

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation
for Approval to Decrease Electric Rates and
Increase Natural Gas Rates

6690-UR-110

**FINDINGS OF FACT
CONCLUSIONS OF LAW AND ORDER**

On April 1, 1996, Wisconsin Public Service Corporation ("WPS" or "Applicant" or "the Company") filed an application with the Public Service Commission of Wisconsin (Commission) for authority to decrease its rates for electric service and increase its rates for natural gas service. At the same time, WPS prefiled various exhibits and related testimony pertaining to financial and jurisdictional cost information. Additional exhibits and related testimony pertaining to rate information and other required data were filed on May 10, 1996. The Applicant requested a decrease in electric revenues of \$5.0 million and an increase in natural gas revenues of \$7.3 million, based on a 1997 test year, and a requested rate of return of 11.75 percent.

A prehearing conference was held on July 10, 1996, to define the issues and establish a hearing schedule. Pursuant to due notice, hearings were held in Madison before Examiner John Crosetto on October 14-17, 1996.

The parties for purposes of review under ss. 227.47 and 227.53, Stats., are listed in Appendix A. Other persons who appeared are listed in the Commission's files.

A rate decrease in the amount of \$35,514,000 annually from present rates is authorized for Wisconsin retail electric utility operations, an 8.1 percent decrease, and a rate increase of \$5,687,000 annually above present rates is authorized for Wisconsin natural gas operations, a 2.7 percent increase.

Docket 6690-UR-110

Rates are based on an 11.80 percent return on common equity. In addition, a surcharge of \$0.00228 per kWh is authorized for Wisconsin retail electric utility operations until the Kewaunee Nuclear Power Plant (KNPP) is returned to service. Electric rates in the amount of \$10,894,000 for the biennial period are subject to refund depending on the timing of any 1997 mid-cycle shutdown and the 1998 refueling outage at the KNPP, as described in the Findings of Fact.

FINDINGS OF FACT

THE COMMISSION FINDS:

Applicant and Its Business

WPS is a public utility, as defined in s. 196.01(5), Stats., engaged in the production, transmission, distribution, and sale of electricity to approximately 360,000 customers, and in the purchase, distribution, and sale of natural gas to approximately 204,000 customers in northeastern Wisconsin and adjacent parts of upper Michigan. Cities that WPS serves with retail electric energy or natural gas include Green Bay, Oshkosh, Sheboygan, Wausau, Stevens Point, Marinette, and Rhinelander in Wisconsin, and Menominee in Michigan. WPS is an operating subsidiary of WPS Resources Corporation, a holding company based in Green Bay, Wisconsin.

WPS also sells electricity at wholesale rates to numerous utilities and cooperatives for resale. The Federal Energy Regulatory Commission (FERC) regulates these wholesale sales. They are, therefore, not affected by these proceedings. Similarly, the rates applicable to retail sales of electricity and natural gas to Michigan customers are not subject to the jurisdiction of this Commission and are not affected by these proceedings.

WPS obtains the electric energy it needs from various sources. These include several coal-fired plants: Pulliam at Green Bay and the Weston Plant near Wausau, which it owns; the Edgewater No. 4

Docket 6690-UR-110

plant at Sheboygan, which it owns jointly with Wisconsin Power and Light Company (WPL); and Columbia No. 1 and 2 plants near Portage, which it owns jointly with WPL and Madison Gas and Electric Company (MG&E). WPS also obtains electric energy from 15 hydroelectric plants and has a one-third share of the output of the Wisconsin River Power Company. WPS operates four combustion turbine units and one diesel plant. In addition, WPS jointly owns, with Marshfield Electric and Water Department, a combustion turbine in West Marinette. WPS also has connections for purchasing electricity from other utilities and, together with WPL and MG&E, jointly owns the Kewaunee Nuclear Power Plant.

For its gas distribution, WPS contracts for natural gas pipeline capacity from ANR Pipeline Company. WPS purchases natural gas supply from other sources at unregulated rates.

Income Statement

WPS and Commission staff presented testimony and exhibits at the hearings concerning their estimates of the Applicant's 1997 Wisconsin retail electric and gas operations, as well as known and significant events expected to occur in 1998. All parties had the opportunity to cross-examine the witnesses. Significant issues pertaining to the income statements are treated separately below.

