Through analysis in the EIS, Western determined two of the alternatives were environmentally preferable. The No Action Alternative was determined to be the environmentally preferred alternative with the least environmental impact. It would not, however, meet the purpose and need. Western determined that Alternative 1 is the environmentally preferred action alternative due to fewer environmental impacts on land use, visual resources, and water resources compared to the Proposed Action Option B and the other action alternatives. However, none of the action alternatives, including Alternative 1, would avoid significant air impacts. The environmentally preferred action alternative was not selected because its fewer environmental impacts do not outweigh Western's need to provide maximum load-serving capability that is provided with the selected alternative.

Proposed Action Option B

Project financing for construction is uncertain. With this decision, Western is adopting the EPMs outlined in the EIS. Once funding is secured, Western would complete an air quality analysis to predict potential emissions, conduct biological and cultural resource surveys as necessary, complete a biological assessment and Section 7 consultation with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service, and consult with the State Historic Preservation Office on cultural resources. Stipulations identified through these analyses and consultations would be developed based on agreements reached between Western and the regulatory agencies. Western would develop a mitigation action plan (MAP) for such stipulations to ensure all practical means of avoiding environmental harm. Western would make the MAP available to the public.

This ROD meets the requirements of NEPA as well as the Council on Environmental Quality and DOE's NEPA implementing regulations. Additional analyses results may affect this decision and result in subsequent analysis or decisions. The public will be notified of any additional activities necessary to meet Western's NEPA and other public involvement requirements.

Dated: December 29, 2003.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 04–571 Filed 1–9–04; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Loveland Area Projects Transmission and Ancillary Services—Rate Order No. WAPA–106

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Rate Order.

SUMMARY: Notice is given of the confirmation and approval by the Deputy Secretary of the Department of Energy (DOE) of Rate Order No. WAPA–106 and Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, L–AS6, and L–AS7 placing provisional rates for the Loveland Area Projects (LAP) transmission and ancillary services of the Western Area Power Administration (Western) into effect on an interim basis. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period.

DATES: The provisional rates will be placed into effect on an interim basis on March 1, 2004, and will be in effect until the Federal Energy Regulatory Commission (Commission) confirms, approves, and places the provisional rates into effect on a final basis for a 5-year period ending February 28, 2009, or until superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Daniel T. Payton, Rates Manager, Rocky Mountain Customer Service Region, Western Area Power Administration, 5555 E. Crossroads Boulevard, Loveland, CO 80538, telephone (970) 461–7442, e-mail *dpayton@wapa.gov.*

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6 on March 23, 1998 (Rate Order No. WAPA–80, 63 FR 16778, April 6, 1998); and the Commission confirmed and approved the rate schedules on July 21, 1998, under FERC Docket No. EF98–5181–000 (84 FERC 61,066). The rate schedule for Energy Imbalance Service was revised and approved by the Secretary on May 30, 2002 (Rate Order No. WAPA–97, 67 FR 39970, June 11, 2002), through March 31, 2003.

Additionally, Western has two existing rate schedules for Rocky Mountain Customer Service Region (RMR) services outside Western's Open Access Transmission Tariff (Tariff) that were approved for short-term service by Western's Administrator. These are Rate Schedule L–LO1, Transmission Losses Service, effective October 8, 2000, and Rate Schedule L–US1, Unauthorized Use of Transmission and Control Area Services, effective June 15, 2001. These rates, as well as those under the Tariff and listed above, were extended through March 31, 2004.

Western will replace Rate Schedule L–LO1 with Rate Schedule L–AS7 in this rate action. Rate Schedule L–US1 has been incorporated into revised Rate Schedules L–FPT1, L–NFPT1, and L–AS2 that are part of this rate action. Rate Schedule L–US1 will terminate upon the effective date of this rate order.

There are no significant changes to the formula-based rate methodology for the transmission rates. Western is proposing changes for the formula-based rates for ancillary services. Rates for these services will be recalculated each year to incorporate the most recent financial and load information and will be applicable to all transmission and ancillary services customers.

Provisional Rates for LAP Transmission Service

The provisional rates in Rate Schedules L–NT1, L–FPT1, and L–NFPT1 for LAP transmission services are based on a revenue requirement that recovers (1) the LAP Transmission System costs for facilities associated with providing all transmission services; and (2) the non-facility costs allocated to transmission services. These provisional firm and nonfirm LAP transmission service rates include the costs for scheduling, system control, and dispatch service needed to provide the transmission service. The provisional rates are applicable to existing network, firm and nonfirm LAP transmission services, and future transmission services.

Provisional Rates for Ancillary Services

Western will provide seven ancillary services consistent with FERC Order No. 888. Of the seven ancillary services offered by Western, two are services which must be offered by the transmission provider or control area operator, and must be taken by the transmission customer. These are: (1) Scheduling, System Control, and Dispatch Service, and (2) Reactive Supply and Voltage Control Service from Generation Sources (VAR Support). The remaining five ancillary services, Regulation and Frequency Response Service (Regulation), Energy Imbalance Service, Spinning Reserves Service, Supplemental Reserves Service, and Transmission Losses Service, will be offered by Western, but the customer may also self-provide or purchase these services from another entity. The cost associated with Scheduling, System Control, and Dispatch Service is included in the appropriate transmission service rate.

The provisional rates for LAP transmission and ancillary services rates are developed pursuant to the Department of Energy Organization Act (42 U.S.C. 7101–7352), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts specifically applicable to the project involved, were transferred to and vested in the Secretary of Energy.

By Delegation Order No. 00–037.00, approved December 6, 2001, the Secretary of Energy delegated (1) The authority to develop power and transmission rates on a nonexclusive basis to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Commission. Existing DOE procedures for public participation in power rate adjustments (10 CFR 903) became effective on September 18, 1985 (50 FR 37835).

Rate Order No. WAPA–106, confirming, approving, and placing the proposed LAP transmission and ancillary services rates into effect on an interim basis, is issued, and new Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, L–AS6, and L–AS7 will be submitted promptly to the Commission for confirmation and approval on a final basis.

Dated: December 30, 2003.

Kyle E. McSlarrow,

Deputy Secretary.

Order Confirming, Approving, and Placing the Loveland Area Projects Transmission and Ancillary Service Formula Rates Into Effect on an Interim Basis

These transmission and ancillary service formula rates are established pursuant to Section 302 of the Department of Energy (DOE) Organization Act, 42 U.S.C. 7152(a), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation (Reclamation) were transferred to and vested in the Secretary of Energy (Secretary).

By Delegation Order No. 00–037.00 approved December 6, 2001, the Secretary delegated: (1) The authority to develop power and transmission rates on a non-exclusive basis to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Commission.

Existing DOE procedures for public participation in power rate adjustments are found in 10 CFR 903. Filing Requirements and Procedures for Approving the Rates of Federal Power Marketing Administrations by the Commission are found in 18 CFR 300.

Acronyms/Terms and Definitions

As used in this rate order, the following acronyms/terms and definitions apply:

Acronym/Term	Definition
$/kW-month	Monthly charge for capacity (*i.e.*, $ per kilowatt (kW) per month).
12 cp	Rolling 12-month peak average of customers' loads, coincident with the LAP Transmission System peak.
CRSP	Colorado River Storage Project.
FERC Order No. 888.	FERC Order Nos. 888, 888–A, 888–B, and 888–C, unless otherwise noted.
Firm Electric Service Contract.	Contracts for the sale of long-term firm LAP Federal energy and capacity, pursuant to the Post-1989 General Power Marketing and Allocation Criteria (Marketing Plan).
Federal Customers.	Loveland Area Projects (LAP) customers taking delivery of long-term firm service under Firm Electric Service Contracts, project use, and special use contracts.
Fry-Ark	Fryingpan-Arkansas Project.
FY	Fiscal Year.
kW	Kilowatt; 1,000 watts.
kWh	Kilowatt-hour; the common unit of electric energy, equal to 1 kW taken for a period of 1 hour.
kW-month	Unit of electric capacity, equal to the maximum of kW taken during 1 month.
LAP	Loveland Area Projects.
LAP Transmission System Total Load.	Average 12-cp monthly system peak for network transmission service, average 12-cp monthly entitlements of Federal Customers, and reserved capacity for all firm point-to-point transmission service.
Load ratio share.	Network Transmission Customer's hourly load coincident with Western's monthly transmission system peak, expressed as a ratio.
LSE	Load-Serving Entity is an entity within the control area serving load.
Long-Term Firm Point-to-Point Transmission Service.	Annual firm point-to-point transmission service reservation with 12 consecutive equal monthly amounts.
mill	Unit of monetary value equal to .001 of a U.S. dollar; *i.e.*, 1/10th of a cent.
mills/kWh	Mills per kilowatt-hour.
Monthly Entitlements.	Maximum capacity to be delivered each month under Firm Electric Service Contracts. Each monthly entitlement is a percentage of the seasonal contract-rate-of-delivery.
MW	Megawatt; equal to 1,000 kW or 1,000,000 watts.
Network Integration Transmission Service.	Firm Transmission Service for the delivery of capacity and energy from designated network resources to designated network loads.
Non-Firm Point-to-Point Transmission Service.	Point-to-Point Transmission Service reserved on an as-available basis for periods ranging from 1 hour to 1 month.
OASIS	Open Access Same-Time Information System.
P–SMBP—WD	Pick-Sloan Missouri Basin Project—Western Division.
RMR	Rocky Mountain Customer Service Region.
Service Agreement.	The initial agreement and any amendments or supplements entered into by the Transmission Customer and Western for service under the Tariff.
Short-Term Firm Point-to-Point Transmission Service.	Firm point-to-point transmission service for duration of less than 12 consecutive months.
SSG–WI	Seams Steering Group-Western Interconnection.
Tariff	Western Area Power Administration, Open Access Transmission Service Tariff, Docket No. NJ–98–1–00.

