that the U.S. Treasury be repaid by those who purchase our services, power sales must produce enough revenue to cover power users' share of annual operation and maintenance project costs. Therefore, we set power rates to recover all costs associated with our activities, as well as the Federal investment in the power facilities (with interest) and certain costs assigned to power for repayment, such as aid to irrigation development.

Power revenue is also used to fund Western's purchase power and wheeling activities. Drought conditions—like those we continued to experience in FY 2005—and other factors sometimes require us to purchase greater amounts of power from other suppliers to meet long-term firm power contract commitments. Since FY 2001, Congress has provided Western authority to fund these activities annually through the receipts we receive from selling power to our customers. The receipt funding authority, combined with traditional alternative financing methods, eliminated the need for an annual appropriation to meet planned purchase power and wheeling program needs.

In future budgets, we will likely see continued pressure on appropriations, leading to greater reliance on customers for alternative financing. Congress may pursue legislation to expand the use of power receipts beyond the purchase power and wheeling program to also finance operation and maintenance and program direction activities. In the near future, we may also see more non-appropriated financing for transmission facility upgrades and additions to reduce bottlenecks and improve reliability of the interconnected power grid. The Path 15 Upgrade Project is an example of how non-Federal financing within our existing authorities can be applied to improve the interconnected transmission system without the need for appropriations. This project was almost entirely non-Federally financed with no impact to Western's ratepayers. We will continue to emphasize the need for diverse, as well as stable, sources of funding in modernizing the transmission grid.

CUSTOMER SERVICE REGIONS

Regional boundaries
State boundaries
Regional office
Corporate Services Office
CRSP Management Center

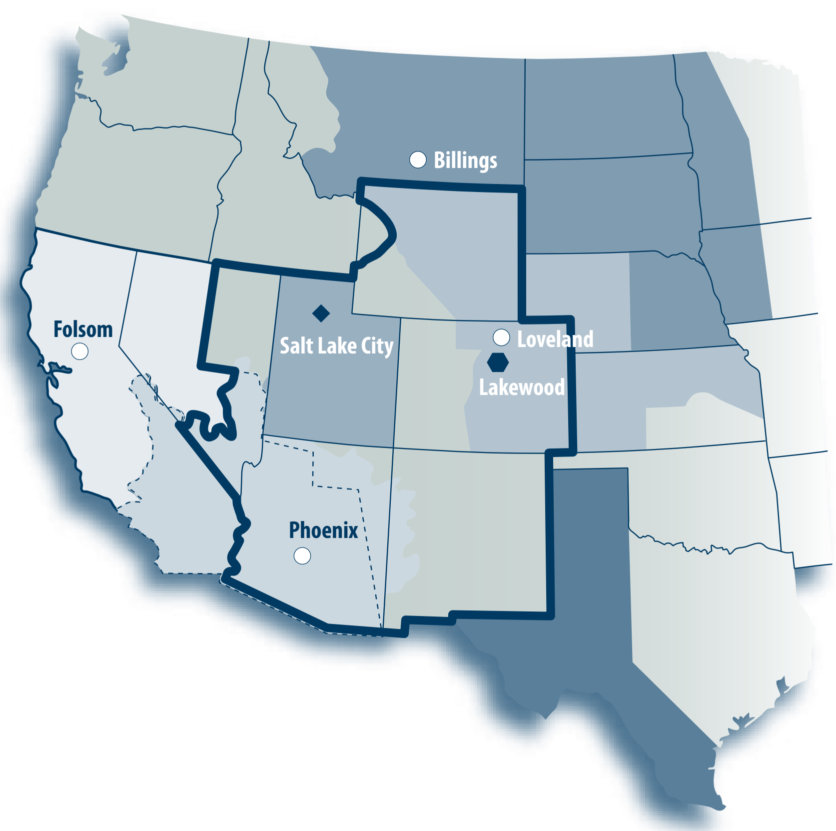


PROJECT MARKETING AREAS

MARKETING AREA BOUNDARIES

Central Valley and Washoe projects
Parker-Davis
Boulder Canyon and Central Arizona Project
Falcon-Amistad Project
Provo River Project
Loveland Area Projects
Pick-Sloan Missouri Basin – Western Division and Fryingpan-Arkansas Project
Pick Sloan Missouri Basin Program – Eastern Division
Salt Lake City Area/Integrated Projects
Colorado River Storage Project, Collbran, Rio Grande, Seedskadee and Dolores projects

State Boundaries
Regional Office
Corporate Services Office
CRSP Management Center



Renewables lead Western on 'greener path'

Sometimes the path to the future leads right to your own front door. Western's commitment to renewable energy starts with energy use at our own facilities.

For the next five years, Western facilities larger than 10,000 square feet will benefit from a purchase of 15,000 MWhs of renewable energy certificates from biomass and wind generation.

Renewable energy certificates, also known as RECs or green tags, are the intangible environmental benefits associated with generating one megawatthour of electric energy by a renewable resource. They don't require the energy to be physically delivered to the buyer, but instead offset the difference between cost of renewable power and power from conventional energy.

"We bought enough RECs to cover Western's 15 largest facilities and meet Western's renewable energy goals," said Western Technical Services Manager **Mike Cowan**. Western offices receiving credits from the purchase include maintenance offices, as well as regional offices, the Corporate Services Office and Electric Power Training Center. This purchase means Western met 100 percent of the energy needs of 85 percent of our workforce, while meeting the Energy Policy Act of 2005's goals of increasing renewable energy use government wide.

Partnerships for the future

Purchasing RECs to meet our renewable energy goals is fairly new, but Western's commitment to renewable energy is not. We have a long history of assisting customers in pursuing renewable resource opportunities and increasing energy efficiency.

We expanded on our strong support of the government's commitment to renewables by purchasing not only 15,000 MWhs of RECS for our own use, but by aggregating the purchase of a total of 117,000 MWh in August 2005 for 11 other Federal facilities.

Through our Renewable Resources for Federal Agencies Program, launched in 2004, we provide an opportunity for Federal customers, as well as other Federal entities, to meet their renewable energy goals by partnering with the Federal Energy Management Program and Western.

The certificates Western purchased in 2005 will come from renewable energy developers in our service territory, including biomass generation from the Sierra Pacific Industries' sawmill sites in Anderson, Lincoln and Sonora, Calif. Certificates also come from Nebraska Public Power District's wind farm in Ainsworth, Neb., and the Mountain View wind site in Palm Springs, Calif.

A simpler solution

Because Western facilitated the REC purchases, it simplified the process for program participants. "Western issued the RFP for the purchase and managed the contract with the supplier. We then will provide transfer certificates each year to the agencies," said **Peggy Plate**, RM's Energy Services representative who helped organize the purchase. "It saves these agencies time and dollars by consolidating work on these tasks."

It's important to note that the RECs Western purchased on these agencies' behalf were "Green-e certified," meaning they are certified to come from new renewable energy sources. "The primary purpose for purchasing RECs is to move new renewables

into the marketplace to displace fossil-based resources," said **Randy Manion**, Western's Renewable Resources Program manager. "When RECs are not certified, there is a risk that the tags are from renewable sources that have been doubly sold, are from older renewable generation facilities or are from renewable sources negatively impacting the environment."

By purchasing RECs, agencies can meet Federal renewable energy goals and help support the development of alternative renewable energy resources. Because no energy is physically delivered to the Federal site, there are no transmission or ancillary services required and no impact on existing power suppliers.

"It's easy and cost effective to get renewable energy certificates through this program," explained **Theresa Williams**, Western's Renewable Resources for Federal Agencies program manager. "We, at Western, are pleased to continue our commitment to support renewable energy."

General Engineer **Sam Loftin**, who helped coordinate the REC purchase for Salt Lake City Area/Integrated Project customers, added, "Western's purchase of RECs allows our customers to meet the requirements of the Energy Policy Act of 2005 directing Federal agencies to purchase a percentage of their power requirements from renewable resources."

Leading by example

By purchasing RECs for our own facilities and by encouraging other agencies to follow the same path, Western is setting an example for renewable energy use governmentwide.

"It's part of our stewardship role to find ways to reduce pollution," said Plate. "Renewable energy is not always readily available for some agencies, but it's part of the long-term solution for better air and water quality," she said.

At $1 a MWh, Western found the REC purchase to be economical. "The sale of these environmental attributes makes renewable energy projects economically competitive and less risky," said Plate.

Because Federal agencies are the largest purchasers of green tags in the United States, Plate said consolidated REC purchases make good business sense. "This stimulates the market for renewable energy in the West," she added. "It benefits our customers by having more clean resources in their communities, spurs economic development and decreases pollution.

"By working with our customers and evaluating new renewable energy opportunities, we can meet the Federal executive orders for energy efficiency and renewable energy, help Federal agencies achieve their goals of purchasing of renewable energy resources, and facilitate the transfer of information and renewable resource opportunities between industry and Federal power customers."

Project aims to solve transmission path constraints

Constant wind gusts shape the landscape and an abundance of coal reserves below ground make Wyoming rich in energy resources. Delivering those resources to growing populations to the south, however, is challenging due to a constrained transmission path called TOT 3, or Path 36.

To alleviate that bottleneck and to provide for the energy needs of growing populations in northern Colorado, Western partnered with the Wyoming Infrastructure Authority and Trans-Elect in FY 2005 to explore the feasibility of expanding the region's transmission system. This endeavor is the culmination of recent studies and reports pointing to the urgency of eliminating the transmission system constraints. The TOT 3 bottleneck was one of three high priority upgrades identified in the 2004 Rocky Mountain Area Transmission Study by a regional consortium of utility and industry representatives, energy developers and government agencies, including Western.

"Upgrading this path will allow increased opportunity to import low-cost resources to serve Front Range loads in Colorado," said Western's Rocky Mountain Region Restructuring Manager **Bob Kennedy**.

Building upon previous successes

An upgrade along the TOT 3 constraint could build upon the successful Path 15 Upgrade Project in central California, commissioned in December 2004. That public-private partnership among Western, Pacific Gas and Electric Company and TransElect led to the addition of an 84-mile, 500-kV line alleviating a transmission constraint between northern and southern California. The project demonstrated that public-private partnerships can resolve transmission bottlenecks.

"We've shown that the public and private sectors, bringing their respective strengths to a project, is an excellent approach to get the work done," said Western's Administrator **Mike Hacskaylo**.

Wyoming Governor Dave Freudenthal and the Wyoming congressional delegation recognize the benefits of a similar effort. In a March 2005 letter, Gov. Freudenthal urged Western to apply the success of the Path 15 public-private partnership to the TOT 3 constraint. "I am asking that you bring this model of Western's facilitation leading to utility and merchant investment in new transmission to bear on TOT 3," he said.

Western is a partial owner of existing capacity across, and the path operator of, TOT 3. WIA was formed in June 2004 by the state of Wyoming to facilitate expansion of the state's transmission system. Western's role is to provide technical assistance for feasibility studies, without project-related funding commitments.

To determine the options available to alleviate the TOT 3 constraint, Western entered into an agreement with the WIA and Trans-Elect in September 2005. Under this agreement, Western will examine possibilities to construct this project, including soliciting interest from entities seeking transmission rights on a new 345-kV line from northeastern Wyoming across TOT 3 between Wyoming and Colorado to Denver. The partners are encouraging entities to consider participating because interest in funding capacity expansions across TOT 3 is significantly less than the RMATS group initially envisioned. The project's estimated cost is $318 million.

"This public-private partnership is an innovative approach to strengthening the ties between the Colorado and Wyoming economies, and is an important step to implement a key recommendation of the Rocky Mountain Area Transmission Study," said Gov. Freudenthal.

"As was the case with Path 15, Western may be able to negotiate an additional increment of capacity on a new TOT 3 line beyond that accounted for by our direct costs of participation in the project. This extra incremental capacity would provide increased transmission revenue and could allow us to serve project use and preference customers more efficiently, thereby lowering costs to those customers," said Kennedy.

Pressing need for additional transmission

"By increasing the current path's capacity by 500 MW, TOT 3 could accommodate a combination of new wind and coal-fired generation capacity," said **Bob Easton**, Western's Rocky Mountain Region transmission planning manager. Eighty percent of Colorado's loads are south of this constrained path along the eastern edge of the Front Range between Fort Collins in the north and Pueblo in the south.

"We see a significant need for investment in the Rocky Mountain region to meet the growing demand for electricity to prevent shortages and support economic development," said Robert Mitchell, Trans-Elect's managing director.