Biennial Rate Case Process

In its determination of revenue requirement for the biennial period, Commission staff focused mainly on 1997 financial projections. Staff also considered "known and significant" items forecasted to occur in 1998. These include items that are fairly certain to occur in the second year of the biennial period and that are significant enough in magnitude to materially impact the earnings of the Applicant if they are not reflected in rates. The Commission finds that staff's method of determining revenue

Docket 6690-UR-110

requirement for the biennial period is reasonable.

In its reply brief, WPS asked the Commission to acknowledge that it would prioritize and process a 1998 test year rate case. The Commission determined that, although annual financial projections may be more accurate than the current biennial rate case process, that was not demonstrated on the record and the resources necessary to process annual rate cases are simply not available. In addition, as utilities are asking for less regulation and more opportunity to become competitive, reverting to annual rate cases would not be consistent with that view. Because of many unknowns, the Commission finds it is not reasonable to prioritize a 1998 test year rate case at this time.

New Sales Forecast for Large Commercial and Industrial

The Commission staff's sales forecast includes the Applicant's updates to the forecast for the Large Commercial and Industrial (C&I) class that were provided to staff during its audit. Subsequent to the completion of staff's electric sales forecast, WPS submitted a new sales forecast to staff for the Large C&I customer class. The Commission acknowledged that it is sometimes appropriate to consider information provided after the cutoff date under certain circumstances. Generally, new information is not considered after the cutoff date unless the item is material, is out of the control of the utility, and could not have been known at the time of the audit. The Commission finds that it is not appropriate to include the new sales forecast because it was provided after the cutoff date and it does not meet the criteria for exceptions specified above. Therefore, the staff estimated level of retail electric sales is reasonable. Commissioner Eastman dissents.

Contract With Oconto Rural Electric Cooperative (REC)

In April, 1996, WPS entered into a contract to provide firm power to Oconto REC for ten

years, with Oconto having an option to extend the contract for an additional five years. In its rate filing for this proceeding, WPS treated the projected sales from this contract as opportunity sales. In the calculation of Commission staff's recommended revenue requirement, the contract with Oconto REC was treated as a long-term contract for firm sales. Thus, consistent with prior Commission decisions, fully-allocated costs associated with the sales were assigned to the wholesale jurisdiction. WPS subsequently entered into another contract with a third party, which partially assigned WPS's rights and responsibilities from the original contract to the third party. The Commission finds that the new contract does not release WPS from its responsibilities to Oconto REC and that, even with the existence of the contract with the third party, it is appropriate to assign fully-allocated costs associated with the original contract to the wholesale jurisdiction. Commissioner Eastman dissents.

Loss of WPPI Contract

WPS currently has a contract to provide firm power to Wisconsin Public Power, Inc. (WPPI), a municipal joint action agency, which, in turn, serves the municipalities of Two Rivers, New Holstein, Algoma, Sturgeon Bay, and Eagle River. In October 1997, this contract expires. Sales to WPPI in 1997 are forecasted to be 321,546 MWhs. WPS will sell no firm power to WPPI in 1998.

In its filing, WPS requested that rates for the biennial period be set to recover its estimate of 1998 revenue requirement, which reflects the loss of WPPI. During Commission staff's audit, WPS argued that the loss of this customer should be treated as a "known and significant" event. Staff did not reflect the loss of WPPI in October 1997 as a "known and significant" event because there appeared to be several opportunities during the biennial period for WPS to acquire new wholesale customers, which were not included in staff's sales forecast, to offset the loss of these sales.

The Commission finds it reasonable that the loss of WPPI as a firm, wholesale customer be

Docket 6690-UR-110

treated as a "known and significant" event and that its impact be normalized over both years of the biennial period.

Kewaunee Nuclear Power Plant

KNPP Surcharge

During the refueling outage at the Kewaunee Nuclear Power Plant (KNPP) in the fall of 1996, problems were found with the steam generators which require repairs to be done before the plant can be put back in service. The planned repair is unusual in nature and requires Nuclear Regulatory Commission (NRC) approval. WPS has not yet received NRC approval. Even with approval, there is no guarantee that the repairs will work. Because NRC approval and the success rate of the repairs using a new technology can not be predicted with any certainty, it is reasonable to consider that the KNPP is out of service indefinitely. In order to mitigate the possible financial risk due to the lost availability of the KNPP, WPS asked the Commission to issue an interim order for a surcharge. This surcharge would be designed to recover the incremental purchased power costs incurred to replace the output of the KNPP. WPS's proposal for the surcharge has the rate in effect only during the duration of the current extended KNPP outage. Further, to support such an interim order, WPS requested that the Commission retain jurisdiction in this case limited to the replacement power costs associated with the KNPP outage, during the pendency of that outage, and subject to WPS' agreement to credit customers to the extent that replacement power costs projected due to a KNPP 1997 mid-cycle shut down are effectively not incurred. The Commission determined that it is reasonable to issue an order in this proceeding for a temporary surcharge designed to recover the incremental fuel costs associated with replacing KNPP during the test year. It is also reasonable to base the surcharge on an estimated replacement fuel costs of approximately \$67,000 per day.