Acronym/Term	Definition
Transmission Customer.	The RMR customer taking network or point-to-point transmission service.
WACM	Western Area Colorado Missouri control area.
WECC	Western Electricity Coordinating Council.

Effective Date

The provisional formula rates will become effective on an interim basis on the first day of the first full billing period beginning on or after March 1, 2004, and will be in effect pending the Commission's approval of them or substitute formula rates on a final basis through February 28, 2009, or until superseded. These formula rates will be applied under existing transmission contracts and Western's Tariff. Western will replace existing Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, and L–AS6 with these new rate schedules for service on the LAP system.

Additionally, Western has two existing rate schedules for ancillary services outside the Tariff that were approved for short-term service by Western's Administrator. These are Rate Schedule L–LO1, Transmission Losses Service, effective October 8, 2000, and Rate Schedule L–US1, Unauthorized Use of Transmission and Control Area Services, effective June 15, 2001. These rates, as well as those under the Tariff and listed above, were extended through March 31, 2004.

Western will replace existing Rate Schedule L–LO1 with Rate Schedule L–AS7 in this rate action. Existing Rate Schedule L–US1 has been incorporated into revised Rate Schedules L–FPT1, L–NFPT1, and L–AS2 that are part of this rate action. Rate Schedule L–US1 will terminate upon the effective date of this rate order.

There are no significant changes to the formula-based rate methodology for the transmission rates. Western is proposing changes for the formula-based rates for ancillary services. Rates for these services will be recalculated each year to incorporate the most recent financial and load information and will be applicable to all transmission and ancillary services customers.

Public Notice and Comment

Western has followed the Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR 903, in the development of these formula rates and schedules.

The following summarizes the steps Western took to ensure involvement of interested parties in the rate process:

1. On May 19, 2003, Western held an informal Public Information Meeting with interested parties to discuss RMR's proposed rates for transmission and ancillary services. Western posted all information presented at the informal Public Information Meeting on its Web site at *http://www.wapa.gov/rm/rm.htm.*
2. RMR published a **Federal Register** notice on June 13, 2003 (68 FR 35398), officially announcing the proposed transmission and ancillary services rates adjustment, initiating the public consultation and comment period, announcing the Public Information and Public Comment forums, and outlining procedures for public participation.
3. On June 18, 2003, RMR sent a letter to all interested parties providing them with a copy of the **Federal Register** notice published on June 13, 2003 (68 FR 35398).
4. On July 14–15, 2003, Western held its Public Information Forums in Denver, Colorado, and Lincoln, Nebraska, respectively, where Western representatives explained the need for the rate adjustment in detail and answered questions from interested parties.
5. On August 6, 2003, Western held a Public Comment Forum in Denver, Colorado, to provide the public an opportunity to comment for the record. Seven individuals commented at this forum.
6. On September 9, 2003, Western posted on its Web site answers to 16 questions posed by a coalition representing wind generation proponents.
7. Twenty-five parties submitted written comments during the 90-day Consultation and Comment Period. The Consultation and Comment Period ended on September 11, 2003. All comments have been considered in the preparation of this rate order.

Comments

Representatives of the following organizations made oral comments:

American Wind Energy Association, Lakewood, Colorado;
Black Hills Power Company, Rapid City, South Dakota;
Lysco, New Brunswick, Ontario;
Municipal Energy Agency of Nebraska, Lincoln, Nebraska;
National Renewable Energy Laboratory, Golden, Colorado;
Nipco California;
Oak Ridge National Laboratory, Oak Ridge, Tennessee;
PanAero Corporation, Englewood, Colorado;
Tri-State Generation and Transmission Association, Inc., Westminster, Colorado;
Xcel Energy, Minneapolis, Minnesota.

The following organizations submitted written comments:

American Wind Energy Association, Lakewood, Colorado;
Basin Electric Power Cooperative, Inc., Bismarck, North Dakota;
Black Hills Power Company, Rapid City, South Dakota;
Broken Bow Municipal Utilities, Broken Bow, Nebraska;
City of Alliance, Nebraska;
City of Aspen, Colorado;
City of Bridgeport, Nebraska;
City of Burwell, Nebraska;
City of Curtis, Nebraska;
City of Gering, Nebraska;
City of Gillette, Wyoming;
City of Gunnison, Colorado;
City of Mitchell, Nebraska;
City of Wood River, Nebraska;
Loveland Area Customers Association;
Mni Sose Intertribal Water Rights Coalition, Inc., Rapid City, South Dakota;
Municipal Energy Agency of Nebraska, Lincoln, Nebraska;
Oak Ridge National Laboratory, Oak Ridge, Tennessee;
PanAero Corporation, Englewood, Colorado;
Platte River Power Authority, Fort Collins, Colorado;
State of South Dakota;
Town of Lyons, Colorado;
Tri-State Generation and Transmission Association, Inc., Westminster, Colorado;
Village of Shickley, Nebraska;
Western Interstate Energy Board, Denver, Colorado.

Project Description

RMR offers transmission service on LAP transmission facilities, which include transmission lines, substations, communication equipment, and related facilities. LAP is comprised of two power projects: the P–SMBP—WD and the Fryingpan-Arkansas Project (Fry-Ark). The two projects were integrated for operational and marketing purposes in 1989. LAP serves Federal and Transmission Customers in a four-State area, over a transmission system of approximately 3,473 miles (5,589 circuit kilometers) and 79 substations.

Western will offer ancillary services from Western Area Colorado Missouri control area (WACM) resources, which represent a combination of some CRSP generation resources and all LAP generation resources.

P–SMBP—WD

The initial stages of the Missouri River Basin Project were authorized by

Section 9 of the Flood Control Act of December 22, 1944 (Pub. L. 534, 58 Stat. 877, 891). The Missouri River Basin Project, later renamed the Pick-Sloan Missouri Basin Program (P–SMBP) to honor its two principal authors, has been under construction since 1944. The P–SMBP encompasses a comprehensive program of flood control, navigation improvement, irrigation, municipal and industrial (M&I) water development, and hydroelectric production for the entire Missouri River Basin. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

The Colorado-Big Thompson, Kendrick, Riverton, and Shoshone Projects were administratively combined with P–SMBP in 1954, followed by the North Platte Project in 1959. These projects are known as the ''Integrated Projects'' of the P–SMBP. The Riverton Project was reauthorized as a unit of the P–SMBP in 1970.

The P–SMBP—WD and the Integrated Projects include 19 powerplants. There are six powerplants in the P–SMBP—WD: Glendo, Kortes, and Fremont Canyon powerplants on the North Platte River; Boysen and Pilot Butte powerplants on the Wind River; and Yellowtail Powerplant on the Big Horn River.

In the Colorado-Big Thompson Project there are also six powerplants: Green Mountain Powerplant on the Blue River is on the West Slope of the Rocky Mountains; and Marys Lake, Estes, Pole Hill, Flatiron, and Big Thompson powerplants on the East Slope of the Continental Divide.

The Kendrick Project has two power production facilities: Alcova and Seminoe powerplants. Power production facilities in the Shoshone Project are Shoshone, Buffalo Bill, Heart Mountain, and Spirit Mountain powerplants. The only production facility in the North Platte Project is the Guernsey Powerplant.

Fry-Ark

The Fry-Ark is a transmountain diversion development in southeastern Colorado authorized by the Act of Congress on August 16, 1962 (Pub. L. 87–590, 76 Stat. 389, as amended by Title XI of the Act of Congress on October 27, 1974 (Pub. L. 93–493, 88 Stat. 1486, 1497). The Fry-Ark diverts water from the Fryingpan River and other tributaries of the Roaring Fork River in the Colorado River Basin on the West Slope of the Rocky Mountains to the Arkansas River on the East Slope of the Continental Divide. The water diverted from the West Slope, together with regulated Arkansas River water, provides supplemental irrigation, M&I water supplies, and produces hydroelectric power. Flood control, fish and wildlife enhancement, and recreation are other important purposes of Fry-Ark. The only generating facility in Fry-Ark is the Mt. Elbert Pumped-Storage Powerplant on the East Slope of the Rocky Mountains.

CRSP

CRSP was authorized by the Colorado River Storage Project Act, ch. 203, 70 Stat. 105, on April 11, 1956. CRSP provides for the comprehensive development of the Upper Colorado River Basin (Upper Basin). It furnishes the long-term regulatory storage needed to allow states in the Upper Basin (Colorado, New Mexico, Utah, and Wyoming) to meet their water delivery obligations to the states of the Lower Basin (Arizona, California, and Nevada) and still use the water apportioned to them by the Colorado River Compact of 1922. The part of CRSP in WACM is the territory north of Shiprock, New Mexico. CRSP hydroelectric facilities providing ancillary services for WACM are the Aspinall Unit (formerly Curecanti) and part of the Glen Canyon Powerplant. The southern portion of CRSP is operated by Western's Desert Southwest Customer Service Region in Phoenix, Arizona.