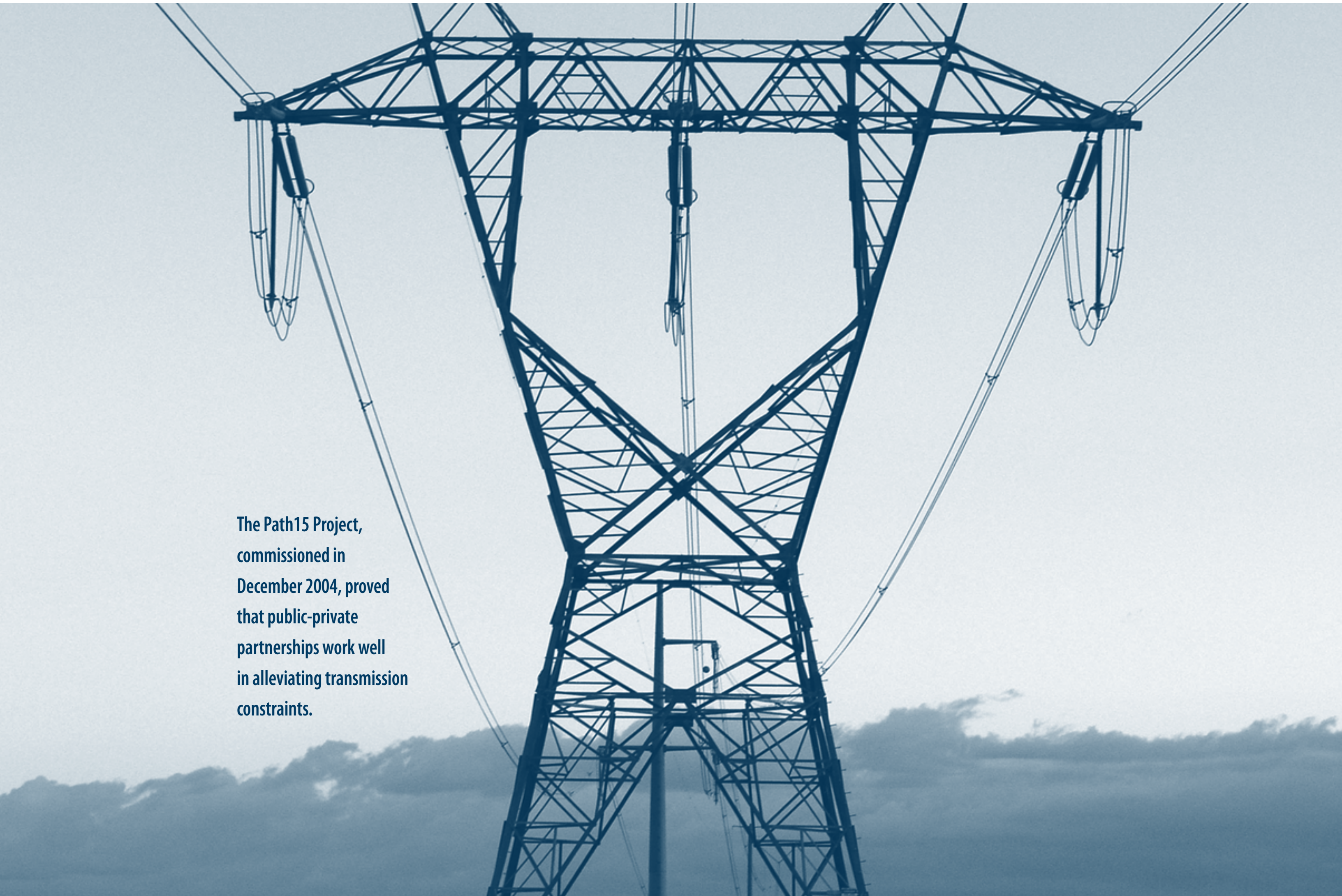
Where a new 345-kV line would interconnect with Western's system and when it would be completed are yet to be determined. The RMATS group speculated that the line could have substation interconnections in Casper, Wyo., at the Dave Johnston station, in Wheatland, Wyo., at the Laramie River Station and in the Cheyenne area. It would also require an interconnection in northern Colorado, perhaps at Western's Ault Substation, with a final destination near the Green Valley Substation northeast of Denver.

Adding new technology, or perhaps series compensation to this new line (and potentially other lines) could increase capacity by an additional 250 MW, bringing total capacity up to 750 MW. However, Kennedy cautioned that "the actual size of the line and the type and amount of generation likely will be dictated by the expressions of interest from, and what is ultimately purchased by, any Colorado loads."

"As with any path in the Western Interconnection, the new line must be rated to withstand the loss of the single worst contingency," said Easton.

In the near term, Western's maintenance plans will help alleviate this and other system constraints until a new line could be built. For example, Western plans to replace one of the aging Flaming Gorge 230/138-kV transformers in 2007; add transmission enhancements for the Animas-LaPlata pumping plant in 2008; upgrade the Miracle Mile–Cheyenne–Ault 115-kV transmission line to 230-kV in 2010; upgrade the Beaver Creek–Erie 115-kV line to 230-kV in 2010; and convert the voltage from 34.5-kV to 69-kV in the Platte Valley in 2015.

Kennedy and Easton believe that investing in the area's transmission system is needed. "Building a new TOT 3 line would be of benefit to Western through cooperative patrnerships with non-federal entities to construct transmission," said Kennedy.



The Path15 Project, commissioned in December 2004, proved that public-private partnerships work well in alleviating transmission constraints.

Wind studies pave path of system improvements

While interest in wind generation is increasing throughout Western's service territory, new insight gained from Western's Dakotas Wind Transmission Study will identify improvements to the grid to help deliver renewable resources to consumers.

In late FY 2005, final study results were being analyzed. Congress appropriated $750,000 in non-reimbursable funds for Western to perform the study to examine the local effects of adding 500 MW of new wind generation to the Dakotas' current transmission system. The study scope of work included four tasks: analyzing nonfirm transmission, assessing transmission technology relative to new wind generation , examining how new wind generation would interconnect to the existing transmission systems and analyzing how it would be delivered into the market. Western chose seven separate interconnection sites in North Dakota and South Dakota for the study based on public comments, wind resource maps, the Western Interconnection transmission queue, tribal projects and wind developer projects.

Western's goal was to move forward on the path of better understanding transmission system constraints and what portions of its Upper Great Plains Region transmission system could be used more efficiently. Western's study also analyzed emerging technologies that could increase the use of existing transmission lines.

"The results will help developers make business decisions involving wind development in the Dakotas, said Project Manager **Sam Miller**. "As renewable resources such as wind continue to grow in importance in Western's service territory, one imperative is to ensure improvements to the grid keep pace."

Final study results showed that for the seven wind sites studied, non-firm transmission is available most of the time across three monitored areas for up to 500 MW of new wind generation under normal system intact conditions. However, some of the sites are limited to less than 500 MW without additional system enhancements. The study indicated that some overloads and dynamic stability problems resulted when wind generation was added, but dynamic line rating and reconductoring could mitigate those problems without adding new transmission lines to the system.

"It was interesting to learn that non-firm transmission was available most of the time and should not be a constraint to hold back wind development," Miller said about the final results.

Better understanding to benefit developers

The 134 MW of wind generation currently interconnected to UGP's system accounts for about 2.5 percent of the energy consumed in the two states. But the current transmission system hampers delivery to other areas.

"Although the region already exports much of its existing generation, lack of adequate transmission capacity limits the amount of power that existing transmission lines can carry into other areas," said Miller.

Study task details

To shed light on ways to maximize the current transmission system in the Dakotas, study tasks 1 and 2 examined the possibility of transmitting additional wind energy on existing transmission lines when the lines are not physically congested or by managing power flow with new technologies. Tasks 3 and 4 evaluated the possibility of developing new transmission lines.

Task 1 examined how much transmission is contracted and how much transmission is actually scheduled hourly, daily and seasonally across three key corridors:

- 18 transmission lines in North and South Dakota and Minnesota, in the North Dakota Export Boundary
- Watertown-to-Granite Falls 230-kV transmission line
- Eight transmission lines east and southeast of Fort Thompson and west and northwest of Fort Randall, S.D.

Task 1 conclusions indicated that non-firm transmission capacity was available across the critical interfaces to transfer almost all of the wind energy for the 500 MW installed at any one of the seven sites.

"Wind power, as a variable, nondispatchable energy source, may be able to fit in the transmission grid during non-congested hours as an energy provider," said Miller. "I see a stronger market for non-firm transmission and something developers can take to their financial backers to bankroll future wind farm projects," Miller said.

Task 3 determined the local system requirements to connect proposed wind generation to the existing system and identified any local enhancements needed to accommodate new generation. The seven wind generation zones evaluated for interconnection were: Garrison, N.D.; Wishek/Ellendale/Edgeley, N.D.; Pickert, N.D.; Rapid City, S.D.; Mission, S.D.; Fort Thompson, S.D.; Summit/Watertown/Toronto/ White/Brookings/Flandreau, S.D.

Task 4 analyzed the firm transfer capability to ship power from wind sites to markets. Also analyzed were regional stability performance and limitations and the potential for some transmission technologies to increase power transfers from the Dakotas.

"Normal power flow on the transmission system often results in less than full use of the physical transmission capacity," said Miller. "One or more transmission lines may be loaded up to their thermal limits while the remaining lines are loaded to levels far below their thermal capacity. In the Dakotas, stability issues can limit transfer capacity before thermal limits are reached."

Since Tasks 3 and 4 indicated some steady-state and dynamic stability problems when wind generation was added, Task 2 provided an overview of some transmission technologies to mitigate overloads and stability problems without adding new transmission lines. To solve some of these issues, Task 2 considered the following technologies:

- Static var compensation to improve transmission system performance by providing reactive power to control dynamic voltage swings
- Series compensation to improve stability
- Phase-shifting transformers to improve stability and thermal loading by assisting with power flow control
- Dynamic line ratings to increase transfer capacity by calculating the transmission line's real-time, dynamic thermal rating based on real-time monitoring of lines and weather conditions
- Reconductoring to increase transfer capacity by replacing transmission line conductors with newer composite materials that can carry more current at the same or higher voltage. This evaluation included an assessment of impacts on existing tower structures and rights-of-way.

A static var compensation system, which Western has installed at the Watertown, S.D., Substation, was one of the technologies examined in the Dakotas Wind Transmission Study to determine how to mitigate overloads and stability problems when wind generation is added to the existing transmission system.

New technologies could reduce rates

Plugging into new technologies may help us more efficiently use the transmission system, which leads to lower transmission rates to rural customers, thus stretching their budgets further, Miller said.

Task 2 conclusions are that for overloading problems, dynamic transmission line rating and reconductoring the lines can mitigate problems. For dynamic instability and low voltage problems, series capacitors and static var compensation or static synchronous compensators can improve system performance.

"These cases demonstrate the improved performance by using technologies to help eliminate system constraints," concluded the report.

Final study results will be vital to renewable resource developers who are increasingly requesting interconnections and transmission service on Western's high-voltage lines.

"The wind industry, rural Dakotas and transmission ratepayers will all benefit from the study results. Western is setting a visible example for others to follow. The Dakotas Wind Transmission Study Report and acceptance of its findings by the public will reflect on Western's credibility as an organization and could result in big dividends that benefit our customers and ratepayers, "Miller concluded.

Path to the future includes upgraded communications

Western's path leads right to the latest advances in communication. To take advantage of higher-speed communications tools to remotely control our power system, in FY 2005 Western crews continued upgrading our microwave radio system with digital technology and fiber optics.

The upgrade project involves replacing the existing analog backbone communications network across Western's service area with a digital microwave radio or fiber optic system. Cables, made up of dozens of optical fibers protected by an outer layer of steel strands, replace one of the overhead ground wires typically installed on all Western transmission lines.

The fiber optic system also uses direct-buried cable, which has a plastic sheath instead of steel strands inside substations and in other locations where the overhead ground wire installation isn't practical.

"Optical ground wire is dual purpose cable that performs the duties of a ground wire—also known as a static wire," said **Dennis Graves**, Western's Upper Great Plains line crew foreman II who led his Rapid City, S.D.-based crew in installing fiber optic cable. "It also provides a path for voice, video or data signals by incorporating optical fibers into the design of the cable. Optical ground wire integrates easily into new and established high-voltage systems and is placed at the highest point on power utility structures, allowing for fast, cost-effective installations and extraordinary reliability."

An economical choice

"The challenge is staying ahead of obsolescence," said **Chuck Miller**, Western's Rocky Mountain Technical Support manager who helps manage the region's fiber optic upgrade project. "The projected lifetime of the fiber optic system is about 40 years. Compare that to 10 to 15 years for microwave radio equipment. In that timeframe, it seems that as soon as you are done upgrading your system, it's time to start all over again. We hope fiber optics give us more time," said Miller.

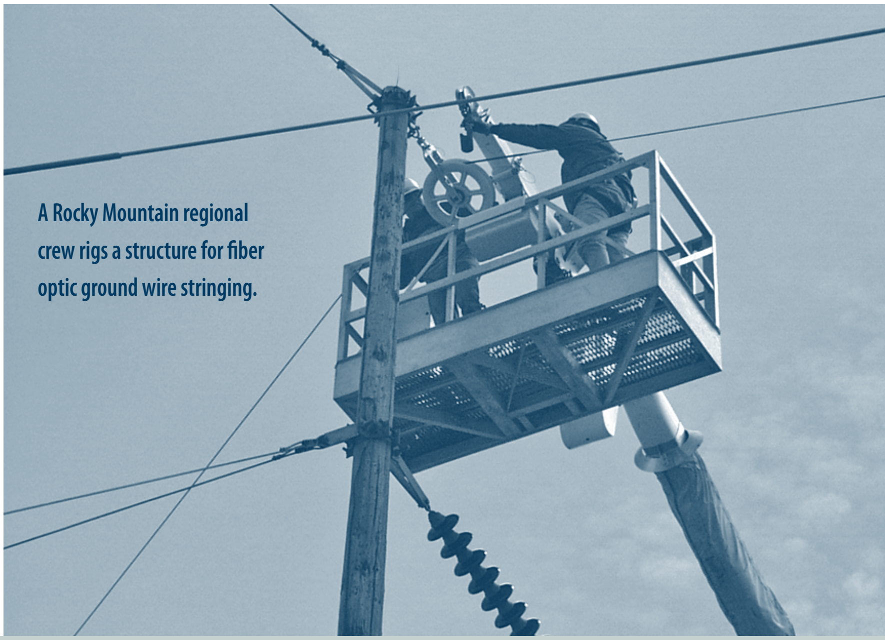
Besides a longer service life, fiber optics allow for a nearly unlimited number of radio channels that crews can use to communicate. Crews rely on Western's vast communication network to keep in touch while traveling to and working at job sites, to touch base with Dispatch and staff at their home duty stations, to communicate with neighboring utilities and to remotely monitor the transmission system.