The annual estimated replacement fuel costs of about \$24.5 million spread over the estimated test year annual firm sales results in a rate of \$0.00228 per kWh as contained in Appendix D. It is reasonable to apply this amount as a temporary surcharge to all applicable rate schedules for service rendered on and after the effective date of this order until such time that the KNPP is put back into service from the current extended 1996 refueling outage. WPS shall designate the surcharge as a separate item on customer bills for consumer information. An interim order is not required because the temporary surcharge has a specified starting date and termination date.

KNPP Outages

During its audit, Commission staff identified the 1998 refueling outage for KNPP as a "known and significant" event and normalized both fuel costs of \$3,660,000 and non-fuel Operation and Maintenance (O&M) costs of \$3,794,000 associated with it over both years of the biennial period.

Just prior to the hearing in this proceeding, WPS determined that the KNPP steam generators needed to be repaired before the unit could be restarted. The contemplated repairs, using a relatively new laser welding technique, require approval from the NRC. As a condition of its request for approval of the repair technique, WPS assured NRC that KNPP's operating cycle would be limited to 8 to 9 months equivalent full power to allow an early opportunity to inspect the repairs and the other non-repaired steam generator tubes. As a result, if the NRC approves WPS's request and KNPP does restart after these repairs, it is likely that there will be a planned outage in 1997. Consistent with the treatment given to the 1998 refueling outage, staff normalized the estimated fuel costs of \$1,340,000 and non-fuel O&M costs of \$2.1 million associated with the 1997 Kewaunee mid-cycle outage over the biennial period.

As part of its request for a surcharge for KNPP replacement power cost, WPS stated that if KNPP was put back into service so late that the 1997 mid-cycle outage did not occur during the 1997

Docket 6690-UR-110

calendar year, it would refund the associated replacement fuel costs to the extent they are not offset by additional purchased power that could be necessary in the event that KNPP would come back into service at reduced capacity.

The Commission finds that it is reasonable to provide rate recovery for the normalized levels of fuel and non-fuel O&M costs associated with both the 1997 mid-cycle shutdown and the 1998 refueling outage. Revenues amounting to \$10,894,000, made up of \$5,000,000 of fuel costs and \$5,894,000 of non-fuel costs, are subject to refund in the event that one or both of these outages do not occur. In regard to fuel costs, the refund shall be based on the total number of equivalent outage days for the 1997 mid-cycle and 1998 outages occurring during the biennial period, compared to a forecast of 84 days. The determination of the refund shall not consider the additional purchased power costs that may be necessary if KNPP comes back into service at reduced capacity. In regard to non-fuel O&M costs, the refund should be based on the number of outages occurring during the biennial period. If only one outage occurs, one-half of the \$5,894,000 should be refunded. It is likely that refund amounts associated with these outages would not be determined until after the 1998 refueling outage is forecasted to occur.

The Commission finds that WPS shall maintain appropriate records to enable the Commission to determine the necessity of refunds associated with KNPP outages in 1997 and 1998 and to enable refunds to customers, if required and ordered by the Commission.

Depreciation and Decommissioning Expenses

Prior to the Commission decision in this proceeding, the Commission certified new depreciation rates and decommissioning funding levels for KNPP in docket 05-DE-100. That decision determined a service life ending in 2002 to be reasonable for KNPP in the determination of depreciation and

Docket 6690-UR-110

decommissioning expenses. The Commission finds it reasonable that the effective date for WPS to begin recording the new depreciation and decommissioning amounts be the same as the effective date of the order in this proceeding.

It is reasonable to include in test year electric revenue requirement the annuity amounts ordered by the Commission in docket 05-DE-100. WPS's Wisconsin jurisdictional test year income statement includes the Wisconsin jurisdiction's share of retail nuclear plant decommissioning expenses, totalling \$20,807,971. Included in this amount are cash annuity payments of \$14,886,000, which will be paid to a tax-qualified external trust fund for nuclear plant decommissioning, \$1,794,000, which will be paid to a nonqualified external trust fund for nuclear plant decommissioning, and \$4,147,971 from the estimated net earnings on the nonqualified trust fund and the estimated net of tax earnings on the tax-qualified trust fund. Qualified nuclear decommissioning costs are considered to be incurred evenly throughout the year.