LAP Transmission Service

RMR prepared a transmission service rate study based on the cost of service for the LAP Transmission System. RMR is seeking approval of formula rates for calculation of point-to-point transmission rates and the network transmission service revenue requirement. The rates will subsequently be recalculated every year, effective October 1, based on the approved formula rates and updated financial and load data. RMR will provide customers notice of changes in rates prior to October 1 of each year.

RMR will continue to bundle transmission service for delivery of LAP long-term firm Federal power to Federal Customers in the firm power rate under existing contracts that expire in 2024. The transmission rates include the cost of Scheduling, System Control, and Dispatch Service.

System Augmentation

Requests for credits for transmission augmentation were made in April 1999 by four entities: Cheyenne Light, Fuel, and Power Company; Platte River Power Authority; Tri-State Generation and Transmission Association, Inc.; and Wyoming Municipal Power Agency. These requests were resolved as follows:

1. Cheyenne Light, Fuel, and Power Company's request was denied in 1999.
2. Based upon further discussion, Platte River Power Authority rescinded its request in 2003.
3. Augmentation credits are being discussed with Tri-State Generation and Transmission Association, Inc., and will be included in the annual revenue requirement, if granted.
4. Western purchased the Big George Substation from Wyoming Municipal Power Agency in 2000, and eliminated the need for augmentation credits.

Western evaluated these requests in accordance with guidance in FERC Order No. 888–A, Section IV.G.1.g.:

> * * * for a customer to be eligible for a credit, its facilities must not only be integrated with the Transmission Provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid.

An estimate for augmentation is included in Western's current revenue requirement for transmission service.

Ancillary Services

RMR will offer seven ancillary services to all customers. The seven ancillary services are: (1) Scheduling, System Control, and Dispatch Service; (2) VAR Support; (3) Regulation; (4) Energy Imbalance Service; (5) Spinning Reserves Service; (6) Supplemental Reserves Service; and (7) Transmission Losses Service. The ancillary services formula rates are designed to recover only the costs incurred for providing the service(s). The rates for ancillary services are based on WACM costs.

In its Notice of Proposed Rates published in the **Federal Register** on June 13, 2003, RMR's rate proposal for Regulation had two components. The first component's charge was load-based, where the customer would be charged for Regulation based upon its 12-cp load calculation. The second component's charge was capacity-based, specifically addressing intermittent renewable resources. The charge was designed to compensate WACM for the lack of predictability and control of intermittent renewable resources.

However, due to a significant number of comments received during the public process, Western has withdrawn the second component of the Regulation rate from this final Notice of Rate Order. Western plans to engage in a dialogue with the public concerning the Regulation rate and its design in early 2004, after which time Western will reopen the Regulation rate for another separate public process to continue through the spring and summer of 2004.

Comparison of Existing and Provisional Rates for Transmission and Ancillary Services

The following table displays a comparison of existing rates and the provisional formula rates using FY 2002 data. These rates will be recalculated annually based on updated financial and load data.

Class of service	Existing rate schedule and rate effective October 1, 2003	Provisional rate schedule and rate effective March 1, 2004
Network Transmission Service	L–NT1 Load ratio share of 1/12 of the revenue requirement of $38,776,237.	L–NT1. Load ratio share of 1/12 of the revenue requirement of $38,776,237.
Firm Point-to-Point Transmission Service.	L–FPT1 $2.68/kW-month	L–FPT1. $2.68/kW-month; Unauthorized Use Penalty will apply.
Non-Firm Point-to-Point Transmission Service.	L–NFPT1 Maximum of 3.75 mills/kWh	L–NFPT1. Maximum of 3.75 mills/kWh; Unauthorized Use Penalty will apply.
Scheduling, System Control, and Dispatch Service.	L–AS1 $40.90 per schedule per day for non-transmission customers.	L–AS1. $25.22 per electronic tag per day for non-transmission customers.
Reactive Supply and Voltage Control Service from Generation Sources.	L–AS2 $0.106/kW-month	L–AS2. $0.106/kW-month; Unauthorized use penalty will apply.
Regulation and Frequency Response Service.	L–AS3 $0.164/kW-month	L–AS3. $0.175/kW-month.
Energy Imbalance Service	L–AS4 Bandwidth of +/−5% with an outside-the-bandwidth penalty of 50%, with LAP weighted average hourly real-time sale and purchase pricing applied. Minimum deviation of 2 MW.	L–AS4. Bandwidth of +/−5% with an outside-the-bandwidth penalty of 25%, with LAP weighted average hourly real-time sale and purchase pricing applied. Minimum deviation of 4 MW.
Operating Reserves Service—Spinning and Supplemental.	L–AS5, L–AS6 Long-term reserves are not available from WACM. Reserves may be provided on a pass-through cost, plus an amount for administration.	L–AS5, L–AS6. Long-term reserves are not available from WACM. Reserves may be provided on a pass-through cost, plus an amount for administration.
Transmission Losses Service	L–LO1 Transmission losses may be settled either financially or with energy. Insufficient losses supplied will be settled financially by default. Prescheduled transactions must have losses delivered concurrently; real-time transactions can return the losses 7 days later, same profile. A 10% administration fee will be applied against the amount of the customer's bill. Pricing used is Palo Verde indices, on- and off-peak.	L–AS7. Transmission losses may be settled either financially or with energy. Insufficient losses supplied will be settled financially by default. All customers will have the option to return the loss obligation for both prescheduled and real-time transactions 7 days later, same profile. Pricing used is LAP weighted average hourly real-time purchase price.
Unauthorized Use of Transmission and Control Area Services.	L–US1 Penalized 150% of demand charge, with a maximum of monthly service, against overruns of reserved capacity.	Incorporated into Rate Schedules L–FPT1, L–NFPT1, and L–AS2. Penalized 150% of demand charge, with a maximum of monthly service, against overruns of reserved capacity.

Certification of Rates

Western's Administrator has certified that the LAP transmission and ancillary services rates placed into effect on an interim basis herein are the lowest possible consistent with sound business principles. The formula rates have been developed in accordance with agency administrative policies and applicable laws.

LAP Transmission Service Discussion

RMR will implement the charges for network and point-to-point transmission service on March 1, 2004. Network service charges will be based on the Transmission Customer's load-ratio share of the annual revenue requirement for transmission. Point-to-point service will be based on reserved capacity on the transmission system.

Annual Transmission Revenue Requirement: The Annual Transmission Revenue Requirement will be applicable to both network and point-to-point transmission service.

The Annual Transmission Revenue Requirement is the Annual Transmission Cost, adjusted for revenue credits and costs associated with expenses which increase the capacity available for transmission. The formula is:

$$\begin{array}{c}\text{Annual}\\\text{Transmission}\\\text{Revenue}\\\text{Requirement}\end{array} = \begin{array}{c}\text{Annual}\\\text{Transmission}\\\text{Cost}\end{array} + \begin{array}{c}\text{Transmission Expenses}\\\text{Which Increase}\\\text{Transmission System}\\\text{Capacity}\end{array} - \begin{array}{c}\text{Miscellaneous}\\\text{Revenue}\\\text{Credits}\end{array} - \begin{array}{c}\text{Revenue Credit}\\\text{For Existing}\\\text{Contracts}\end{array}$$

The Transmission Expenses Which Increase Transmission System Capacity will include credits paid to Transmission Customers for their augmentation of the LAP Transmission System. Crediting arrangements will be addressed in the individual service agreements, and appropriate adjustments will be made in subsequent rate calculations.

Miscellaneous Revenue Credits may include, but not be limited to, non-firm, discounted firm, and short-term firm transmission sales; Scheduling, System Control, and Dispatch Service; or facility charges for transmission facility investments included in the revenue requirement. During the period October 1, 2001, through September 30, 2002, the annual non-firm point-to-point transmission service credit is estimated to be $2,510,181, based on non-firm transmission sales made on the LAP Transmission System; the annual credit for short-term firm transmission sales is estimated to be $4,309,440; credits for scheduling service are estimated to be $180,600; and the credit for facility use charges is $0.

The Annual Transmission Cost is the product of the Annual Fixed Charge Rate and the Net Investment Cost for Transmission Facilities. The formula is:

Annual Transmission Cost = Annual Fixed Charge Rate × Net Investment Cost for Transmission Facilities

The formula applied to FY 2002 data is:

$45,276,458 = 19.812% × $228,530,479

The Net Investment Cost for Transmission Facilities was determined by an analysis of the LAP Transmission System. Each LAP facility was identified by function: transmission, sub-transmission, distribution, or generation-related. Only the investment costs of the facilities identified as ''transmission'' were used in developing the proposed transmission rates. The investment costs of facilities identified as ''sub-transmission'' and ''distribution'' were allocated to LAP Federal Customers. The LAP sub-transmission system is used primarily for delivery of Federal power to Federal Customers. If a Transmission Customer requires the use of the sub-transmission system, an additional facility-use charge will be assessed. All costs of Fry-Ark were considered generation-related and therefore, included with other generation-related costs in the revenue requirement for ancillary services.