"The communication system is used for controlling and monitoring the power system. It also provides communication among our various offices. As we improve and upgrade the communication system, the better and more tools we can provide to the employees as well as power facilities," said **Phil Sanchez**, an electrical engineer in Western's Sierra Nevada Region.

Upgrades allow Western to increase communication bandwidth, which translates into the ability to carry more information. "Some circuits require extremely high reliability or speed," said **Jim McHan**, lead electrical engineer.

Miller agreed. "Our communication needs are increasing. Everyone wants more communication channels. For example, we are being asked to install video cameras at substations for surveillance, which takes a lot more channels," he said.

"With fiber optics, we can install things like video surveillance and monitor substations remotely, which we couldn't do before, so we should also be safer," said **Terry Texley**, an electronics engineer in Western's Huron, S.D., office.



A Rocky Mountain regional crew rigs a structure for fiber optic ground wire stringing.

Upgrades provide opportunities

Western's current system includes a mix of analog and digital radio and fiber optic communication technologies. Besides using fiber optics to replace many of the current analog microwave radios—which turn sound waves into electrical vibrations of the same shape before they are transmitted—Western is also upgrading its communications backbone with digital technology, which samples an analog signal at short intervals and then turns it into numbers that are transmitted by the digital device and reconverted into an analog signal at the receiving end.

Projects to upgrade aging transmission lines and structures provide the best opportunity for Western to replace conventional overhead ground wire with fiber optic ground wire at a reasonable cost. In cases where we are rebuilding a line, it's not that much more expensive to replace the wire with fiber optics—only about 50 cents a foot more," Miller said.

Fiber optics use one cable to provide lightning protection for overhead power lines and a telecommunications network.

By the end of FY 2005, RM had replaced about 50 miles of overhead ground wire with fiber optics. In UGP, by fiscal year-end line crews were seven years into their 12-year project to change out the region's 3,000-plus miles of microwave paths. So far, crews have completed about one-half of the 3,000 miles. The communications replacement project should be complete across Western in 2010.

The Desert Southwest Region was the first to migrate to a digital Very High Frequency radio system. The region is also now beginning to establish a fiber optic program when reconductoring lines. Replacing the region's current analog microwave system is vital because the system is no longer being supported by vendors, and finding replacement parts is proving more difficult, say DSW electronics engineers.

The benefits to upgrading the system are a better digital communications system and the ability to carry more data and be ready for future substation automation, said **Sylvia Perez**, lead electronics engineer at DSW.

In the Sierra Nevada Region, Western and the Bureau of Reclamation have jointly taken advantage of fiber optic capabilities. SN and Reclamation own and share fiber optic cables, microwave radio systems and leased telephone circuits in Northern and Central California. The region jointly owns one 36-fiber optic cable with Reclamation. Western maintains the cable and Reclamation shares in the maintenance cost for major repair or cable replacement.

"As a result of the rapid changes in communications technologies, new opportunities are opening up to SN for use in meeting its communications requirements," said Sanchez. "The most important of these changes are significantly improved cost and reliability of leased circuits; possible partnerships for fiber optic installations and greater interest in sharing communication facilities with customers, connected utilities and others," he said. The long-range plan for the region is to interconnect Western's major facilities with high-capacity digital service.

"Western needs reliable communications to control our own power system and to communicate with neighboring utilities," explained RM Joint Microwave Project Manager **Kevin Hogg**.

Miller said technological advances continue to expand Western's communication options. "Fiber optics allow us to do more things than in the past," he said. "With higher-capacity communication, we can network substations together electronically into a Wide Area Network so you could access a remote substation from your desktop to monitor the status of equipment and diagnose problems. Right now, our SCADA system has alarms indicating when something fails or is getting ready to fail. With desktop access using fiber optics, we could monitor trends and potentially forecast future problems or maintenance needs. It will provide many new preventative maintenance opportunities," he said.

2005 ACCOMPLISHMENTS

Engineering

California earthquake research working group initiated

Western joined an earthquake research working group headed by the California Institute for Energy and Environment to help improve the seismic performance of transmission lines and substations in California. The California Energy Commission provided about $2 million per year for earthquake engineering research. The group is identifying weaknesses in the transmission system, suggesting research projects to improve these weaknesses and evaluating proposals from research agencies. This group will help ensure that Western's transmission system is as secure and reliable as possible, especially against the forces of Mother Nature.

Environment

Multi-Species Conservation Program agreement signed

Western staff, Interior agency representatives and the governors of California, Arizona and Nevada signed an agreement during a ceremony in April 2005 to protect numerous natural resources along the lower Colorado River Basin. The Secretary of the Interior hosted the ceremony to commemorate the signing of the Lower Colorado Multi-Species Conservation Program—a coordinated, comprehensive, long-term multi-agency effort to conserve and recover endangered species and to protect and maintain wildlife habitat on the lower Colorado River. The program would create more than 8,100 acres of riparian, marsh and backwater habitat for four listed species and 16 other species native to the lower Colorado River. By joining the agreement, Western gained approval to operate and maintain our facilities in compliance with the Endangered Species Act over the next 50 years.

Sacramento voltage support preliminary work started

Western reached agreement in January 2005 with the Sacramento Municipal Utility District for the district to provide $630,000 to complete pre-design activities and field data for a proposed double circuit 230-kV transmission line between Western's O'Banion Substation and SMUD's Elverta and/or Natomas substations in central California. The city of Roseville contributed an additional $70,000. The proposed transmission line was the preferred alternative identified in a 2003 environmental impact statement that studied possible solutions to resolve voltage support problems in the Sacramento area. Western is now doing field surveys and determining what additional environmental compliance work is needed.

Vietnamese environmental program supported

Western environmental staff met with a delegation of their Vietnamese counterparts both at Western and in Vietnam to exchange information about how to manage and address polychlorinated biphenyl contamination issues. After the Vietnamese utility workers and government officials visited Western's office, Sept. 16 and 17, 2004, as part of a tour arranged by the U.S. State Department and the Vietnamese government, a Western environmental manager traveled to Vietnam in April 2005 to provide assistance in setting up and implementing a PCB management program. PCBs were used in utility operations and now must be contained and cleaned up to prevent environmental harm. Western has significant experience in managing PCBs, and staff previously served on a State Department team providing support in Vietnam.

Human Resources

Career Progression Program launched

Western launched a 12-month, self-directed Career Progression Program in FY 2005 to help employees develop career paths and prepare for future roles, while helping Western retain knowledge in crucial job skills. The program helps entry-level employees develop skills and related competencies that will prepare them to compete for new types of positions, if and when they become available. The program is one aspect of succession planning efforts at Western to cope with expected retirements. Roughly 38 percent of Western employees were eligible for retirement at the end of calendar year 2005.

First Emerging Leaders Program class graduated

The first 20 participants in Western's Emerging Leaders Program graduated from the year-long developmental program on Feb. 18, 2005. The competitive program teaches non-supervisory employees about the competencies and leadership skills required for target positions and also broadens their knowledge of Western's mission and vision in an ever-evolving utility industry. The ELP is one of three developmental programs that will prepare Western employees for supervisory and managerial positions.

Maintenance

National Fire Plan Award received

Western's Western Colorado Maintenance Office staff and representatives from the Bureau of Land Management, U.S. Forest Service and other cooperating agencies received a National Fire Plan award in February 2005 from Interior Assistant Secretary Lynn Scarlett and Agriculture Assistant Secretary Mark Ray for their work on the Uncompahgre Plateau Project. The award was for the work by project participants in reducing fire problems on the western Colorado plateau, including removing tall, hazardous trees and reducing fire hazards along power line rights-of-way. This work has led to the improvement of the ecosystem as a whole, including thinning vegetation that attracts more diverse wildlife to the right of way.

Operations

Continuing Education Provider status granted by NERC

The North American Electric Reliability Council awarded Continuing Education provider status to Western's Rocky Mountain Region in FY 2005, joining the Upper Great Plains Region that received the status in FY 2004. This action also confirms that Western's Electric Power Training Center courses meet NERC requirements for dispatcher professional development. As a NERC-approved Continuing Education provider, Western can develop and deliver training that allows students to earn continuing education credits. Western will use this status to provide dispatcher training to assist in maintaining NERC system operator certification. Courses include: Interconnected Power System Operations; Western Electricity Coordinating Council/ Minimum Operating Reliability Criteria System Operator Training; North American Electric Reliability Council Dispatcher Certification Preparation; Real-Time Operations and Reliability Readiness; and Relaying for Operations Personnel.

New subcontrol area under SMUD implemented

Western successfully switched its Sierra Nevada facilities over to subcontrol operations under the Sacramento Municipal Utility District's control area on Jan. 1, 2005. As a contract-based subcontrol area operator, Western manages the physical flow of electricity for project use loads and to customers directly connected to Western's nearly 1,000 miles of transmission lines in northern California.

Post 2004 Operations implemented

When long-standing contracts with Pacific Gas and Electric Company expired on Jan. 1, 2005, SN began serving its customers under a new power marketing plan and operational configuration based on successor arrangements. These arrangements, including ones with the California Independent System Operator, were approved by the Federal Energy Regulatory Commission. Western now provides firming energy and ancillary services for project use loads and full load service customers, services that PG&E previously provided. Western coordinates with the Bureau of Reclamation and customers to develop generation schedules and load forecasts for project use loads and customers.

SCADA System upgraded

Under a partnership created in October 2004, Western and Southwestern power administrations are updating SWPA's aging Supervisory Control and Data Acquisition system, while Western and SWPA look into a future of shared system development backups and reliability. The SCADA system that Southwestern and Western are now sharing will improve grid reliability as both agencies will have full freedom to make changes rapidly to respond to power industry requirements or system emergencies. The cooperative effort also allows the agencies to provide backup resources for each other in times of crisis.

Student dispatch program launched

Finding and shaping the right people to become reliable system operators is the goal of Western's new Dispatcher Trainee Program, launched in FY 2005 at Upper Great Plains' Watertown office. Through the Dispatcher Trainee Program, two students enrolled at Bismarck State College in North Dakota working toward a two-year degree in electrical and transmission system technology get hands-on training and experience at Western, while taking online courses to learn the theory behind the process. After two years, participating students will take the North American Electric Reliability Council Certification Exam. If there's an opening for a dispatcher, they can be converted to career status and hired for the vacant position. With this program, Western can customize training of future dispatchers so that they are familiar with the unique aspects of Western's system.

Western recognized as NERC example of excellence

The North American Electric Reliability Council recognized Western's UGP Control Areas in its "Examples in Excellence" program for using electric industry practices that NERC identifies as exceptionally effective in protecting reliability of the interconnected bulk electric system. NERC recognized Western for our approach to monitoring frequency from multiple locations across our large service territory. Western's Upper Great Plains Region operates two control areas—one in the Midwest Reliability Organization Region (Eastern Interconnection) and one in the Western Electricity Coordinating Council Region (Western Interconnection). Operators monitor frequency at 148 locations and display 38 of these quantities on a single display representing a geographical map of these two control areas.

Power Marketing

Final allocations awarded for Pick-Sloan customers

In October 2004, Western announced final allocations to three customers from the Post-2005 Resource Pool of the Pick-Sloan Missouri Basin Program—Eastern Division. Auburn, Iowa will receive 128 KW of summer capacity and 147 KW of winter capacity; Pocahontas, Iowa, will receive 1,052 KW of summer capacity and 1,072 KW of winter capacity; and Montana State University—Bozeman, will receive 2,113 KW of summer capacity and 3,072 KW of winter capacity. The 15-year allocations come from a Federal power resource pool of Pick-Sloan's long-term marketable resource that becomes available Jan. 1, 2006.

General Power Contract Provisions revised

Western's marketing staff revised our General Power Contract Provisions to incorporate new standard provisions and to update existing provisions to comply with recent changes in the electric utility industry and new business practices. The GPCPs are a compilation of generally applicable contracting provisions that are typically included in new or amended contracts between Western and its customers. Western published final GPCPs on June 15, 2005. Western conducted an informal consultation process in each region to solicit customer comments on proposed changes during the two-year revision project. The updated GPCPs include revised provisions on delivery of service, rates, billing and payment, power sales, transfer of interest, choice of law and other provisions, such as liability and authorization contingencies. The newly adopted provisions will be phased in over time as Western's power contracts are revised or amended.

New firm power allocations offered to tribes

Because Western is committed to serving Native American tribes, we began delivering hydropower benefits to new tribal customers as we implemented the Energy Planning and Management Program's Power Marketing Initiative for the Salt Lake City Area/Integrated Projects. On Oct. 1, 2004, 57 tribes in the Salt Lake City Area/Integrated Project's marketing territory and five tribes in Rocky Mountain's marketing area became eligible to receive the benefits of Federal power from Western. Add to that the four tribes in the Sierra Nevada Region that began receiving Central Valley Project power allocations in January. These new tribes, as well as existing Native customers, bring the total number of tribes Western serves to 87.