The Commission found that no further hearing in this docket is necessary to consider depreciation and decommissioning expenses, as interested parties had an opportunity to be heard on this issue during the October hearings.

Pre-Engineering Costs for Steam Generator Replacement

During Commission staff's audit in this proceeding, WPS filed an application for authority to replace the two steam generators at KNPP. When the Construction Authorization application was filed, the other two co-owners of KNPP did not support WPS's position that the steam generators should be replaced. For that reason, at the time Commission staff's audit was completed, it was uncertain whether staff resources would be devoted to processing the application unless it had the support of all of the co-owners. The WPS filing in this proceeding included \$2.2 million in Construction

Docket 6690-UR-110

Work in Progress (CWIP) for pre-engineering costs associated with the steam generator replacement project. Because of the uncertainty of the project at the time, staff eliminated the amount in CWIP associated with the steam generator replacement project. Subsequent to the completion of staff's audit, a decision was made for staff to begin reviewing the application for authority to replace the steam generators at KNPP. The Commission finds it reasonable, therefore, to include the \$2.2 million of pre-engineering costs associated with the project in the test year. It is also reasonable that the costs included in CWIP for this project be afforded a 50 percent current return.

Pulliam 3 Waterwall Replacement and Turbine Overhaul

In its filing, WPS included \$2.1 million for a waterwall replacement project and a turbine overhaul at its Pulliam 3 generating unit. WPS's Board of Directors placed this unit in long-term layup status in December 1995. Commission staff eliminated the \$2.1 million associated with these maintenance projects from O&M with the understanding that the adjustment could be reversed if WPS could demonstrate at the hearing in this proceeding that the status of the plant had changed and that these maintenance projects would go forward in the test year. WPS did not present any additional information at the hearing regarding the status of the Pulliam 3 unit and did not contest staff's adjustment. The Commission finds staff's adjustment to be reasonable.

New O&M Estimates for Columbia and Edgewater

Several months after the completion of staff's audit in this proceeding, WPS received new 1997 budget estimates for its share of two jointly-owned generating stations, Columbia and Edgewater, from the operating co-owner, WPL. These new budget estimates were provided after the audit was completed in the WPL rate case and were not provided to the Commission staff assigned to that rate case. The new budget estimates, therefore, were not audited by staff. During the hearing in this proceeding, WPS requested that the new budget estimates be included in the final revenue requirement, but it did not provide any of the new budget information for the record. Staff recommended that the new budget amounts not be included because the new estimates were provided after the cutoff date. In addition, the new estimates were not audited by staff assigned to the WPL rate case, nor were they included in that case. The Commission finds that it is not reasonable to include the new budget estimates in final revenue requirement because there is not enough information on the record to do so.

Nonutility Competitive Activities

In its open meeting of February 6, 1996, the Commission approved the Natural Gas and Electric Divisions' plan for addressing small business issues. The plan describes a multiple-pronged approach to addressing these concerns which includes a review of small business issues in the course of the 1996 audits for the rate cases of the five major energy utilities. In this rate proceeding, staff reviewed the activities of WPS that could be considered to be competitive activities, or that could be performed by a nonutility business. In order to complete the audit in a timely manner, this review focused on relatively new activities, as distinguished from activities which may be considered competitive in today's environment, but which have been traditionally performed by utilities. The evaluation of the activities in the latter category is appropriate in the context of restructuring the industry,

Docket 6690-UR-110

but was considered to be beyond the scope of staff's audit in this proceeding.

Based on this review, Commission staff made several adjustments to remove the costs of activities that are not directly related to the provision of gas and electricity, or that could be performed by nonutility businesses in a competitive environment. These adjustments included costs associated with some of the activities in the Applied Technology area, the Communications Development area, and several activities in the Customer Service area. WPS did not contest these adjustments. The Commission finds the staff adjustment to be reasonable.

Commission staff also eliminated costs associated with WPS's plans to physically relocate its transmission staff to an off-site office in an effort to separate the transmission function from the rest of the electric utility. Because no decision has been made on how transmission will be handled in a restructured environment, the Commission finds this expenditure to be premature and not beneficial to ratepayers.