The facilities identified as performing the function of transmission include all transmission lines that are normally operated in a continuously-looped manner and the associated substations and switchyard facilities. In the LAP Transmission System, these are primarily the 115–kV and the 230–kV transmission lines. In addition, a portion of the communication and maintenance facilities was included in the investment costs for transmission.

The Annual Fixed Charge Rate includes operation and maintenance (O&M) expenses, administrative and general expenses (A&GE), depreciation expenses, and interest expenses. The formula is:

$$\text{Annual Fixed Charge Rate} = \frac{\begin{array}{c}\text{Annual Operation}\\ \text{\& Maintenance}\\ \text{Expenses}\end{array} + \begin{array}{c}\text{Annual Administrative}\\ \text{\& General}\\ \text{Expenses}\end{array} + \begin{array}{c}\text{Annual}\\ \text{Depreciation}\\ \text{Expenses}\end{array}}{\text{Net Investment}} + \frac{\begin{array}{c}\text{Annual}\\ \text{Interest}\\ \text{Expenses}\end{array}}{\begin{array}{c}\text{Unpaid}\\ \text{Balance}\end{array}}$$

The formula applied to FY 2002 data is:

$$19.812\% = 7.070\% + 1.732\% + 3.371\% + 7.639\%$$

The source for the annual O&M, A&GE, depreciation, and interest expenses is the *Results of Operations for the Rocky Mountain Customer Service Region—Pick-Sloan Missouri Basin.* The source for the unpaid balance is the amount reported in the *Historical Financial Document in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program.*

LAP Transmission System Load: The LAP Transmission System Total Load is the average 12-cp monthly system peak for network transmission service, the 12-cp monthly entitlements for Federal Customers, and the reserved capacity for all firm point-to-point transmission service.

The LAP Transmission System Total Load (12-cp) is calculated as follows, based upon 2002 data and known and measurable changes:

Federal Customers	604,640
Network Transmission Customers	522,496
Subtotal	1,127,136
Point-to-Point Reserved Capacity	79,635
LAP Transmission System Total Load	1,206,771

This LAP Transmission System Total Load for each month is derived as follows:

1. Sum the hourly individual revenue meter readings for network delivery points on the LAP Transmission System to find the LAP system peak hour.

2. Add the Federal Customers' entitlements that do not receive LAP auxiliary transmission.

3. Add the reserved capacity for point-to-point customers.

Network Integration Transmission Service: The monthly charge for Network Integration Transmission Service is the product of the Transmission Customer's load-ratio share times one-twelfth of the Annual Transmission Revenue Requirement. The customer's load-ratio share is the ratio of its network transmission load to the LAP Transmission System Total Load, which will be calculated on a rolling average 12-cp basis.

The customer's network load is derived as follows:

1. Identify the LAP Transmission System's peak hour for each month.

2. Calculate the total delivery to each individual Network Integration Transmission Service customer for the 12 monthly peak hours.

3. Identify the part of the total delivery associated with each customer's monthly LAP entitlement.

4. Identify the network delivery (total delivery less monthly LAP entitlements) during each of the 12 monthly peaks.

5. Sum the 12 monthly peaks and divide by 12 months to derive the average 12 cp for each Network Transmission Service customer.

Firm Point-to-Point Transmission Service: The rate for Firm Point-to-Point Transmission Service is the Annual Transmission Revenue Requirement, divided by the LAP Transmission System Total Load. Firm Point-to-Point Transmission Service is available for a period of 1 day or longer.

The formula for the rate is as follows:

$$\begin{array}{c}\text{Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \frac{\text{Annual Transmission Revenue Requirement}}{\text{LAP Transmission System Total Load}}$$

Non-Firm Point-to-Point Transmission Service: Non-Firm Point-to-Point Transmission Service is available for periods ranging from 1 hour to 1 month. The rate for Non-Firm Point-to-Point Transmission Service may be discounted based on market conditions, but will never be higher than the Firm Point-to-Point Transmission Service rate, converted to an energy equivalent at 100 percent load factor. The formula for the Non-Firm Point-to-Point Transmission Service rate is:

$$\begin{array}{c}\text{Maximum Non-Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \begin{array}{c}\text{Firm Point-to-Point}\\ \text{Transmission Rate}\end{array}$$

Unauthorized Use of Transmission: If a Transmission Customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems, the Transmission Customer shall be charged 150 percent of the demand charge for the type of service at issue (reserved); *e.g.*, hourly, daily, weekly, or monthly, with a maximum monthly demand charge. Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a customer's failure to curtail transmission when requested.

Transmission Service Comments

The following comments were received concerning transmission service during the Public Consultation and Comment Period. Western paraphrased and combined comments when it did not affect the meaning of the comment. Western's response follows each comment.

Comment: Various pieces of study work have been completed that detail large-scale wind development in Western's service areas. This work shows that significant regional transmission planning work is underway to accommodate large scale wind development in Western's service areas. Given its hydro power marketing responsibilities and extensive transmission network, Western is in a unique situation to address wind integration issues.

Response: While this comment is outside the scope of the rate action, Western notes that it has only three existing interconnection requests for 30 MW or greater for wind generation within WACM. Western is heavily involved in all regional transmission planning work currently underway for any wind development within WACM.

Comment: OASIS data shows firm transmission service is often fully subscribed by incumbent firms. Data from SSG-WI shows many regional transmission congestion points in WECC to be physically congested only a small portion of the time, yet non-firm transmission service under FERC Order No. 888 compliant tariffs is only available for periods of less than 1 year. As wind is able to be dispatched off the system, investigation of the use of physically available transmission on a long-term, non-firm basis might show how wind could make use of existing transmission during non-congested times.

Response: While this comment is outside the scope of the rate action, Western notes that FERC Order No. 888 does not provide for the offering of Non-Firm Point-to-Point Transmission Service on a long-term basis. The sale of non-firm transmission service on a long-term basis would complicate the management of scheduling and dispatching and would cause a significant increase in the number of transmission curtailments. Western will accept requests for non-firm short-term transmission. The availability of non-firm short-term transmission is posted on Western's OASIS Web site.

Comment: With regard to generator modeling for stability analysis, wind farm and wind technology design options can vary depending on circumstances. Engineering interconnection software should have the correct wind options in data libraries. An iterative process between wind project developers and grid operators is needed to determine good utility practices for interconnecting wind resources.

Response: While this comment is outside the scope of the rate action, Western is committed to engaging with interested parties in order to determine the best utility practices for the interconnection of wind resources into WACM.

Comment: With regard to cost allocations for transmission upgrades and additions, the allocations for upgrades and additions must take into account both costs imposed by new generators and the system benefits of investments.

Response: Cost allocations for transmission upgrades will be addressed on a case-by-case basis. While the allocation of integration costs themselves is fairly straightforward, the determination of benefits to the system is more complex and will be determined through the use of power flow studies using modeling techniques or other tools available.

Comment: Various commenters interested in the impact of Western's actions on wind generation stand ready to engage with Western in constructive dialogue toward resolution of the issues that Western and wind developers face as large-scale wind development spreads in Western's service territory. They propose an initial workshop co-sponsored by Western, the National Renewable Energy Laboratory, the Oak Ridge National Laboratory, and others. The agenda should allow participants to share data and methods developed elsewhere, to discuss preliminary findings already in hand, and to develop the issues and agendas for working groups to resolve the issues in this rate proceeding and begin the process of addressing the broader issues raised in these comments.

Response: Western continues its ongoing dialogue with wind generation proponents. As stated in this rate order, in response to feedback received during the public process, Western has delayed implementation of the Regulation service capacity-based charge for intermittent renewable resources. Western plans to reopen the rate for Regulation service in its entirety early in 2004 and begin a separate public process.

Comment: A customer comments that it is supportive of changes being proposed for lower transmission rates. Lower rates encourage additional use of the transmission system, which lowers native transmission customers' revenue requirements.

Response: Western appreciates the comment. However, while the annual rate may fluctuate based on financial and load data updates, the rate methodology has not changed.

Ancillary Services Discussion

Seven ancillary services will be offered by WACM; two of which are required to be purchased by the LAP Transmission Customer. These two are: (1) Scheduling, System Control, and Dispatch Service, and (2) VAR Support. The remaining five ancillary services—Regulation, Energy Imbalance Service, Spinning Reserves, Supplemental Reserves, and Transmission Losses Service—will also be offered, but customers have the option of self-supplying or purchasing them from another entity. If WACM is unable to provide these services from its own resources, an offer will be made to purchase the services and pass through these costs to the customer.

The formula rates for ancillary services are based on WACM's costs and are designed to recover only the costs associated with providing the service(s). WACM Federal power resources consist of all the LAP Federal power resources and a portion of the CRSP Federal power resources.

Scheduling, System Control, and Dispatch Service: The cost for providing Scheduling, System Control, and Dispatch Service for Transmission Customers is included in the appropriate transmission service rates. This service can be provided only by the operator of the control area in which the transmission facilities are located. The formula rates will be applied to all tags for WACM non-Federal transmission customers.