Parker-Davis Project Remarketing effort developed

In FY 2005, Western announced the availability of firm power allocations from the Parker-Davis Project's long-term marketable resource and began seeking applications from entities interested in this resource pool, which becomes available Oct. 1, 2008. Under Western's Energy Planning and Management Program, we plan to allocate under 20-year contracts for long-term firm power an available resource pool of about 17 MW of summer season capacity and 13 MW of winter season capacity. Qualified applicants must be preference entities as defined by section 9(c) of the Reclamation Project Act. First consideration will be given to qualified applicants in the marketing area who do not have a contract with Western for Federal power resources or are not a member of a parent entity that has a contract with Western for Federal power resources.

Safety

Safety program focuses on working safely

Western employees and managers continued to focus on working safely in 2005. In April, Western employees were once again recognized our continuing commitment to working safely by the American Public Power Association. Western earned an honorable mention for utilities with 2 million to 4 million worker hours in APPA's annual safety contest.

Western's annual Bonus Goal program included three safety goals:

- Nine or fewer injuries resulting in lost work days
- 227 or fewer lost work days
- 8 or fewer recordable motor vehicle accidents

In Bonus Year 2005, employees reached two of the three safety bonus goals with eight injury accidents and seven motor vehicle accidents, making each eligible for an award payout of $333. However, to help accommodate unplanned congressional earmarks, Western's senior managers suspended bonus goal payments for FY 2005.

Fall protection, tree trimming practices examined

The goal of decreasing lost workdays due to accidents eluded Western in 2005, with employees recording 433 lost work days during the bonus year. In response to a fall accident suffered by a line worker in early October 2004, a team of experts was commissioned to review Western's fall protection program as it related to this accident to determine if any changes needed to be incorporated. The team made several recommendations to improve practices related to preventing falls from wood pole structures. All have now been adopted.

Western also took action in 2005 to ensure our tree trimming practices are as safe as possible. With increasing focus on outages caused by vegetation encroachments in rights-or ways, Western developed communication tools to share with landowners on trees and powerline right-of-way safety. We also updated our tree trimming procedures to protect employees from injuries while maintaining rights-or way.

Coloring contest brings health, safety home

Safety at Western isn't solely focused on on-the-job activities, although workplace safety is the primary emphasis. An annual safety coloring contest for employee's children and grandchildren brings the health and safety message home. The 2004 theme echoed a continuing focus on healthy lifestyles as a contributor to workplace safety.

More than 175 young, aspiring artists pulled out their pens, pencils, crayons and glitter to illustrate the importance of proper diet and exercise. Winners from each of the five age categories received blue ribbons and their choice of a $50 U.S. Savings Bond or a $40 check. All other contest participants received small prizes for entering the contest.

Transmission

Open Access Transmission Tariff updated

Western filed a revised Open Access Transmission Service Tariff on Jan. 25, 2005, with the Federal Energy Regulatory Commission. Western updated certain provisions to our previous tariff, which was completed in 1998, adopted the principal features of the Commission's Standard Large Generator Interconnection Procedures and Standard Large Generator Interconnection Agreement and made additional changes to further Western's mission and transmission marketing efforts.

Path 15 commissioned

Western commemorated the energization of the Path 15 Upgrade Project Dec. 14, 2004, at the California Independent System Operator's Folsom control center. Western's Administrator **Mike Hacskaylo** joined Calif. Gov. Arnold Schwarzenegger, then DOE Deputy Secretary Kyle McSlarrow and other state and Federal officials in commissioning the 500-kV transmission line, which now operates as part of California's power grid. The $250 million Path 15 Upgrade Project involved building a third transmission line and completing other work to relieve an energy bottleneck between northern and southern California. The project was built under a unique public-private partnership to increase transfer capacity within the strategic transmission corridor in central California by 1,500 MW, or enough to provide power to 1.5 million homes.

Sale of long-term non-firm transmission now offered

Western completed its first long-term non-firm transmission sale in the Rocky Mountain Region to the Municipal Energy Agency of Nebraska in May 2005. This offering will assist renewable developers with acquiring transmission that would not normally be available on a long-term basis due to transmission constraints. Western defined business practices for this yearly non-firm product, including available transmission capacity, rates, application fees and credits. On May 13, 2005, Western approved two transmission requests from MEAN to provide 40 MW of yearly non-firm transmission capacity. Expected revenue from this sale is about $540,000.

Western joins EPRI team for grid reliability metrics

Western staff are serving on an Electric Power Research Institute team on transmission grid reliability metrics. The team is defining a set of transmission system reliability metrics and supporting definitions for industry comparability, internal decision making and regulatory policymaking. After agreeing on metrics that measure the frequency and duration of transmission outages and transmission availability, as well as recommending a second phase to investigate how to standardize metrics among utilities with inherent system differences, the team issued its final report to the 29 participating North American utilities in summer 2005. This team's work will standardize how utilities' reliability efforts are measured and will ultimately help ensure a more reliable bulk interconnected transmission system.

FY 2005 IRP Summary

Western's Integrated Resource Planning requirements based on Section 114 of the Energy Policy Act of 1992, give customers several options to meet or streamline these requirements. The requirements, updated in 2000, recognize the changes occurring in the utility industry and our customer's varying size and structure. These changes also streamlined the reporting requirements without sacrificing the EPAct's intent.

Customers must submit annual progress reports and new integrated resource plans every five years, and may now submit them individually or cooperatively when they belong to member-based associations.

The IRP regulations allow customers to set action plan timelines (instead of a five-year minimum) to better correspond with their own situations. The regulations require only a brief summary verifying that one was conducted. Customers can submit a brief description of measurement strategies for the options identified in the IRP.

Western also made changes to IRP alternatives. Members of member-based associations and joint action agencies may now file a small customer plan if their sales/use is under 25 GWh per year.

Another alternative to the IRP is the minimum investment report. Customers required by a state, tribal or Federal regulation to make minimum financial/resource investment in demand-side-management or renewable programs may file a minimum investment report consisting of an initial report and an annual letter.

All firm power customers have submitted one of these options. In FY 2005, Western received 103 IRPs from individual customers, 34 plans from cooperatives, 85 minimum investment reports and 89 small customer plans. These plans represent 822 long-term firm power customers and customer members.

Customer-reported trends include:

- Increased demand for renewable energy technologies in all (commercial, industrial, residential and institutional) market segments
- Increased requests for education and information transfer on energy efficiency and renewable energy technologies
- Water management, efficient use, conservation, irrigation and pumping efficiency
- Continued re-emergence of demand side management efficiency activities/programs
- Key accounts programs, tools and training

The most frequent demand side management activities cited by Western's customers are:

- Lighting technologies
- HVAC technologies with emphasis on cooling and ventilation
- Audits for residential, commercial and industrial facilities
- Load management
- Weatherization

The top five renewable energy resource choices are:

- Hydro (large & small)
- Wind generation
- Solar – PV
- Geothermal
- Biomass/gas

IRPs are driven by customer need and requests. Cost and reliability are still the highest priority, but factors such as renewable energy technologies have an ever-increasing influence on both of them. Additional factors include: foreign energy dependence, environmental issues, security issues, developing technologies, affordable options and regulations.

FY 2005 Customer IRP Accomplishments

Item	CRSP MC	DSW	RM	SN	UGP	Totals
DSM[1] kW savings	14,417	121,445	109,307	73,705	409,838	728,712
DSM kWh savings	84,145,788	146,697,173	76,748,890	165,881,875	183,192,372	656,666,098
DSM $ expenditure	14,298,417	31,683,101	4,689,986	61,327,968	19,394,709	131,394,181
kW renewables	114,496	471,258	73,371	70,240	239,629	968,994
kWh renewables	268,544,665	674,788,211	192,311,434	403,434,494	392,311,087	1,931,389,891
Renewable $ expenditure	6,475,780	5,879,417	10,184,472	9,337,860	575,857	32,453,386
Most frequent DSM activities	Commercial/ industrial lighting, HVAC, domestic hot water, irrigation	Pump motors, commercial/ Industrial HVAC, compressor reduction, building operations management	Residential audits, lighting, LEED, commercial audits, HVAC, motors	Residential lighting, pump repair/ replacement, water management, residential, weatherization, commercial HVAC	Load management, lighting, weatherization new construction motors/pumps	Lighting, HVAC, audits, load management, weatherization
Top renewable energy activities	Solar, wind, small hydro	Wind, solar	Wind, hydro	Small hydro, geothermal, PV, methane	Large wind small wind PV, hydro	Wind, solar, hydro, geothermal, biomass/gas
Top customer reported trends	Renewables, efficiency, audits	Renewables, pump efficiency	Customer demand for renewable energy, residential efficiency, key accounts, DSM programs	Pump upgrades, water management, residential efficiency, commercial efficiency	Renewable energy programs, capital/cash constraints	Renewables, efficiency, key accounts

[1] Demand-side management

Repayment summary

Western Consolidated Status of Repayment (Dollars in millions)	Cumulative 2004	Adjustments	Annual 2005	Cumulative 2005
Revenue:				
Gross operating revenue	21,449	19	1,072	22,540
Income transfers (net)	(1,120)	(1)	(120)	(1,241)
Total operating revenue	**20,329**	**18**	**952**	**21,299**
Expenses:				
O & M and other	7,440	(10)	374	7,804
Purchase power and other	6,389	19	537	6,945
Interest				
Federally financed	3,618	7	155	3,780
Non-Federally financed	181	0	12	193
Total interest	3,799	7	167	3,973
Total expense	**17,628**	**16**	**1,078**	**18,722**
(Deficit)/surplus revenue	(258)	(1)	(146)	(405)
Investment:				
Federally financed power	5,357	13	125	5,495
Non-Federally financed power	202	0	0	202
Nonpower	2,379	1	4	2,384
Total investment	7,938	14	129	8,081
Investment repaid:				
Federally financed power	2,856	1	13	2,870
Non-Federally financed power	59	0	4	63
Nonpower	41	0	0	41
Total investment repaid	**2,956**	**1**	**17**	**2,974**
Investment unpaid:				
Federally financed power	2,501	13	111	2,625
Non-Federally financed power	143	0	(4)	139
Nonpower	2,338	1	4	2,343
Total investment unpaid	**4,982**	**14**	**111**	**5,107**
Fund balances:				
Colorado River Development	3	1	2	6
Working capital	2	0	0	2
Percent of investment repaid to date:				
Federal	53.31%			52.23%
Non-Federal	29.21%			31.19%
Nonpower	1.72%			1.72%

Note: Repayment status is based on audited data as of Sept. 30, 2005. Difference between the 2005 data in this table and the Combined Power System Statements of Revenues and Expenses in the Annual Report are footnoted in the individual power system Status of Repayment tables in Western's Statistical Appendix.

Management's Discussion and Analysis[1]

Outlook

Energy is central to the country's economic and national security, helping drive the global economy. Its availability has a significant impact on the quality of life and health of our nation's people and our environment. As part of the Federal Hydropower Program, Western—in conjunction with our generation partners fosters a diverse supply of reliable, affordable and environmentally-sound energy while increasing the nation's energy options.

Western's mission is to market and deliver electricity generated primarily from hydropower projects at Federally-owned dams operated by the U.S. Army Corps of Engineers, Department of Interior's Bureau of Reclamation and the State Department's International Boundary and Water Commission. In today's environment, these activities require we contend with an endless stream of industry developments and challenges—aging equipment, cost containment, overcrowded transmission line corridors and drought— further impacting our ability to maintain system reliability and provide a secure energy supply.

Hydro generation, by its nature, is a highly variable resource. Operationally, it is a byproduct of water releases, subordinate by law to the other purposes of multipurpose projects, namely: irrigation, navigation, flood control, environmental species protection and recreation. Western purchases power to fulfill our statutory obligations to meet the energy requirements of project use loads and long-term firm power sales contracts whenever Federal hydro generation is not sufficient. We also purchase power and ancillary services necessary to meet reliability requirements for the system control areas we maintain.

In FY 2005, Western sold 31.2 million MWh of energy, resulting in $713.7 million of revenues from power sales. However, the continuing drought required we purchase additional power from suppliers to meet our contract commitments. When combined with increasing wholesale energy prices, these efforts have led to extensive use of alternative customer financing and also emergency funding, driving rate increases for many Western power systems. In response, we made widespread changes to the marketing structure in a number of projects. Under both the Energy Planning and Management Program and project-specific marketing plans, Western adopted policies that emphasize customer choice and lessen the need to purchase power. Our internal purchase power procedures were also adjusted, allowing us to acquire firming energy over a longer future time period to avoid the price volatility associated with short-term markets. Western also aggressively pursued additional sources of revenue, such as facility use fees, ancillary services, additional transmission sales and new classes of service to mitigate the revenue requirement we would otherwise collect through our power and transmission rates.

Providing a diverse customer base with reliable transmission is central to Western's mission. Using an integrated 17,000 circuit-mile, high-voltage Federal transmission system, spanning a service area covering 1.3 million square miles in 15 states, we deliver reliable electric power to most of the western half of the United States. Since our inception in 1977, Western has added thousands of additional miles of lines to our system and managed hundreds of requests for interconnection. However, to guarantee reliable electric power, we continue to modernize the grid through transmission upgrades. Such endeavors fit well with the goals of the Energy

Policy Act of 2005 to accommodate restructuring changes in the electric utility industry, ensure transmission system adequacy and more stringent reliability standards. Ensuring that our customers can rely on the delivery of cost-based hydropower is our main focus as we explore ways to help solve transmission constraints, increase transmission system reliability and support renewable energy efforts. Hand-in-hand with the help of our energy partners, we will build a modern 21st century electric grid, remaining steadfast in our commitment to provide customers with reliable hydroelectric power.

Results of Operations

Fiscal year 2005 was drier than average throughout Western's service territory, including the Central Valley Project. Generation was down 12 percent from FY 2004 levels to 20,970 GWh, a 10-year low, as the drought continued to adversely impact power system operations. Despite the drought, our systems contributed $17.3 million toward repayment of investment. Specifically, we repaid $13.1 million of Federally-financed power investment, down from $93.6 million in FY 2004, and an additional $4.3 million of non-Federally financed power investment. The Boulder Canyon Project provided the majority of these funds, while adjusting entries in power repayment studies resulted in an additional $0.8 million available for repayment. Total repayment in FY 2005 was approximately $18.2 million.

Revenues

Operating revenues for FY 2005 were $951.1 million, up $41.3 million (5 percent) compared to FY 2004 due primarily to increases in other operating income, as offset by decreased sales of electric power.

Specifically, other operating income increased $84 million (54 percent) to $239.7 million in FY 2005 signaling a return to more normal operating levels in CVP and the Colorado River Storage Project. CVP income increased $111.1 million to $62.7 million, up from FY 2004 to accommodate final refunds to customers under the rate adjustment clause of the old marketing plan, whereas CRSP income decreased $25.6 million, to $27.8 million due to the recognition of deferred revenue identified in FY 2004.

Partially offsetting the increase in other operating income was a decrease in sales of electric power of $29.4 million (4 percent) to $713.7 million. Most notably, revenue decreased $33.1 million in CVP, reflecting changes in the basis for the revenue stream in the Post 04 Marketing Plan from cost per kWh to the power revenue requirement, and $17 million in CRSP to $127.7 million to accommodate a $14.5 million withdrawal from the Operating Energy Account for use by the Pick-Sloan Missouri Basin Program. Increases in PSMBP of nearly $10 million reflect decreases in nonfirm and Joint Marketing Program sales (agreements with Western customers to take advantage of economies of scale by jointly marketing and selling surplus power), as offset by revenue recognized from the energy banking arrangement with CRSP and transfer of $5 million as partial settlement for long-standing loss deviation with CRSP.

Decreased sales were offset in FY 2005 by changes to project marketing structures and corresponding rate increases in a number of power systems, as the composite firm power rate per kWh continued upward to $21.02 in FY 2005, from $17.68 in FY 2004 and $16.60 in FY 2003.

Expenses

Total operating expenses for FY 2005 were $1,034 million, up $141 million (16 percent) from $893 million in FY 2004. Specifically, purchase power costs increased in FY 2005 by $105.6 million (27 percent) to $490.6 million for drought-related purchases in PSMBP of $67.4 million and to reflect the movement to open market energy purchases signaling the end of the long-term power contract with Pacific Gas and Electric Company in CVP of $43.5 million.

Purchased transmission expense decreased by $8.1 million (15 percent) to $46.6 million in FY 2005, as energy imbalance revenue and augmentation expenses decreased by nearly $5.6 million in PSMBP, and power purchases decreased in CRSP ($2.2 million).

FY 2005 operations and maintenance expenses increased $21.9 million (7 percent) to $319.3 million to support new business processes in CVP under the Post 04 Marketing Plan and sub control area with the Sacramento Municipal Utility District ($8 million), and for increases in operation and maintenance expenses for Reclamation of $4.8 million, including generation overhauls on the New Melones Units 1 and 2. Administrative and general expenses remained relatively flat increasing only $1.4 million (3 percent) to $54.1 million, consistent with Western's cost objective of keeping increases in these expenses below the rate of inflation.

Capital Program

During FY 2005, Western and the generating agencies transferred $157.9 million from construction work-in-progress to completed plant, as compared with $96.4 million in FY 2004. New capital investments included sub and switching station equipment, fiber optic installation, expansion of communication systems and assorted replacements of transmission and generation assets to enhance or upgrade the grid. Completed plant of $137.3 million in PSMBP included various substation upgrades, transmission line improvements and microwave projects, with $8.2 million in CVP for substation upgrades.

During FY 2005, the Federal Hydropower Program initiated new construction and/or continued previous uncompleted construction projects totaling approximately $98.1 million, as compared to $99.8 million in FY 2004. Construction projects include upgrades to switchyards, substations, transmission lines and communication systems, with $58.5 million of activity in PSMBP, $13.7 million in the Parker-Davis Project and $11.6 million and $10.7 million in CVP and CRSP, respectively. ■

[1] Financial statement numbers, revenue, energy sales and generation described here include interproject and project use activities, but exclude Central Arizona Project transactions, thus isolating hydropower activities and operations only.

Performance Measurements

The Chief Financial Officers Act of 1990 requires Federal entities develop performance measures to assist managers and stakeholders in evaluating the efficiency of Federal programs. The requirement was further emphasized in the Government Performance and Results Act of 1993, and subsequently reinforced in the Presidents Management Agenda.

The financial performance measures outlined below support the organizational objectives and management responsibilities of Western and our generating partners (U.S. Army Corps of Engineers, Bureau of Reclamation, and International Boundary and Water Commission) and were selected from industry standard financial ratios used by public power systems for comparison in assessing electric utility performance. The operational measures outlined below were selected from industry reliability and Federal safety standards, to compare and assess the effectiveness of Western's operations.

Financial Performance Measures[1]

The investment repayment indicator measures cumulative investment (Federally and non-Federally financed power projects and irrigation assistance) repaid as a percentage of total investment at the end of each year. At the end of FY 2005, total investment increased by $142.8 million to approximately $8.1 billion, with about $18.2 million applied toward investment repayment. The FY 2005 investment repayment ratio of 36.86 percent decreased from the FY 2004 ratio of 37.23 percent.

During FY 2005, $13.1 million from current year operations (down from $93.6 million in FY 2004) was available to repay the Federally-financed power investment; however, the percentage of investment repaid to date decreased to an overall level of 52.23 percent from 53.31 percent in FY 2004. An additional $4.3 million of non-Federally financed power investment was applied, increasing the level repaid to 31.19 percent, up from 29.21 percent in FY 2004. Adjustments totaling $0.8 million were made as a result of power repayment study true-ups.

Western tracks several financial performance measures, which allow us to benchmark our efficiency against other power generating utilities. Utility industry statistics, the Selected Financial and Operating Ratios of Public Power Systems, 2004, dated April 2006, as prepared by the American Public Power Association, are used as industry comparables for the generation and sale of hydroelectric power. Statistics are calculated based on data from more than 200 of the largest consumer-owned electric utilities in the United States.

The operating ratio measures the proportion of revenues received from power sales, rate adjustments and other activities required to cover operating costs associated with producing and selling electricity. Costs include operations and maintenance, administrative and general expenses, purchased power and purchased transmission. Western's FY 2005 ratio increased to 99.56 percent from the FY 2004 ratio of 87.56 percent primarily due to a significant increase in power purchases ($105.6 million) to meet contract commitments under the prolonged drought. The most recent industry ratio was 81.60 percent.

The total power supply expense per kWh sold measures all power supply costs, including generation and purchased power, associated with the sale of each kWh of electricity. The FY 2005 rate of $0.0292/kWh was slightly higher than the FY 2004 rate of $0.0224/kWh primarily due to increases in PPW, coupled with a decrease in kWh sold. The most recent industry average was $0.052/kWh.

[1] Financial statement numbers presented here include interproject amounts for sales of $2.1 million, other operating income of $11 million, purchased power of $11.7 million, and purchased transmission services of $0.6 million. Additionally, the Central Arizona Project has been excluded, which reduced sales by $95 million, other operating income by $24.2 million and increased net income transfers of $118.9 million. Revenue and energy sales include interproject and project use.

Consolidated Financial Performance Indicators

(Dollars/Energy in thousands)

	2005[1]	2004[1]
Investment repaid		
Ratio	36.80%	37.23%
Paid investment	$2,973,296	$2,955,136
Total investment	**$8,080,340**	**$7,937,493**
Operating ratio		
Ratio	99.56%	87.56%
O&M, AGE, PP, PT	$910,614	$789,816
Total sales revenue	**$914,677**	**$902,040**
Total power supply expense per kWh sold		
Rate	$0.0292	$0.0224
O&M, AGE, PP, PT	$910,614	$789,816
kWh sold	**31,227,426**	**35,237,912**

[1] Financial statement numbers, revenue, energy sales and generation described here include interproject and project use activities, but exclude Central Arizona Project transactions, thus isolating hydropower activities and operations only.

Operational Performance Measures

Western is committed to a safe, efficient and reliable transmission system and reports on a number of operational measures for transmission system efficiency and occupational safety and health.

Uninterrupted delivery of power is a key focus for Western. With more than 17,000 miles of high-voltage transmission lines spanning most of the western half of the United States, Western markets more than 31.2 billion kWhs of Federal hydropower annually to more than 750 wholesale utility customers. The hydroelectric resource is an important component of our customer's energy mix, relied upon for residential, commercial, agricultural and municipal uses.

System reliability, i.e., transmission system performance, is measured using the instantaneous difference between loads and generation. Good control area performance ensures that the Federal system operates reliably, and to maintain equity among interconnected systems.

Performance for each of Western's control areas is measured using North American Electric Reliability Council's control area performance standards 1 and 2 (CPS1 and CPS2). A control area compliance rating of "Pass" is achieved when a power system receives, for each month of the fiscal year, a CPS1 performance level of 100 percent minimum and a CPS2 performance level of 90 percent minimum. Western's performance for FY 2005 was 183.89 percent for CPS1 and 98.17 percent for CPS2. The FY 2005 industry averages were 161.38 percent for CPS1 and 95.91 percent for CPS2, as compared to 165.11 and 96.66 in FY 2004. Western's FY 2005 performance is consistent with FY 2004 and 2003, respectively (CPS1 – 184.01 percent and CPS2 – 98.30 percent/CPS1 – 185.61

percent and CPS2 – 98.09 percent) and reflects the increasing complexity of system operations both at Western and in industry.

Accountable transmission system outages quantify the efficiency of Western's efforts to reduce or eliminate avoidable outages (those caused by human error through improper or incorrect equipment operation, installation or maintenance). For FY 2005, Western recorded 23 such outages, achieving our stated goal for the year of not exceeding the average number of outages for the past five years (23).

Although some emergency work is weather-related and beyond Western's control, unanticipated repair work related to equipment failure should be minimized by keeping equipment in good operating condition. For FY 2005, Western's ratio of unanticipated repair work hours to total maintenance hours was 7.1 percent, well below the targeted goal of 16 percent or less.

Safety: Western is committed to maintaining a safe, accident-free work place. This commitment is demonstrated by Western's Safety and Health Program, dedicated to increasing awareness of safe work practices.

Occupational safety and health performance measures, as adopted by the Department of Energy for occupational injuries, are recognized throughout the electric utility industry (public and private utilities) and by information-gathering entities which include the National Safety Council, the U.S. Department of Labor Bureau of Labor Statistics and the National Institute for Occupational Safety and Health. Industry statistics are provided on a calendar year basis. Accordingly, Western's measures have been calculated for the same time period. The latest statistics currently available (calendar year 2004) are provided by the U.S. Department of Labor, Bureau of Labor Statistics.

Total Recordable Accident Frequency Rate is calculated by multiplying the number of recordable injury cases by 200,000 hours (common base of 100 full-time workers), then dividing the product by the total hours worked. Recordable accidents include injuries or illnesses that result in any of the following: death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, loss of consciousness, or significant injuries or illnesses diagnosed by a physician or other licensed health care professional. Western's CY 2005 rate of 1.7 was well below Western's target objective of equal to or less than 3.3. This decrease represents an ongoing emphasis by Western to employee awareness of hazard recognition and the avoidance of hazardous working conditions. The CY 2004 standard industry rate was 6.2.

Independent Auditor's Report

The Administrator
Western Area Power Administration,
United States Department of Energy:

We have audited the accompanying combined power system balance sheets of the Western Area Power Administration (Western), an agency of the U.S. Department of Energy, and the Western affiliated power generating functions of the U.S. Department of the Interior, Bureau of Reclamation; the U.S. Department of Defense, Army Corps of Engineers; and U.S. Department of State, International Boundary and Water Commission (collectively, the generating agencies), as of September 30, 2005 and 2004, and the related combined power system statements of revenues and expenses, and accumulated net deficit, and cash flows for the years then ended. These combined power system financial statements are the responsibility of Western and the generating agencies' management. Our responsibility is to express an opinion on these combined power system financial statements based on our audits. We did not audit the financial statements of the affiliated power generation function of the U.S. Department of the Interior, Bureau of Reclamation (Reclamation), which statements reflect total assets constituting 31% and 31%, respectively, of combined total assets as of September 30, 2005 and 2004 and total revenues constituting 24% and 25%, respectively, of combined total revenues for the years then ended. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Reclamation, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America; the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States; and Office of Management and Budget (OMB) Bulletin No. 01-02, Audit Requirements for Federal Financial Statements. Those standards and OMB Bulletin No. 01-02 require that we plan and perform the audit to obtain reasonable assurance about whether the respective financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Western and the generating agencies' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the respective financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the combined power system financial statements referred to above present fairly, in all material respects, the combined financial position of Western and its affiliated power generating agencies, as of September 30, 2005 and 2004, and their combined operations, changes in accumulated net deficit, and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, we have also issued our report dated July 17, 2006, on our consideration of Western and the generating agencies' internal control over financial reporting and our tests of its compliance with certain provisions of laws and regulations. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be read in conjunction with this report in considering the results of our audits.