The formula rate for Scheduling, System Control, and Dispatch is based on the annual cost of all personnel and related costs involved in providing the service for WACM. The annual cost is divided by the number of electronic tags per year to derive a ''rate per tag'' to be applied per day. The electronic tag represents a specific request for transmission of energy through, within, into, or out of, WACM, per day.

While the revenue requirement calculation is consistent with the 1998 rate order submittal, the charge basis is changing from ''per schedule per day'' to ''per tag per day.''

The charge will be assessed to the last transmission provider displayed in the electronic tag, unless other arrangements are made with WACM.

RMR will accept any number of tag changes over the course of a day, without additional charge, so that entities trying to follow their loads closely may do so without penalty.

Based on FY 2002 data, the rate for Scheduling, System Control, and Dispatch Service for WACM will be $25.22 per tag per day, effective March 1, 2004.

Reactive Supply and Voltage Control Service from Generation Sources: The formula rate for VAR Support is based upon Reclamation's net generation plant investment in WACM. Annual Fixed Charge Rates based on annual generation-related O&M, A&GE, depreciation, and interest expenses for LAP and CRSP are applied to Reclamation's net generation plant investment to calculate annualized costs. The percentage of WACM generation capacity that is utilized for VAR Support is then identified. This percentage is applied to the annualized costs for LAP and CRSP, and those results are summed to derive the annual revenue requirement for VAR Support for WACM. The annual revenue requirement is then divided by the WACM 12-cp load being provided VAR Support, to yield a $/kW-year rate, which is divided by 12 months to yield a $/kW-month rate. Based upon FY 2002 data, the WACM rate for VAR Support is $0.106/kW-month.

Full or partial credit may be given to those customers with generators providing WACM with VAR Support. Any crediting arrangement must be documented in the customers' Service Agreements.

Regulation and Frequency Response Service: The rate for Regulation is a load-based rate, and will be applied against customer's loads within WACM.

The formula rate for Regulation is based upon a current analysis that shows WACM presently requires approximately 75 MW of regulating capacity to meet the control area needs. The amount of regulation and cost of associated purchases will be revised annually to accurately reflect the capacity needed to supplement hydroelectric resources.

The revenue requirement for that regulating capacity is comprised of: (1) The annualized cost of LAP regulating plants in WACM; (2) the revenue requirement for CRSP regulating plants within WACM; and (3) the cost of a capacity purchase to support regulation. Net investment costs for only those plants that are able to provide regulating service were included in (1) and (2), above.

For LAP, the same Annual Fixed Charge Rate used in the VAR Support formula was used to convert the LAP net plant investment to an annual cost for Regulation. The annual cost was divided by the nameplate capacity of the applicable plants to yield an average cost per kilowatt for LAP. LAP's revenue requirement for the provision of 25 MW is $1,189,750.

For CRSP, the revenue requirement was provided to RMR from the CRSP Management Center in Salt Lake City using the same methodology, but with CRSP's net investment and Annual Fixed Charge Rate. Historical operational experience shows that the amount of regulating capacity provided for CRSP loads is 40 MW. With the division of CRSP's load into two control areas on April 1, 1998, WACM received one-half of the 40 MW of capacity, or 20 MW. CRSP's valuation of the revenue requirement for WACM's 20 MW is $480,185.

Additionally, a 30 MW purchase of capacity was made at a net cost of $3,416,400.

The total of these three components to provide WACM with 75 MW of regulating capacity is $5,086,335. The load in WACM requiring regulation is 2,425,221 kW (12-cp value).

Based upon FY 2002 data, the rate for Regulation effective March 1, 2004, will be $0.175/kW-month.

Customers who provide WACM with Regulation will receive a credit. These types of crediting arrangements must be documented in Transmission Customers' Service Agreements.

Energy Imbalance Service: The Commission established guidelines in FERC Order No. 888 for Energy Imbalance Service of +/−1.5 percent hourly deviation (3 percent bandwidth) with a 2 MW minimum deviation, as in its view, anything more or less than that could affect system reliability. However, RMR recognizes that metering inadequacies, changes in scheduling practices, and unit control problems may hinder customers' ability to meet the 3 percent bandwidth. Therefore, RMR has established a +/−5-percent hourly deviation (10 percent bandwidth) with a 4 MW minimum deviation. Energy Imbalance Service taken within the bandwidth will be charged or credited 100 percent of the LAP weighted hourly average real-time purchase or sale price that hour. Energy Imbalance Service taken outside the bandwidth will be charged a 25 percent penalty.

In the previously approved rate schedule for this service, the minimum deviation was 2 MW and the penalty for excursions outside the bandwidth was 50 percent.

In this rate order, the 2 MW minimum is increased to a 4 MW minimum to afford smaller customers increased operating flexibility. Western decreased the out-of-bandwidth penalty from 50 percent to 25 percent after conducting an analysis of imbalances since implementation (July 2002). The out-of-bandwidth excursions did not appear to significantly impact Western's operations; therefore, Western decreased the penalty.

All Energy Imbalance Service provided by WACM, both inside and outside the bandwidth, will be settled financially and accounted for hourly after the fact. The +/−5 percent will be applied against a customer's actual load, and will be calculated hourly to any energy imbalance that occurs as a result of a customer's schedules and/or meter data.

There are normally four scenarios for Energy Imbalance Service, each of which receives a specific pricing calculation. These scenarios are: (1) Over delivery within the bandwidth; (2) under delivery within the bandwidth; (3) over delivery outside the bandwidth; and (4) under delivery outside the bandwidth. The respective pricing for each scenario is: for (1) and (2) 100 percent of LAP weighted hourly average real-time sale or purchase price would apply, dependent upon the control area energy condition in aggregate; for (3) 75 percent of LAP weighted hourly average real-time sale price would apply; and for (4) 125 percent of the LAP weighted hourly average real-time purchase price would apply.

When there are no real-time sales or purchases within an hour, the pricing defaults both within and outside the bandwidth will be applied in the following order:

1. Weighted hourly average real-time sale or purchase pricing for the day (on and off peak).
2. Weighted hourly average real-time sale or purchase pricing for the current month (on and off peak).
3. Weighted hourly average real-time sale or purchase pricing for the prior month.
4. Weighted hourly average real-time sale or purchase pricing for the month immediately prior to the prior month (and continuing in this manner until sale or purchase pricing is located) for on and off peak.

Western supports the development of intermittent renewable energy sources, but does not have the resource capability to cover fluctuations anticipated with such resources. However, Western is willing to purchase, on a pass-through cost basis, the requirements to mitigate the fluctuations inherent in intermittent resources. No bandwidth will apply. This will assure that intermittent resource providers pay only for the Energy Imbalance Service they take. They will not be penalized for any out-of-bandwidth activity.

For jointly-owned generators and any other generators within the control area without designated load, the bandwidth established for Energy Imbalance Service will be +/−2 percent of the actual hourly generation output of the units at issue. The charges or credits for Energy Imbalance Service will be assigned to the operating agent of the generator, unless WACM is provided with a copy of a signed agreement from all of the generation owners designating a specific methodology to allocate among owners and entitlees. Western reserves the right to refuse a designation that does not provide for the full and accurate recovery of all generator energy imbalances existing among owners and/or entitlees. The generation owners will be responsible for proper tagging and scheduling of the generation to ensure the accurate assignment of Energy Imbalance Service.

Bandwidth expansion will be made for physical resource loss, contribution to the control area for frequency reserves requirements, and for the transition of large generating resources.

During periods of control area operating constraints, Western reserves the right to eliminate credits for over deliveries. Additionally, parties who over or under deliver may share in potential penalty costs assessed against Western for operation outside of established utility guidelines.

Operating Reserves—Spinning and Supplemental: WACM has no long-term reserves available beyond its own internal requirements, based on the post-1999 Resource Study done in July 1995.

At a customer's request, an offer will be made to purchase reserves and pass through that cost, plus an amount for administration. Additionally, the customer would be responsible for providing the transmission to deliver these reserves.

Transmission Losses Service: Transmission losses will be assessed for all real-time and prescheduled transactions on transmission facilities managed by Western or within WACM. Transmission Customers will be allowed the option of energy repayment either concurrently or 7 days later, using the same profile. Transmission Customers must declare their preference annually, as to which method of energy payback they prefer. When a transmission loss energy obligation is not provided (or under provided) by a Transmission Customer for a transmission transaction, the cost of energy still owed for losses will be calculated based upon the LAP weighted average hourly real-time purchase price. Pricing for loss energy due 7 days later, and not received by WACM, will be priced at the 7-day-later price (the LAP weighted average hourly real-time purchase price with the same defaults as Energy Imbalance Service). There will be no financial compensation or energy returned to Transmission Customers for over delivery of transmission losses, as there should be no condition beyond the control of the Transmission Customer that results in overpayment.

There will be no administrative charge for Transmission Losses Service.

Ancillary Service Comments

RMR received written comments concerning the ancillary services during the Public Consultation and Comment Period. These comments have been paraphrased where appropriate, without compromising the meaning of the comments. Certain comments were duplicative in nature, and were combined. RMR's response follows each comment.

Comment: Large-scale wind development is on the horizon, including very large wind resources in all of Western's states. Western should be taking a leadership role in addressing wind integration issues.