Deloitte & Touche LLP

Denver, Colorado
July 17, 2006

Combined Power System Balance Sheets

As of September 30, 2005 and 2004 (in thousands)

	2005	2004
Assets		
Utility plant:		
Completed plant	$ 5,742,384	$ 5,608,553
Accumulated depreciation	(2,581,370)	(2,484,856)
Net completed plant	3,161,014	3,123,697
Construction work-in-progress	158,517	202,764
Net utility plant	3,319,531	3,326,461
Cash	425,795	538,013
Accounts receivable, net	116,696	138,625
Other assets	195,190	153,814
Total assets	**$ 4,057,212**	**$ 4,156,913**
Federal investment & liabilities		
Federal investment:		
Congressional appropriations	$ 11,607,495	$ 11,126,870
Interest on Federal investment	4,461,428	4,296,515
Transfer of property & services, net	510,498	638,729
Gross Federal investment	16,579,421	16,062,114
Funds returned to U.S. Treasury	(12,509,631)	(12,146,661)
Net outstanding Federal investment	4,069,790	3,915,453
Accumulated net deficit	(517,709)	(267,825)
Total Federal investment	**$ 3,552,081**	**$ 3,647,628**
Commitments and contingencies (notes 1,6,7 and 8)		
Liabilities:		
Accounts payable	70,474	127,280
Other liabilities	434,657	382,005
Total liabilities	**505,131**	**509,285**
Total Federal investment & liabilities	**$ 4,057,212**	**$ 4,156,913**

See accompanying notes to combined power system financial statements.

Combined Power System Statements of Revenues and Expenses, and Accumulated Net Deficit

For the Years Ended September 30, 2005 and 2004 (in thousands)

	2005	2004
Operating revenues:		
Sales of electric power	$ 806,576	$ 818,115
Other operating income	252,871	174,235
Gross operating revenues	1,059,447	992,350
Income transfers, net	(121,492)	(99,516)
Total operating revenues	**937,955**	**892,834**
Operating expenses:		
Operation and maintenance	318,206	297,641
Administration and general	54,404	52,742
Purchased power	478,951	373,083
Purchased transmission services	45,930	49,407
Depreciation	123,428	103,199
Total operating expenses	**1,020,919**	**876,072**
Net operating revenues (deficit)	**(82,964)**	**16,762**
Interest expenses:		
Interest on Federal investment	249,682	168,935
Interest on non-federally financed funding	4,927	8,326
Allowance for funds used during construction	(87,689)	(9,705)
Net interest expenses	**166,920**	**167,556**
Net deficit	**(249,884)**	**(150,794)**
Accumulated net deficit: Balance, beginning of year	**(267,825)**	**(117,189)**
Irrigation assistance	**0**	**158**
Accumulated net deficit, end of year	**$ (517,709)**	**$ (267,825)**

See accompanying notes to combined power system financial statements.

Combined Power System Statements of Cash Flows

For the Years Ended September 30, 2005 and 2004 (in thousands)

	2005	2004
Cash flows from operating activities:		
Net deficit	$ (249,884)	$ (150,794)
Adjustments to reconcile net deficit to net cash provided by operating activities:		
Depreciation	123,428	103,199
Interest on Federal investment	152,967	157,244
Income Transfers	113	0
Gain/Loss on disposition of assets	3,055	2,808
(Increase) decrease in assets:		
Accounts receivable	21,929	69,508
Other assets	(44,046)	2,002
Increase (decrease) in liabilities:		
Accounts payable	(56,806)	20,910
Other liabilities	33,552	(84,177)
Net cash provided by operating activities:	**(15,692)**	**120,700**
Cash flows from investing activities:		
Investment in utility plant	**(98,136)**	**(99,763)**
Cash flows from financing activities:		
Congressional appropriations, net	344,005	431,917
Funds returned to U.S. Treasury	(361,495)	(451,425)
Principal payments on non-federally financed funding	19,100	24,096
Irrigation assistance	0	158
Net cash used in financing activities	**1,610**	**4,746**
Net Increase in cash	**(112,218)**	**25,683**
Cash, beginning of year	**538,013**	**512,330**
Cash, end of year	**$ 425,795**	**$ 538,013**
Supplemental schedule of noncash investing and financing activities		
Transfer of construction work-in-progress to completed plant	$ 157,927	$ 96,367
Capitalized interest during construction	$ 12,019	$ 9,705

See accompanying notes to combined power system financial statements.

Notes to Combined Power System Financial Statements

As of and for the years ended September 30, 2005 and 2004

(1) Basis of Presentation and Summary of Significant Accounting Policies

(a) Principles of Combination

The combined power system financial statements include the financial position, results of operations and cash flows of the Western Area Power Administration (Western), an agency of the U.S. Department of Energy (DOE), and the power generating function of the U.S. Department of the Interior, Bureau of Reclamation (Reclamation); the U.S. Department of Defense, Army Corps of Engineers (Corps); and the U.S. Department of State, International Boundary and Water Commission (IBWC) (collectively known as the generating agencies) for the individual power systems. The jointly owned power systems are separately managed and financed, and maintain separate accounting records. Western, a Federal power marketing administration, markets and transmits hydroelectric power generated from these power systems operated and maintained by the generating agencies throughout 15 western states. The power systems, with the exception of the Central Arizona Project (CAP) and the Pacific Northwest-Pacific Southwest Intertie (Intertie), are part of multipurpose water resource projects and include certain Western transmission facilities and certain generating agency facilities.

Operating expenses and net assets of multipurpose water resource projects are allocated among project activities, which are primarily; power, irrigation, recreation, municipal and industrial water, navigation and flood control (see Note 4). The combined power system financial statements include only those expenses and net assets which are expected to be recovered through the sale of power and other related income.

Although Reclamation holds an entitlement to power from the Navajo Generating Station and capacity from the CAP transmission facilities, the Federal government has no ownership in these facilities. As such, neither the CAP assets nor the associated entitlements are included in the combined power system financial statements.

Accounts are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP) and the Federal Energy Regulatory Commission's (FERC) prescribed uniform system of accounts for electric utilities. Accounting policies also reflect specific legislation and executive directives issued by departments of the Federal government. The combined power system financial statements are presented in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effect of Certain Types of Regulation*. The provisions of SFAS No. 71 require, among other things, that regulated enterprises reflect the regulator's rate actions in their financial statements, when appropriate. These rate actions can provide reasonable assurance of the existence of an asset, reduce or eliminate the value of an asset, or impose a liability on a regulated enterprise.

For purposes of financial reporting, the facilities and related operations of Western and the generating agencies are considered one entity. All intraentity balances and transactions have been eliminated from the combined power system financial statements.

The facilities and net revenues included in these combined power system financial statements are exempt from taxation.

(b) Confirmation and Approval of Rates

The Secretary of Energy (Secretary) has delegated authority to Western's Administrator to develop power rates for the power systems. The Deputy Secretary of Energy has the authority to confirm, approve and place such rates in effect on an interim basis. The Secretary delegated to FERC the authority to confirm, approve and place such rates in effect on a final basis, to remand, or to disapprove such rates. Refunds with interest, as determined by the FERC, are authorized if rates finally approved are lower than rates approved on an interim basis. However, if at any time FERC determines that the administrative cost of a refund would exceed the amount to be refunded, no refunds will be required. No refunds are anticipated in connection with rates approved on an interim basis through September 30, 2005.

(c) Operating Revenues

Operating revenues are recognized when goods or services are provided to the public or another government agency. Except for power systems using revolving funds, cash received from sales is deposited directly with the U.S. Department of the Treasury (U.S. Treasury) and is reflected as Funds Returned to U.S. Treasury in the Combined Power System Balance Sheet. As such, these funds are unavailable for power system operating needs. For power systems using revolving funds, cash received is deposited in the U.S. Treasury and remains available to the power system. Cash collected into revolving funds in excess of operating requirements is used for repayment of Federal investment and interest.

Power and transmission rates are established under requirements of the power systems' authorizing legislation and related Federal statutes and are intended to provide sufficient revenue to recover all costs allocated to power and, in some power systems, a portion of irrigation-related costs (see Note 7). Costs allocated to power include repayment of Federal investment in power facilities and associated interest. Rates are structured to provide for repayment of Federal investment in power facilities, generally over 50 years, while operating expenses and interest on Federal investment are recovered annually. Replacements of utility plant are generally to be repaid over their expected service lives.

The power systems' legislation does not recognize annual depreciation based on actual service lives as a measure of the required repayment for investment in utility plant. This results in some assets being fully depreciated before costs are recovered; whereas, annual depreciation costs on other assets may continue after such costs have been recovered through revenues. Over the life of the combined power systems, accumulated net revenues represent timing differences between the recognition of expenses and related revenues. Because Western and the generating agencies are nonprofit Federal agencies, accumulated net revenues, to the extent that they are available, are committed to Federal investment repayment.

Other operating income represents the amount of funds collected from sources other than the sale of electric power. These revenues include rental of electric property, power wheeling and transmission services.

Net income transfers represent the amount of funds collected but subsequently transferred to Reclamation. This amount is primarily the surplus generation billed from the Navajo Generating Station by Western, on behalf of Reclamation's CAP.

For the Central Valley Power System (CVP), the net revenue forecasted in the rate case is compared to the actual net revenue by December 31 for the previous fiscal year. If the actual net revenue is less than the projected net revenue, a surcharge may be assessed. If the actual net revenue is greater than the projected net revenue, a credit may be granted. The surcharge or credit is then applied to CVP firm power customers' bills from January through September.

(d) Cash

For purposes of the Combined Power System Financial Statements, cash consists principally of the undisbursed balance of funds authorized by Congress, customer advances and revolving fund balances at the U.S. Treasury.

(e) Accounts Receivable, Net

The estimate of the allowances is based on past experience in the collection of receivables and an analysis of the outstanding balances. The amounts due for receivables are stated net of an allowance of $0.1 million and $1.5 million for uncollectible accounts as of September 30, 2005 and 2004, respectively, from a gross amount of $116.8 million and $140.1 million respectively.

Billing methods used by Western include net billing and bill crediting. Net billing is a two-way agreement between Western and a customer, whereby both buy and sell power to each other. Monthly sales and purchases, including any customer advances received, are netted between the two parties and the customer is provided either an invoice or a credit. Bill crediting involves a three-way net billing arrangement among Western, a customer and a third party. For example, Western purchases power from a third-party supplier, delivers it to the customer; the customer then pays the third-party supplier and receives a credit on its bill from Western.

(f) Stores Inventory

Inventory consists of hardware, tools, and maintenance parts and supplies. Inventory is valued using the average cost method.

(g) Utility Plant

Utility plant is stated at original cost, net of contributions in aid of construction by entities outside of the combined power system. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision and administrative and general expense; and interest during construction. The costs of additions, major replacements and betterments are capitalized; whereas, repairs are charged to operation and maintenance expense.

The cost of retired utility plant, net of accumulated depreciation, is charged to operation and maintenance expense as a gain (loss) and the net of removal costs and salvage credits is capitalized as part of the direct replacement asset. If there is not a replacement asset, the net of removal costs and salvage credits is charged to operation and maintenance expense. Plant assets of the combined power system are currently depreciated using the straight-line method over estimated service lives ranging from 8 to 50 years for transmission assets and 13 to 100 years for generation assets. Power rights are amortized over 40 years.

(h) Interest on Federal Investment

Interest is accrued annually on the Federal investment based on the Federal statute and power system legislation. Such interest is reflected as an expense in the Combined Power System Statement of Revenues and Expenses. Western calculates interest annually based on the unpaid Federal investment owed to the U.S. Treasury using rates set by law, administrative orders pursuant to law or administrative policies.

All power systems recognize an annual interest credit for payments of interest on obligations that are due annually to the U.S. Treasury. Interest rates on unpaid Federal investments ranged from 2.5 to 12.4 percent for the years ended September 30, 2005 and 2004.

As provided by Federal law, interest is not assessed on Federal investment in irrigation facilities anticipated to be repaid through power sales (see Note 7).

(i) Allowance for Funds Used During Construction

Interest During Construction (IDC or Allowance for Funds Used During Construction) represents interest on funds borrowed from the U.S. Treasury during the construction of all generating and transmission facilities. Western calculates IDC based on the average annual outstanding balance of construction work-in-progress. Western and the generating agencies' policy is to capitalize IDC through the end of the fiscal year in which assets are placed in service. IDC is recovered over the repayment period of the related plant asset. Applicable interest rates ranged from 4.9 to 8.9 percent for the years ended September 30, 2005 and 2004, depending on the year in which construction on the transmission and generation facilities was initiated or the authorizing legislation.