Response: Western is committed to working with all interested parties to ensure that wind development in Western's control areas is supported in a fair and equitable manner. As mentioned earlier in this rate order, Western plans to engage in a dialogue with the public concerning a Regulation rate design for intermittent renewable resources in early 2004, after which time Western will reopen the Regulation rate for another separate public process to continue through the spring and summer of 2004.

Comment: A commenter states that requirements to schedule generation a day or more ahead of delivery, challenges the development of wind resources in the absence of agreement on wind forecasting methods and implementation, and can unnecessarily raise ancillary service costs for wind.

Response: Western requires the preschedule of generation in adherence to NERC and WECC policies regarding deadlines for submittal of tags for energy and transmission schedules. However, NERC Policy 3 allows changes to schedules up to 20 minutes prior to the hour in an hourly scheduling environment. Western, therefore, believes that considerable scheduling flexibility is available for balancing resources and loads.

Comment: Many comments were received concerning the proposed rate for Regulation and Frequency Response Service for Intermittent Renewable Resources. These comments included concerns about rate design, implementation, and undue financial penalties and/or charges for intermittent renewable resources.

Response: As indicated earlier in this rate order, due to the large number of comments received concerning this component of the Regulation rate, Western has withdrawn the capacity-based rate component from the Rate Schedule for Regulation and Frequency Response Service to be implemented March 1, 2004. Western will further study the issue and early in 2004 will engage in an informal process with the public concerning the Regulation rate and its design. After receiving informal public input, Western will reopen the Regulation rate for a formal public process.

Comment: A commenter believes that Western should charge an administrative fee for Energy Imbalance Service, similar to the way CRSP assesses administrative charges for its Western Replacement Power and/or Customer Displacement Power products.

Response: Western has reviewed this issue and determined that it will not assess an administrative charge for Energy Imbalance Service. Western views Energy Imbalance Service as an integral function and responsibility of the WACM control area, recoverable under O&M.

Comment: With regard to Energy Imbalance Service for jointly owned generators, a commenter suggests that Western use 2 percent of the unit rating, instead of the current policy of using 2 percent of the actual generation output, as the bandwidth margin.

Response: Western will continue to use 2 percent of the actual generation output as the bandwidth margin for Energy Imbalance Service. Western believes that this is more reasonable than applying 2 percent to the unit's rating.

As an example, if a 400 MW plant has an actual output in an hour of only 50 MW, the use of the unit's 400 MW nameplate capacity results in a bandwidth of 8 MW for a 50 MW output, or a 16 percent bandwidth. When the 2 percent is applied in this same example to the 50 MW of actual generation output, the result is a bandwidth of +/−1 MW.

Comment: A commenter suggests opening the bandwidth for Energy Imbalance Service to forgive shortfalls of large coal units' generation, if the shortfall is caused by station service associated with a large coal unit being off line.

Response: Station service loads are the responsibility of the plant owner's LSE. These loads are covered for up to the initial 2 hours of an unplanned outage under membership in the Rocky Mountain Reserve Sharing Group. It is the LSE's responsibility to schedule for these loads after this initial period. Therefore, Western will not open the bandwidth for imbalances resulting from the incorrect scheduling of station service loads.

Comment: A commenter suggests that Western expand the minimum deviation for Energy Imbalance Service from 2 MW to 4 MW.

Response: Western agrees with the commenter and is expanding the minimum deviation for Energy Imbalance Service from 2 MW to 4 MW, to provide smaller customers greater flexibility in balancing their loads and resources.

Comment: Western should clarify what it means by "eliminating the bandwidth for intermittent renewables' imbalances" for Energy Imbalance Service. Does this mean that there will be zero deviation from schedules allowed or that infinite deviation will be allowed?

Response: For Energy Imbalance Service calculated for intermittent renewable resources within WACM, Western will apply no bandwidth. What this means is that hour-to-hour, the intermittent renewable resource will pay 100 percent or receive 100 percent of the LAP weighted average hourly purchase or sale price, respectively. No penalty will apply to Energy Imbalance Service taken by an intermittent renewable resource.

Comment: A commenter asks for a credit for the self-provision of Regulation service.

Response: Western notes that there is a crediting provision in the existing rate for Regulation service for entities that are able to self-provide this service or are purchasing it from another party. This eligibility for a credit is also contained in the rate schedule for Regulation that is part of this rate order. Any such crediting arrangement will need to be documented in the entity's Service Agreement.

Comment: A commenter notes that Western will charge "market" rates for imbalances. The commenter has a concern that Western should never be allowed to over collect revenues by forcing wind generators into the currently imperfect imbalance market, and keeping the spread whenever imbalances partly or completely cancel each other out.

Response: The rates that Western charges for Energy Imbalance Service are the LAP weighted average hourly real-time purchase and sales prices; that is, they are Western's actual costs and revenues for power. As such, Western is neither making a profit on energy over delivered for Energy Imbalance Service, nor is it suffering a loss on energy under delivered for Energy Imbalance Service. Western, acting as the WACM control area operator, merely balances out the loads and resources, by either selling or purchasing energy, and passing the costs on to customers as appropriate for their specific energy condition.

Comment: A commenter would like a full description about how the Energy Imbalance Service financial settlement will work. Western should allow netting imbalances for intermittent renewables over a monthly billing period to simplify the administration and financial impact of imbalance payments.

Response: Western's Energy Imbalance Service accounting is accomplished based upon a financial settlement methodology, performed hourly, 3 to 4 months after the fact. Each hour's imbalance is calculated using LAP weighted average hourly real-time purchase or sales pricing. Due to hourly variations in the value of energy, Western will not allow the netting of energy over the course of a month. This could result in a financial loss or gain for the control area, and Western's methodology is based on cost-recovery for over or under deliveries.

Comment: A commenter states that arbitrary, non-cost based penalties for not meeting schedules by intermittent generators (who do not have the ability to ''game'' the system) in the absence of market-based real-time settlements for Energy Imbalance Service, can and should be eliminated for wind without negatively impacting grid operations or costs.

Response: Western uses market-based real-time settlements for Energy Imbalance Service financial calculations. This allows customers with energy imbalances to be charged or credited for only the identical purchase or sale that WACM had to make in order to balance the control area. It is not Western's intent to make a profit with Energy Imbalance Service, but only to recover actual costs from appropriate parties. Western reiterates that there will be no penalties associated with Energy Imbalance Service caused by intermittent renewable resources.

Comment: A commenter is very concerned about the proposal to round hourly Energy Imbalance Service to the nearest whole MW. Western has said the effect is negligible, but it will mean a cost increase to the commenter of 270 percent. This is a significantly negative impact to the commenter. The commenter would like to know the apparent, compelling reason to change the methodology.

Response: Western had originally proposed rounding Energy Imbalance Service up to the nearest whole MW hourly, predicated upon a concern from a customer regarding the inability to have zero energy imbalance in an hour due to the scheduling of energy in MWs and the actual meter readings in kWs.

Upon further study, Western has determined that the rounding of Energy Imbalance Service hourly values can be beneficial in some hours, but detrimental in others.

In this final rate order, the hourly Energy Imbalance Service values and subsequent billing will remain in kWs. When the customer over delivers kWs, it is credited for those kWs in that hour; when the customer under delivers kWs, it is charged for those kWs in that hour.

Regulatory Flexibility Analysis

Under the Regulatory Flexibility Act of 1980 (5 U.S.C. 601–612), each agency, when required by 5 U.S.C. 553 to publish a proposed rule, is further required to prepare and make available for public comment an initial regulatory flexibility analysis to describe the impact of the proposed rule on small entities. In this instance, the initiation of the LAP transmission rate and ancillary service rate adjustment is related to non-regulatory services provided by Western at a particular rate. Under 5 U.S.C. 601(2), rules of particular applicability relating to rates or services are not considered rules within the meaning of the Act. Since the LAP transmission rates and ancillary rates are of limited applicability, no flexibility analysis is required.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

Environmental Evaluation

In compliance with the National Environmental Policy Act (NEPA) of 1969, 42 U.S.C. 4321, *et seq.*; the Council on Environmental Quality Regulations (40 CFR 1500–1508); and DOE NEPA Regulations (10 CFR 1021), Western has determined that this action is categorically excluded from the preparation of an environmental assessment or an environmental impact statement.

Executive Order 12866

DOE has determined that this is not a significant regulatory action because it does not meet the criteria of Executive Order 12866, 58 FR 51735. Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Submission to Federal Energy Regulatory Commission

The formula rates herein confirmed, approved, and placed into effect on an interim basis, together with supporting documents, will be submitted to the Commission for confirmation and approval on a final basis.

Order

In view of the foregoing, and pursuant to the authority delegated to me by the Secretary of Energy, I confirm, approve, and place into effect on an interim basis, effective March 1, 2004, formula rates for transmission and ancillary services under Rate Schedules L–NT1, L–FPT1, L–NFPT1, L–AS1, L–AS2, L–AS3, L–AS4, L–AS5, L–AS6, and L–AS7. The rate schedules shall remain in effect on an interim basis, pending the Commission's confirmation and approval of them or substitute formula rates on a final basis through February 28, 2009.

Dated: December 30, 2003.

Kyle E. McSlarrow,
Deputy Secretary.

Rate Schedule L–AS1, Schedule 1 to Tariff, March 1, 2004; Rocky Mountain Region, Loveland Area Projects Scheduling, System Control, and Dispatch Service

Applicable

This service is required to schedule the movement of power through, out of, within, or into the Western Area Colorado Missouri control area (WACM). The charges for Scheduling, System Control, and Dispatch Service are to be based on the rate referred to below.

The rate will be applied to all electronic tags for WACM non-transmission customers. The Rocky Mountain Region (RMR) will accept any number of tagging changes over the course of the day without any additional charge.

The Loveland Area Projects' charges for Scheduling, System Control, and Dispatch Service may be modified upon written notice to the customer. Any change to the charges for the Scheduling, System Control, and Dispatch Service will be listed in a revision to this rate schedule issued under applicable Federal laws, regulations, and policies and made part of the applicable service agreement.

RMR will charge the non-transmission customer the rate then in effect. The charge will be assessed to the last transmission provider displayed in the electronic tag, unless other arrangements are made with WACM.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

$$\text{Cost per Tag} = \frac{\text{Annual Cost of Scheduling and Dispatch Personnel, and Related Costs}}{\text{Number of Tags per Year}}$$

Rate

The rate to be in effect March 1, 2004, through September 30, 2004, is $25.22 per tag per day. This rate is based on the above formula and on FY 2002 data.

Rate Schedule L–AS2, Schedule 2 to Tariff, March 1, 2004; Reactive Supply and Voltage Control From Generation Sources Service

Applicable

To maintain transmission voltages on all transmission facilities within acceptable limits, generation facilities under the control of the Western Area Colorado Missouri control area (WACM) are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (VAR Support) must be provided for each transaction on the transmission facilities. The amount of VAR Support supplied to the Customer's (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within the WACM) transactions will be based on the VAR Support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by WACM.

The Customer must purchase this service from the WACM operator. The charges for such service will be based upon the rate outlined below.

The LAP charges for VAR Support may be modified upon written notice to the Customer. Any change to the charges for VAR Support will be listed in a revision to this rate schedule issued under applicable Federal laws, regulations, and policies and made part of the applicable service agreement. The Rocky Mountain Region will charge the Customer under the rate then in effect.

Credit may be given to those Customers with generators providing WACM with VAR Support. Any crediting arrangements must be documented in the Customer's Service Agreement.

Unauthorized Use of Control Area Services

If a Customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems, the Customer shall be charged 150 percent of the demand charge for the type of service at issue (reserved); *e.g.*, hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a Customer's failure to curtail transmission when requested.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

Total Annual Revenue Requirement for Generation = TARRG

Percentage of Resource Capacity Used for VAR Support = % of Resource

$$\begin{array}{c}\text{WACM}\\ \text{VAR Support}\\ \text{Rate}\end{array} = \frac{\text{TARRG} \times \text{\% of Resource}}{\text{Load in the Control Area Requiring VAR Support}}$$

Rate

The rate to be in effect March 1, 2004, through September 30, 2004, is:

Monthly: $0.106/kW-month
Weekly: $0.024/kW-week
Daily: $0.003/kW-day
Hourly: $0.000125/kWh

This rate is based on the above formula and on FY 2002 financial and load data.

Rate Schedule L–AS3, Schedule 3 to Tariff, March 1, 2004; Regulation and Frequency Response Service

Applicable

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources, generation, and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Western Area Colorado Missouri control area (WACM) operator. The Customers (Loveland Area Projects (LAP) Transmission Customers and customers on others' transmission systems within WACM) must either purchase this service from WACM or make alternative comparable arrangements to satisfy their Regulation obligations. The charges for Regulation are outlined below.

The LAP charges for Regulation may be modified upon written notice to the Customer. Any change to the Regulation charges will be listed in a revision to this rate schedule issued under applicable Federal laws, regulations, and policies and made part of the applicable service agreement. The Rocky Mountain Region (RMR) will charge the Customer under the rate then in effect.

Credit will be given to those Customers who provide WACM with Regulation. These types of crediting arrangements must be documented in the Customer's Service Agreement.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

$$\begin{array}{c}\text{WACM}\\ \text{Regulation}\\ \text{Rate}\end{array} = \frac{\text{Total Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Rate

The rate to be in effect March 1, 2004, through September 30, 2004, is:

Monthly: $0.175/kW-month
Weekly: $0.040/kW-week
Daily: $0.006/kW-day
Hourly: $0.000250/kWh

This rate is based on the above formula and on FY 2002 financial and load data.

Rate Schedule L–AS4, SCHEDULE 4 to Tariff, March 1, 2004; Energy Imbalance Service

Applicable:

This rate applies to all customers receiving Energy Imbalance Service from the Rocky Mountain Customer Service Region's Western Area Colorado Missouri control area (WACM).

WACM provides Energy Imbalance Service when there is a difference between a Customer's (Loveland Area Projects Transmission Customers and customers on others' transmission systems within WACM) resources and obligations. Energy Imbalance is calculated as resources minus obligations (adjusted for transmission and transformer losses) for any combination of scheduled transfers, transactions, or actual load integrated over each hour. Customers within WACM must either obtain this service from WACM or make alternative comparable arrangements to satisfy their Energy Imbalance Service obligation.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

All Energy Imbalance Service provided, both inside and outside the bandwidth, will be settled financially, accounted for hourly at the end of each month. WACM will establish a deviation band of ± 5 percent (with a minimum of 4 MW) of the actual load to be applied hourly to any energy imbalance that occurs as a result of a Customer's schedules and/or meter data.

Normally, there are four scenarios for Energy Imbalance Service. They are: (1) over delivery within the bandwidth; (2) under delivery within the bandwidth; (3) over delivery outside the bandwidth; and (4) under delivery outside the bandwidth. During periods of control area operating constraints, Western reserves the right to eliminate credits for over deliveries and parties over or under delivering may share in the cost to Western of any penalty.

Within the Bandwidth

The gross energy imbalance for each applicable entity within WACM shall be totaled and netted to determine an aggregate energy imbalance for WACM. The sign of the aggregate energy imbalance will determine whether sale or purchase pricing will be used (surplus conditions use sale pricing and deficit conditions use purchase pricing).

Depending upon the sign of the aggregate energy imbalance for all entities within WACM, the pricing for charges and credits within the bandwidth will be: Weighted Average Real-Time Sale or Purchase Price.

Outside the Bandwidth

Each entity within WACM will be charged or credited independently for Energy Imbalance Service taken, depending on its over-or under-delivery status.

Under Delivery (customer deficit) = Customer will be charged 125% of the weighted average real-time purchase price.

Over Delivery (customer surplus) = Customer will be credited 75% of the weighted average real-time sale price.

Expansion of the bandwidth will be allowed during the following instances:

—The loss of a physical resource.
—Upon evidence of proven frequency bias contribution for control area needs.
—The transition (start up/shut down) period for large generating resources.

Jointly-Owned Generation or Generation Without Designated Load

For jointly-owned generators and any other generators within the control area without designated load, the bandwidth established for Energy Imbalance Service will be +/−2 percent of the actual hourly generation output of the units at issue. The charges or credits for Energy Imbalance Service will be assigned to the operating agent of the generator, unless WACM is provided with a copy of a signed agreement from all of the owners designating a specific methodology to allocate among owners and entitlees. Western reserves the right to refuse a designation that does not provide for the full and accurate recovery of all generator energy imbalances existing among owners and/or entitlees. The generator owners will be responsible for proper tagging and scheduling of the generation to ensure that the Energy Imbalance Service is assigned accurately.

Pricing Defaults

When no hourly data is available, the pricing defaults for sales and purchase pricing both within and outside the bandwidth will be applied in the following order:

1. Weighted average real-time sale or purchase pricing for the day (on and off peak).
2. Weighted average real-time sale or purchase pricing for the month (on and off peak).
3. Weighted average real-time sale or purchase pricing for the prior month.
4. Weighted average real-time sale or purchase pricing for the month prior to the prior month (and continuing until sale or purchase pricing is located) (on and off peak).

Rate

This bandwidth applicable to load is in effect March 1, 2004, through February 28, 2009, and is +/−5 percent of hourly actual load, with a 4 MW minimum deviation.

The bandwidth applicable to jointly owned generators or generators without designated load is in effect March 1, 2004, through February 28, 2009, and is +/−2 percent of hourly actual generation, with a 4 MW minimum deviation.

The pricing and penalty for deviations inside and outside the bandwidth is described above.

Rate Schedule L-AS5, Schedule 5 to Tariff, March 1, 2004; Operating Reserve—Spinning Reserve Service

Applicable

Spinning Reserve Service (Reserves) is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The Customers (Loveland Area Projects Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy their Reserve obligations. The charges for Reserves are shown below. The amount of Reserves will be outlined in the service agreement.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

At a Customer's request, Western may purchase Reserves and pass through that cost, plus an amount for administration. Additionally, the Customer would be responsible for providing the transmission to deliver the Reserves.

Rate Schedule L–AS6, Schedule 6 to Tariff, March 1, 2004; Operating Reserve—Supplemental Reserve Service

Applicable

Supplemental Reserve Service (Reserves) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Reserves may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Customers (Loveland Area Projects' Transmission Customers and customers on others' transmission system within Western Area Colorado Missouri control area (WACM)) must either purchase this service from WACM or make alternative comparable arrangements to satisfy their Reserve obligations. The charges for Reserves are outlined below. The amount of Reserves will be listed in the service agreement.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

No long-term Reserves are available beyond internal WACM requirements.