(j) Pension and Other Retirement Benefits

Statement of Federal Financial Accounting Standards (SFFAS) No. 4, *Managerial Cost Accounting Concepts and Standards for the Federal Government,* and SFFAS No. 5, *Accounting for Liabilities of the Federal Government,* direct the full cost reporting of employment benefits by employing entity. These statements require Federal agencies to record the government's cost of providing pension, life and health insurance and other post-employment benefits (severance payment, counseling and training, workers' compensation benefits, etc.) regardless of the funding agency.

(k) Use of Estimates

Management of Western and the generating agencies have made many estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these combined power system financial statements in conformity with GAAP. Actual results could differ significantly from those estimates.

(l) Derivative and Hedging Activities

Western analyzes derivative financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* This statement requires that all derivative instruments, as defined by SFAS No. 133, be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the statement of operations, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship at the inception of the contract to apply hedge accounting.

Western enters into contracts for the purchase and sale of electricity for use in their business operations. SFAS No. 133 requires Western to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented and exempted from the accounting and reporting requirements of SFAS No. 133.

Western's policy is to fulfill all derivative and hedging contracts by either providing power to a third party or by taking delivery of power from a third party as provided for in each contract. Western's policy does not authorize the use of derivative or hedging instruments for speculative purposes such as hedging electricity pricing fluctuations beyond Western's estimated capacity to deliver or receive power. Accordingly, Western evaluates all of its contracts to determine if they are derivatives and, if applicable, to ensure that they qualify and meet the normal purchases and normal sales designation requirements under SFAS No. 133. Normal purchases and normal sales contracts are accounted for as executory contracts as required under generally accepted accounting principles.

(m) Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject Western and the generating agencies to credit risk, include accounts receivable for customer purchases of power, transmission, or other products and services. These receivables are primarily with a group of diverse customers that are generally large, stable and established organizations which do not represent a significant credit risk. Although Western and the generating agencies are affected by the well-being of the utility industry, management does not believe a significant risk of loss from a concentration of credit exists.

Credit Risk from California

Pacific Gas and Electric Company (PG&E) emerged from the Chapter 11 bankruptcy reorganization on April 12, 2004, with its financial standing restored. PG&E is now in a position to pay off all valid credit claims in full. Pending settlement of a prior claim by Western for providing scheduling coordinator services on behalf of a preference power customer, the California Independent System Operator (CAISO) has an outstanding balance of approximately $1.4 million. The Department of Energy's Oakland Operations Office and Lassen Municipal Utility District have an ongoing billing dispute with PG&E concerning power deliveries made under Contract 14-06-200-2948A (expired on December 31, 2004) through the CAISO. Although the value at risk is approximately $2 million, since Western performs only a billing function to these two entities, and is not financially liable, no credit risk accrues.

The California Power Exchange (Cal-PX) filed for Chapter 11 bankruptcy protection on March 9, 2001. Bankruptcy proceedings are still in progress. Cal-PX representatives continue to be engaged in the process of winding up its business affairs in an orderly and timely manner.

Western estimates that pending resolution of the Cal-PX bankruptcy case, the Cal-PX has an outstanding balance of approximately $4.1 million, as of September 30, 2005.

(n) Moveable Equipment

Moveable equipment represents the acquisition cost of capitalized movable equipment having a unit cost of $15,000 or more and an estimated useful life of two years or more. Examples of capitalized moveable equipment include computers, copiers, cranes, energy testing equipment, helicopters, trucks and wood chippers.

Western's internal use software is capitalized when the software has a service life of 3 years or more and a cost of $150,000 or more upon the completion of the software development phase or upon purchase of commercial off-the-shelf software applications. Reclamation's internal use software is subject to a $100,000 capitalization threshold with a service life from 2 to 5 years. No other Generating Agency has any capitalized internal use software.

(o) Abandoned Projects

In accordance with FERC regulations, Western's policy is to move capitalized costs into plant-in-service at the time the asset is placed in service. Occasionally, congressionally authorized projects originally planned for service are discontinued due to political and/or economic reasons. Western's policy is to classify these discontinued projects based on congressional action as abandoned projects and amortize them into the power rates over a reasonable period.

(p) Interchange Energy

Western's power contracts may include a provision for energy transfers between Western and a supplier that result in deferred energy debits or credits. Deferred energy debits or credits represent the valuation of excess energy delivered or received under the interchange energy contract provisions. The interchange balance is posted either as a deferred debit (other asset) when Western is the net supplier, or as a deferred credit (other liabilities) when Western is the net user.

(q) Recovery Implementation Program (RIP)

Section 8 of the Colorado River Storage Project Act of 1956, as amended, mandates that the Department of the Interior establish and implement programs to conserve fish and wildlife. Under this act and other legislation, Reclamation established programs to preserve the habitat and otherwise aid endangered fish and wildlife. The RIP is one such program and is managed by the U.S. Fish and Wildlife Service.

On October 30, 2000, Congress passed Public Law 106-392 that authorized additional funding to Reclamation to continue the RIP. The legislation specifies that a total of $17.0 million is to be collected by Western from its power customers and provided to Reclamation to finance capital costs and up to $6.0 million a year starting in FY 2001 for operating expenses, adjusted annually for inflation thereafter. Furthermore, the legislation states that operating expenses are considered non-reimbursable to the U.S. Treasury and a repayment of the Federal investment. Conversely, capital funded costs must be repaid to the U.S. Treasury through future power sales. Operating expenses were $1.6 million and $5.8 million for the years ended September 30, 2005 and 2004 respectively. Reimbursable capital costs for the years ended September 30, 2005 and 2004, respectively, were $3.2 million and $0.0 million.

(r) Unused Annual Leave

Unused annual leave represents accrued benefits which would be payable to employees upon retirement or separation from employment with the government. The amount not funded by revolving funds has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71.

(s) Transmission Termination Settlement

Western renegotiated certain CRSP long-term contractual obligations with third-party power providers. Under the terms of the settlement agreements, annual payments of $0.6 million will be made through 2007 to PacifiCorp. The recognition of the expense associated with the settlements has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71 (see Note 2).

(t) Customer Advances

Customer advances represent the current balance of advance payments received from power and other customers under co-sponsoring agreements with entities for construction, operation and maintenance, or other furnished items. Subsidiary accounts are maintained by customer to reflect the status of each advance. Also included are revenue financing contracts that provide for customer funds to be advanced for construction, maintenance or purchase power expenses. For these contracts, the customer is provided revenue credits on future power bills up to the amount of the advanced funds and, if applicable, any interest or fees.

(u) Workers' Compensation

Workers' compensation consists of two elements: a liability for expenses from actual claims incurred and paid by the Department of Labor (DOL) that Western and the generating agencies must reimburse; and an actuarial liability associated with cases incurred for which additional future claims may be made. In conjunction with SFFAS Nos. 4 and 5, DOL determined the actuarial liability associated with future claims using historical benefit payment patterns discounted to present value (37 years) using economic assumptions for 10-year U.S. Treasury notes and bonds.

The recovery of future claims is deferred for rate-making purposes until such time the claims are submitted to and paid by the DOL. Therefore, the recognition of the expense associated with the actuarially determined liability has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71 (see Note 2) to reflect the effects of the rate-making process.

(v) Capital Credits

Capital credits represent the investment made in non-profit organizations that result in equity ownership (patronage credits) that will result in a cash collection refund at a later date, which sometimes can be as long as 30 years. These credits are reported as income and deferred asset at the time of notification until the actual cash collection is made.

(2) Other Assets

Other assets as of September 30, 2005 and 2004 consist of the following (in thousands):

	2005	2004
Workers' compensation actuarial (see Note 1(u))	$60,507	$47,507
Moveable equipment, net (see Note 1(n))	37,256	37,335
Internal use software, net (see Note 1(n))	14,824	5,911
Accrued annual leave (see Note 1(r))	13,601	7,675
Interchange energy (see Note 1(p))	13,595	4,872
Abandoned project costs, net (see Note 1(o))	13,438	19,067
Stores inventory (see Note 1(f))	12,885	13,071
Recovery Implementation Program (see Note 1(q))	12,252	5,500
Deposit funds available	10,844	2,938
Energy banking deferral	1,965	1,915
Transmission termination settlement (see Note 1 (s))	1,000	1,600
Capital credits (see Note 1(v))	970	5,572
Other	2,053	851
Total	**$195,190**	**$153,814**

Abandoned project costs, net include the Celilo-Mead transmission line of $13.4 million and $14.2 million as of September 30, 2005 and 2004, respectively, which is being amortized over 23 years, through 2019.

The energy banking deferral is an arrangement between Western and a customer whereby excess power and/or transmission capacity is banked with the customer until power is needed to meet contractual obligations. Banked power and/or transmission capacity is recorded at a contractually agreed-upon price. The net revenue associated with the banking activity is deferred and recorded as an other liability.

(3) Utility Plant

Net Utility Plant as of September 30, 2005 consists of buildings, facilities, land and intangible power rights. Land costs for Western were $73.7 million and $73.5 million as of September 30, 2005 and 2004, respectively. Land costs for the generating agencies were $92.1 million and $93.2 million as of September 30, 2005 and 2004, respectively. Completed plant includes $110.0 million and $114.0 million of power rights, net of amortization of $53.0 million and $48.9 million as of September 30, 2005 and 2004, respectively.

(4) Federal Investment and Cost Allocation

(a) General

Federal investment consists of congressional appropriations, accumulated interest on unpaid Federal investment and the net transfers of property and services from other Federal agencies. Congressional appropriations is comprised of the cumulative appropriations received, net of expenses legislatively deemed nonreimbursable, and post-retirement benefits (see Note 8). Cumulative appropriations received, net of nonreimbursable expenses, totaled $11.6 billion and $11.1 billion as of September 30, 2005 and 2004, respectively. Postretirement benefits for the same time period totaled $106.8 million and $88.4 million, respectively. All power systems, except Dolores, Seedskadee, Boulder Canyon (BC) and the operations and maintenance and purchased power programs of the CRSP, are primarily financed through congressional appropriations for operation and maintenance, construction and rehabilitation and purchased power expenditures. A portion of construction and rehabilitation and purchased power expenditures are financed through other methods, such as advances from non-Federal entities; reimbursements from other Federal agencies; use of receipts authorization; and alternative methods such as net billing and bill crediting; or any combination of these methods.

Operating expenses (excluding depreciation expense) and interest on the unpaid Federal investment should be repaid annually. In cases where funds are not available for repayment, such unpaid annual net deficits become payable from the future years' revenues. Interest is accrued on cumulative annual net deficits until paid. Deficits for operating expenses begin to accrue interest in the year they occur, while interest expense deficits begin to accrue interest in the following year they occur. As of September 30, 2005 and 2004, certain power systems have incurred operating and interest expense deficits aggregating approximately $405.0 million and $258.5 million, respectively. In cases where funds are available, unless otherwise required by legislation, repayment of Federal investment is applied to the increment bearing the highest interest rate.

(b) Federal Investment in Multipurpose Facilities

The Federal investment in certain multipurpose facilities, primarily dams and structures integral to power generation, required to be repaid from the power sales, has been determined from preliminary cost allocation studies based on project evaluation standards approved by Congress. Allocations between power and non-power activities may be changed in future years; however, the project evaluation standards cannot be changed unless approved by Congress.

Final studies will be performed by Reclamation and the Corps, as appropriate, upon completion of each individual power project and are still pending for all but the Fryingpan-Arkansas Power System (FryArk). Reclamation completed the final FryArk study in 1993. The BCP and Parker-Davis power systems are not subject to cost allocation studies since the power systems' enacting legislation require the total costs of the dams and appurtenant structures be repaid through power revenues.

With final cost allocation studies still pending for many of the individual power systems, the potential exists for significant future adjustment in the Federal investment for the cost of multi-purpose facilities allocated to power and the related accrued interest on the unpaid Federal investment. Such reallocations could affect the individual power system rates. For example, in 1997, Reclamation studied the implications of a cost reallocation of the Pick-Sloan Missouri Basin Program (P-SMBP) on existing water and power rates. The study resulted in additional costs, ranging from $0 to $416 million (depending on the assumptions of the cost methodologies used), which may be reallocated to power facilities.

(5) Other Liabilities

Other liabilities as of September 30, 2005 and 2004 consist of the following (in thousands):

	2005	2004
Long-term construction financing	$158,869	$164,542
Customer advances	124,551	110,783
Workers' compensation actuarial (see Note 1(u))	60,507	47,507
Interchange energy (see Note 1(p))	13,595	4,872
Custodial liability	13,347	12,279
Accrued annual leave (see Note 1(r))	13,191	12,378
Recovery Implementation Program (see Note 1(q))	12,252	5,500
Deposit funds available	8,876	2,965
Accrued payroll benefits	8,578	7,170
Workers' compensation accrual (see Note 1(u))	8,025	8,940
Litigation accrual	5,900	0
Energy banking deferral	1,965	1,915
Transmission termination settlement (see Note 1(s))	1,000	1,600
Other	4,001	1,554
Total	**$434,657**	**$382,005**

The majority of long-term construction financing consists of three significant contractual arrangements. The first significant arrangement provides customer financing for the Boulder Canyon power system to upgrade each of the generating units at Hoover Dam. The obligation to these customers is scheduled to be satisfied through issuing credits on power bills over a period through FY 2017, at interest rates ranging between 5.5 and 8.2 percent. As of September 30, 2005 and 2004, the outstanding obligation was $114.1 million and $118.1 million, respectively.

The second significant arrangement consists of the principal payable to the State of Wyoming for providing partial financing for improvements at Buffalo Bill Dam (P-SMBP Power System) and associated power plants. This liability is being repaid over a period of 35 years, which began in 1996, at an approximate interest rate of 11.1 percent. The outstanding obligation amounted to $20.9 million and $21.0 million as of September 30, 2005 and 2004, respectively.

The third significant arrangement is principal due to a customer for providing financing for the construction of the Griffith-McConnico and Griffith-Peacock transmission lines along with certain assets at Peacock Substation, and McConnico Switching Station. Repayment is through power bill credits that began in 2001 and end in 2018. The interest rate is 8.5 percent. As of September 30, 2005 and 2004, the outstanding obligation totaled $23.5 million and $24.4 million, respectively.

Outstanding long-term construction financing as of September 30, 2005 is scheduled to be credited or repaid as follows (in thousands):

2006	$5,649
2007	6,668
2008	9,932
2009	10,659
2010	11,473
Thereafter	114,488
Total	**$158,869**

Custodial liabilities represent the amount of accrued revenue for the Central Arizona and Boulder Canyon power systems. The custodial revenue is transferred upon actual receipt of funds.

Western and the generating agencies included $60.5 million and $47.5 million as an actuarial liability for future workers' compensation claims in the Combined Power System Balance Sheet as of September 30, 2005 and 2004, respectively.

Cumulative unpaid expenses associated with actual claims incurred for Western and the generating agencies were $8.0 million and $8.9 million as of September 30, 2005 and 2004, respectively.

Western received a loan from the State of Colorado for $5.5 million in December 2002 (FY 2003) at an interest rate of 4.5 percent per year. Another $5.9 million was received in December 2004 (FY 2005) with an interest rate of 3.25 percent. These loans funded Reclamation's endangered fish recovery implementation programs (see note 1(q)). Interest began accruing at the time loans were granted, and is being capitalized. These balances, with capitalized interest and fees, total $12.3 million as of September 30, 2005. The original principal balances and the associated capitalized interest will begin to be repaid through power revenues beginning in 2012.

(6) Lease Commitments

Western and the generating agencies have several cancelable operating leases, primarily for general purpose motor vehicles and office and warehouse space that expire over the next 14 years.

Western has a non-cancelable lease that expires in 2009 for Western's Corporate Service Office. This lease represents an annual expense of approximately $2.0 million. The General Services Administration is the leaseholder for all locations with the exception of the Electric Power Training Center where Western is the leaseholder. The right to relinquish space on cancelable leases is available with 120-day notice to terminate.

These leases generally contain renewal options for periods ranging from three to five years and require the lessee to pay all executory costs such as maintenance and insurance. Rental expense for operating leases was approximately $9.5 million and $8.5 million for the years ended September 30, 2005 and 2004, respectively.

(7) Commitments and Contingencies

(a) General

Western and the generating agencies are involved in various claims, suits and complaints routine to the nature of their business. These Federal government organizations are self-insured for claims pertaining to litigation, unemployment, long-term disability and health and life insurance. Liabilities for these claims, as reported in the combined power system financial statements, are based on reported pending claims, estimates of claims incurred but not yet reported, actuarial reports and historical analysis. It is management's opinion that the ultimate disposition of these claims will not have a material adverse effect on the combined power system financial statements.

(b) Irrigation Assistance

Federal statute requires that certain individual power systems repay the U.S. Treasury that portion of Reclamation's project capital costs allocated to irrigation purposes determined by the Secretary of the Interior to be beyond the ability of the irrigation customers to repay. Although these repayments may be recovered through power sales, they do not represent an operating cost of the individual power systems and are treated as distributions from accumulated net revenues at the time of repayment.

Power repayment studies indicate that approximately $2.3 billion of existing non-power Federal investment will be repaid from future power revenues over a period not to exceed 60 years. Reclamation made irrigation assistance payments of $0.0 and $0.2 million for the years ended September 30, 2005 and 2004, respectively.

(c) Boulder Canyon Power System Improvements

In 1987, Reclamation initiated a project designed to increase (uprate) the generating capacity of the BC power system. Certain BC customers agreed to provide funding for these improvements, primarily through issuing long-term bonds. In some cases, proceeds from the bonds exceeded the amount required to fund the improvements.

For purposes of measuring the liability related to the Uprating Program (the Program), the total amount of the advances received from customers is reported in the Combined Power System Balance Sheet (see Note 5). Bond issuance costs are included in determining interest expense and are recognized over the term of debt repayment. Net proceeds from issuing the debt, in excess of the amount advanced to Reclamation, have similarly been excluded from the assets of the power system. Interest expense on the liability is measured based on the total outstanding bonded indebtedness. Interest income from excess proceeds reduces interest costs subject to arbitrage regulations. Until any remaining excess funds are applied against outstanding debt, the total interest cost of financing the Program will be subject to uncertainty.

(d) Colorado River Storage Project

In October 1992, Congress passed the Grand Canyon Protection Act of 1992 (the Act) to "protect . . . and improve the values for which the Grand Canyon National Park and Glen Canyon National Recreation Area were established."

The Act relieves CRSP power customers of repayment obligations for costs equivalent to certain expenses of environmental impact studies, associated purchased power, and other miscellaneous expenses related to Glen Canyon Dam. For the fiscal years ended September 30, 2005 and 2004, Western and Reclamation combined incurred $25.0 million and $11.5 million, respectively, in environmental costs which were deemed nonreimbursable. Accordingly, such costs have been recognized as a reduction of congressional appropriations in the Combined Power System Balance Sheet.

(e) Power Contract Commitments

Western has entered into various agreements for power and transmission purchases that vary in length but generally do not exceed 20 years. Western's long-term commitments for these power and transmission contracts, subject to the availability of Federal funds and contingent upon annual appropriations from Congress, are as follows (in thousands):

Year ending September 30:	Purchased power	Purchased transmission	Total
2006	$21,126	$5,807	$26,933
2007	21,083	5,691	26,774
2008	15,641	5,166	20,807
2009	10,365	5,004	15,369
2010	2,605	3,732	6,337
Thereafter	0	26,238	26,238
Total	$70,820	$51,638	$122,458

In addition to these contracts, Western maintains other long-term contracts which provide the ability to purchase unspecified quantities of transmission services within a contractually determined range and rate. To fulfill its contractual obligations to deliver power, Western has historically had to purchase a certain level of transmission services under these agreements. Western intends and anticipates it will be necessary to acquire resources under these contracts up to a maximum of $71.7 million through the life of the current contracts.

(f) Pacific Gas & Electric Company Settlement

Under the terms of the integration contract between PG&E and Western, Western pays PG&E an estimated rate each year for energy purchases and records this amount as purchased power expense in the Combined Power System Statement of Revenues and Expenses. Provisions of the contract require the estimated rate to be adjusted to reflect PG&E's actual annual average thermal production costs, resulting in either Western paying an additional amount or receiving a refund for any overpayment. In the Combined Power System Statement of Revenues and Expense for fiscal year 2005, Western recorded a reduction to purchased power expense for a refund of $25.7 million related to calendar year 2003. During that time period, Western purchased approximately $87.9 million in power from PG&E. No adjustment to the estimated rate has been made for purchases during calendar year 2004. Western is unable to estimate the potential adjustment for those years because the cost data is maintained by PG&E and is outside of Western's control. Accordingly, any adjustment to purchased power expense will be recorded when it becomes known.

(g) FERC Proceedings

As a result of concerns related to the California energy crisis during calendar year 2000, a number of stakeholders, including the State of California, initiated proceedings at FERC to determine if energy sellers improperly manipulated the California wholesale electricity market. FERC initiated its own independent investigation. These proceedings confirmed that a number of independent power producers and electricity marketers manipulated the California wholesale electricity market. As these individual market manipulators were identified and their inappropriate profits calculated, the alleged price manipulators entered into settlement discussions with FERC to disgorge any unjustified profits.

The State of California filed a claim for up to $9 billion against a number of independent power producers at FERC based on its own independent estimate of unjustified price manipulations of the wholesale electricity market. FERC ordered energy companies to refund approximately $3.3 billion, but the State of California appealed this ruling to the 9th Circuit Court of Appeals arguing that the refunds were inadequate as they did not recover sufficient over payments associated with unfair pricing practices. The 9th Circuit ruled in favor of the State of California's position on September 10, 2004, but instead of ordering additional refunds, the court remanded the case back to FERC for further proceedings.

During fiscal year 2005, the State of California reached settlements with eleven independent power producers for a total estimated value of $5.29 billion. The State has also pursued claims against a number of non-jurisdictional energy service providers (e.g., governmental entities). On September 6, 2005, the 9th Circuit Federal Court of Appeals ruled that the Federal Energy Regulatory Commission did not have the authority under the Federal Power Act to order refunds from governmental entities. The State of California is currently reviewing the ruling and considering its options. If the State of California chooses to appeal the ruling and an adverse decision is rendered, any refunds or costs incurred would be adjusted and passed to the appropriate parties.

(h) Central Valley Project

Western is engaged in legal discussions with a customer/supplier regarding disputed transmission rate and grid management charges. There is a reasonable possibility that Western could be liable for additional charges estimated at $50 million.

(8) Pension and Other Retirement Benefits

Western, Reclamation, the Corps and IBWC employees participate in one of the following contributory defined benefit plans: the Civil Service Retirement System (CSRS) or Federal Employees Retirement System (FERS). Agency contributions are based on eligible employee compensation and total 7.0 percent for CSRS and up to 10.7 percent for FERS. These contributions are submitted to benefit program trust funds administered by the Office of Personnel Management (OPM). Western and the generating agencies' contributions for the two plans amounted to $19.9 million and $18.3 million for the years ended September 30, 2005 and 2004, respectively.

The contribution levels as legislatively mandated do not reflect the full cost requirements to fund the CSRS or FERS pension plans (approximately 25.0 and 12.0 percent of base salary, respectively). Other post-retirement benefits administered and partially funded by OPM are the Federal Employees Health and Benefits Program (FEHB) and the Federal Employee Group Life Insurance Program (FEGLI). FEHB is calculated at $4,903 and $4,419 per employee in fiscal year 2005 and 2004, respectively, and FEGLI is based on 0.02 percent of base salary for each employee enrolled in these programs. In addition to the amounts contributed to the CSRS and FERS as stated above, Western and the generating agencies recorded an expense for the pension and other retirement benefits in the Combined Power System Statement of Revenues and Expenses of $16.8 million for the year ended September 30, 2005 and $16.6 million for the year ended September 30, 2004. This amount reflects the contribution made on behalf of Western and the generating agencies by OPM to the benefit program trust funds.

As a Federal Agency, all postretirement activity is managed by OPM. Accordingly, disclosure requirements of FASB SFAS No. 132 are accomplished by OPM.

WESTERN AREA POWER ADMINISTRATION

- Administrator A0000
  - Power Marketing Advisor A0020
  - General Counsel A0200
  - Economic Impact & Diversity A0300
  - Power Marketing Liaison A0500
  - Corporate Communications A0600
  - Chief Information Officer A2000
    - Operations Center A2100
    - Technology Center Regional Support A2200
  - Chief Operating Officer A7000
    - Procurement A7100
    - Human Resources A7200
    - Electric Power Training Center A7300
    - Natural Resources A7400
    - Safety & Security A7700
    - Technical Services A7800
    - Design A7900
  - Chief Financial Officer A8000
    - Budget and Analysis A8100
    - Accounting A8200
    - Compliance & Audit Liaison A8300
  - Upper Great Plains Region B0000 (Billings, MT)
    - Environment B0400
    - Safety & Security B0700
    - Management B1000
    - Information Technology B2000
    - Operations B4000
    - Maintenance B5000
    - Power Marketing B6000
    - Financial Management B8000
  - Rocky Mountain Region J0000 (Loveland, CO)
    - Environment J0400
    - Safety & Security J0700
    - Management J1000
    - Information Technology J2000
    - Operations J4000
    - Maintenance J5000
    - Power Marketing J6000
    - Financial Management J8000
  - Desert Southwest Region G0000 (Phoenix, AZ)
    - Environment G0400
    - Safety & Security G0700
    - Management Services G1000
    - Information Technology G2000
    - Operations G4000
    - Maintenance G5000
    - Power Marketing G6000
    - Financial Management G8000
  - Sierra Nevada Region N0000 (Folsom, CA)
    - Industry Restructuring Advisor N0010
    - Business Practices Advisor N0020
    - Program Support N1000
    - Information Technology N2000
    - Operations N4000
    - Maintenance N5000
    - Power Marketing N6000
    - Financial Management N8000
  - CRSP Management Center L0000 (Salt Lake City, UT)
    - Transmission System Planning L4400
    - Rates Analysis L6100
    - Power Marketing and Contracts L6200
    - Energy Management & Marketing L6300
    - Environment & Resources Planning L6400
    - Financial Management L8001

TO CONTENTS

Contact Western

Call or write your local Western office or the Corporate Communications Office at our Corporate Services Office in Lakewood, Colo., to share your comments or to find out more about Western. Our addresses and phone numbers are listed below.

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For no-cost energy-related technical assistance within Western's service territory, call 1-800-POWERLN (1-800-769-3756), or log on to www.wapa.gov/es.

Western AREA POWER ADMINISTRATION

DEPARTMENT OF ENERGY UNITED STATES OF AMERICA

TO CONTENTS