At a Customer's request, Western may purchase Reserves and pass through that cost, plus an amount for administration. Additionally, the Customer would be responsible for providing the transmission to deliver the Reserves.

Rate Schedule L–AS7, Schedule 9 to Tariff, March 1, 2004; Transmission Losses Service

Applicable

This rate schedule covers providing transmission losses for transactions within WACM as posted on the Rocky Mountain Region OASIS Web site.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

Transmission losses will be assessed for all real-time and prescheduled transactions on transmission facilities managed by Western-RMR or within WACM. Transmission Customers will be allowed the option of energy repayment either concurrently or 7 days later, same profile. Transmission Customers must declare their preference annually, as to which method of energy payback they wish to use.

However, when a transmission loss energy obligation is not provided (or is under provided) by a Transmission Customer for a transmission transaction, the energy still owed for losses will be calculated and a charge will be assessed to the Transmission Customer, based on the LAP weighted average hourly real-time purchase price.

Pricing for loss energy due 7 days later, and not received by WACM, will be priced at the 7 day later-price (the LAP weighted average hourly real-time purchase price with same defaults as Energy Imbalance Service).

There will be no financial compensation or energy return to Transmission Customers for over delivery of transmission losses, as there should be no condition beyond the control of the Transmission Customer that results in overpayment.

Rate

This rate is in effect March 1, 2004, through February 28, 2009. Transmission Customers may settle financially or with energy. The pricing for this service will be the LAP weighted average hourly real-time purchase price with the same defaults as Energy Imbalance Service.

Rate Schedule L–FPT1, Schedule 7 to Tariff, March 1, 2004; Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service

Applicable

The Transmission Customer shall compensate the Rocky Mountain Region (RMR) each month for Reserved Capacity under the applicable Firm Point-to-Point Transmission Service Agreement and rates outlined below. The formula rates used to calculate the charges for service under this schedule were issued and may be modified under applicable Federal laws, regulations, and policies.

RMR may modify the charges for Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Firm Point-to-Point Transmission Service will be listed in a revision to this rate schedule and made part of the applicable service agreement. RMR shall charge the Transmission Customer under the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by RMR must be announced to all eligible customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, RMR must offer the same discounted transmission service rate for the same time period to all eligible customers on all unconstrained transmission paths that go to the same point(s) of delivery on the transmission system.

Unauthorized Use of Transmission

If a Transmission Customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems, the Transmission Customer shall be charged 150 percent of the demand charge for the type of service at issue (reserved); *e.g.*, hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a Transmission Customer's failure to curtail transmission when requested.

Formula Rate

$$\begin{array}{c}\text{Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \frac{\text{Annual Transmission Revenue Requirement}}{\text{LAP Transmission System Total Load}}$$

If a Transmission Customer requires use of subtransmission facilities, a specific facility use charge will be assessed in addition to this formula rate.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Rate

The rate to be in effect March 1, 2004, through September 30, 2004, is as follows:

Maximum of:

Yearly: $32.13/kW of reserved capacity per year
Monthly: $2.68/kW of reserved capacity per month
Weekly: $0.62/kW of reserved capacity per week
Daily: $0.09/kW of reserved capacity per day

This rate is based on the above formula and FY 2002 data.

Rate Schedule L–NFPT1, Schedule 8 to Tariff, March 1, 2004; Non-Firm Point-to-Point Transmission Service

Applicable

The Transmission Customers will compensate Rocky Mountain Region (RMR) for Non-Firm Point-to-Point Transmission Service under the applicable Non-Firm Point-to-Point Transmission Service Agreement and rate outlined below. The formula rates used to calculate charges for service under this schedule were issued and may be modified under applicable Federal laws, regulations, and policies.

RMR may modify the charges for Non-Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Non-Firm Point-to-Point Transmission Service will be listed in a revision to this rate schedule and made part of the applicable service agreement. RMR will charge the Transmission Customer under the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service: (1) Any offer of a discount made by RMR must be announced to all eligible customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any customer-initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, RMR must offer the same discounted transmission service rate for the same time period to all eligible customers on all unconstrained transmission paths that go to the same point(s) of delivery on the transmission system.

Unauthorized Use of Transmission

If a Transmission Customer (including the transmission provider for third-party sales) engages in unauthorized use of RMR-managed transmission systems, the Transmission Customer will be charged 150 percent of the demand charge for the type of service at issue (reserved); *e.g.*, hourly, daily, weekly, or monthly, with a maximum demand charge set at monthly.

Unauthorized use is defined as unscheduled or untagged use of the transmission system and any affiliated ancillary service, exceeding reserved capacity at any point of delivery or receipt. Unauthorized use may also include a Transmission Customer's failure to curtail transmission when requested.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

$$\begin{array}{c}\text{Maximum Non-Firm}\\ \text{Point-to-Point}\\ \text{Transmission Rate}\end{array} = \begin{array}{c}\text{Firm Point-to-Point}\\ \text{Transmission Rate}\end{array}$$

Rate

The rate to be in effect March 1, 2004, through September 30, 2004, is:

Maximum of:

Monthly: $2.68/kW of reserved capacity per month

Weekly: $0.62/kW of reserved capacity per week

Daily: $0.09/kW of reserved capacity per day

Hourly: 3.75 mills/kWh

This rate is based on the above formula and FY 2002 data.

Rate Schedule L–NT1, Attachment H to Tariff, March 1, 2004; Annual Transmission Revenue Requirement for Network Integration Transmission Service

Applicable

Transmission Customers will compensate the Rocky Mountain Region (RMR) each month for Network Transmission Service under the applicable Network Integration Service Agreement and annual revenue requirement referred to below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was issued and may be modified under applicable Federal laws, regulations, and policies.

RMR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service will be listed in a revision to this rate schedule and made part of the applicable service agreement. RMR will charge the Transmission Customer in accordance with the revenue requirement then in effect.

Effective

The first day of the first full billing period beginning on or after March 1, 2004, through February 28, 2009.

Formula Rate

$$\text{Monthly Charge} = \text{Transmission Customer's Load-Ratio Share} \times \frac{\text{Revenue Requirement}}{12}$$

If a Transmission Customer requires use of subtransmission facilities, a specific facility use charge will be assessed in addition to this formula rate.

If an existing Transmission Customer elects to retain its Transmission Contract and the contract terms are payment on an energy basis, the capacity-unit rate under the formula rate will be converted to an energy-unit rate based on the individual customer's total load factor.

Rate

The revenue requirement in effect March 1, 2004, through September 30, 2004, is $38,776,237. This revenue requirement is based on FY 2002 data.

[FR Doc. 04–575 Filed 1–9–04; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[OPPT–2003–0073; FRL–7340–4]

Reporting and Recordkeeping for Asbestos Abatement Worker Protection; Request for Comment on Renewal of Information Collection Activities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*) EPA is seeking public comment and information on the following Information Collection Request (ICR): Reporting and Recordkeeping for Asbestos Abatement Worker Protection (EPA ICR No. 1246.09, OMB Control No. 2070–0072). This ICR involves a collection activity that is currently approved and scheduled to expire on July 31, 2004. The information collected under this ICR helps EPA protect public health by establishing workplace standards for state and local government employees who work with asbestos and who are not covered by an Occupational Safety and Health Administration (OSHA)-approved state asbestos plan or state asbestos worker protection plan. The ICR describes the nature of the information collection activity and its expected burden and costs. Before submitting this ICR to the Office of Management and Budget (OMB) for review and approval under the PRA, EPA is soliciting comments on specific aspects of the collection.

DATES: Written comments, identified by the docket ID number OPPT–2003–0073, must be received on or before March 12, 2004.

ADDRESSES: Comments may be submitted electronically, by mail, or through hand delivery/courier. Follow the detailed instructions as provided in Unit I. of the **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: *For general information contact*: Barbara Cunningham, Director, Environmental Assistance Division (7408M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 554–1404; e-mail address: *TSCA-Hotline@epa.gov*.

For technical information contact: Robert Courtnage, National Program Chemicals Division (7404T), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 566–1081; fax number: (202) 566–0473; e-mail address: *courtnage.robert@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are a state or local government employer in a state without an OSHA-approved state asbestos plan or state asbestos worker protection plan that has employees engaged in asbestos-related construction, custodial, and brake and clutch repair activities. Potentially affected entities may include, but are not limited to:

- Public administration (NAICS 92), e.g., State or local government employers.
- Educational services (NAICS 611), e.g., School districts.

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Get Copies of this Document and Other Related Information?

1. *Docket*. EPA has established an official public docket for this action under docket identification (ID) number OPPT–2003–0073. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the EPA Docket Center, Rm. B102-Reading Room, EPA West, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The EPA Docket Center Reading Room telephone number is (202) 566–1744 and the telephone number for the OPPT Docket, which is located in EPA Docket Center, is (202) 566–0280.

2. *Electronic access*.You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr/*.

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified in Unit I.B.1. Once in the system, select ''search,'' then key in the appropriate docket ID number.

Certain types of information will not be placed in the EPA Dockets. Information claimed as CBI and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available