Accounting for Services Provided to UPPCO

In 1996, WPS entered into an agreement with Upper Peninsula Power Company (UPPCO) under which WPS performs the entire system operating function for UPPCO. The Commission finds that this is a utility function whose revenues and fully-allocated costs shall be assigned to the wholesale jurisdiction.

Gas Service Activities

Applicant's gas servicing activities such as furnace and water heater repair, fuel piping installation, furnace inspections, and other miscellaneous activities are accounted for by Applicant as utility-related business. Staff recommended that these activities be accounted for on a non-utility basis

Docket 6690-UR-110

and that all expenses, direct and indirect, be fully allocated. Staff acknowledged that such treatment could be altered, pending the outcome of the recently initiated docket 05-BU-101 related to affiliated interest transactions. The staff recommendation was not contested by Applicant.

The Commission finds that Applicant's gas servicing activities, as described above, should be accounted for as non-utility activity, on a fully-allocated basis, including all direct and indirect costs. Such treatment may be altered, pending the outcome in docket 05-BU-101.

Accounting Treatment of Conservation Expenditures

In its filing in this proceeding, WPS proposed eliminating the practice of "capitalizing," or deferring, conservation investments such as rebates, direct loans, and interest buy-downs. Wisconsin Electric Power Company (WEPCO) and Northern States Power Company (NSP) have already discontinued deferral accounting for conservation investments and WPL never adopted deferral accounting for conservation investments. It is appropriate for these expenditures to be accounted for on a consistent basis among the utilities in this state as the industry moves toward a more competitive environment. The Commission finds it reasonable for WPS to discontinue deferral accounting for conservation investments beginning in 1997. The Commission also finds it reasonable to amortize the estimated unamortized conservation investment as of December 31, 1996, over a five-year period.

Annual conservation and weatherization expenditures of \$5,338,000 for electric operations and \$4,209,000 for gas operations are reasonable for each year of the biennial period. All of these expenditures shall be escrowed.

The estimated underspent escrow amounts at the end of 1996 are \$4 million for the electric utility and \$3 million for the gas utility. These underspent amounts should be returned to ratepayers over the biennial period at a rate of \$2 million per year for the electric utility and \$1.5 million per year for the

Docket 6690-UR-110

gas utility. The annual escrowed conservation costs recoverable in rates for each year of the biennial period are \$3,338,000 for electric operations (\$5,338,000 authorized expenditures less \$2,000,000 underspending amortization) and \$2,709,000 for gas operations (\$4,209,000 authorized expenditures less \$1,500,000 underspending amortization).

In addition, the annual amortization of the remaining deferred conservation investments shall be \$5,500,000 for electric operations and \$2,000,000 for gas operations. These amortizations shall be charged to nonescrowed customer service expense in each year of the biennial period.

Advertising

Advertising expenses allowed in rates consist of expenses for conservation and safety advertisements, advertisements required by law or Commission directive, such as notification of rate increase requests, and informational advertisements that directly and substantially benefit the ratepayer. The Commission finds approved advertising expenses total \$2,123,000, of which approximately \$2,049,000 are allowed in Wisconsin retail rates. Exclusion of all other advertising expenses is just and reasonable.

After excluding these other expenses, the advertising budget constitutes 0.3 percent of the total revenue requirement. Approximately 26 percent of this amount pertains to conservation.

Post-Retirement Medical Expense

In December of 1995, WPS lowered its actuarial assumption called the medical trend rate, which is used in determining the annual post-retirement medical expense. This resulted in 1996 post-retirement medical expense being significantly lower than the amount forecast in the last rate order for this item. Staff decreased the Company's estimate of 1997 post-retirement medical expense by the

Docket 6690-UR-110

amount that the expense was lowered in 1996 because of the change in the medical trend rate which was portrayed to staff as a change to enhanced earnings. It was staff's position that, unless the adjustment was made, WPS ratepayers would pay twice for that portion of the expense that was collected in rates in 1996 but not recognized as expense because of the change in assumption.

WPS argued that the change in assumption was proper and that the resulting variance was the same as any other estimate that varies from actual in a forward-looking test year. The Commission determined that the adjustment was reasonable based on trended information and was not inconsistent with Generally Accepted Accounting Principles and that no adjustment was necessary to WPS's estimate of post-retirement medical expense.

Manufactured Gas Production Site (MGP) Clean-up

Applicant, in its initial filing, did not include any dollars in revenue requirement for MGP clean-up. In supplemental testimony, Applicant proposed an amortization level that included estimated future expenditures. In later testimony, Applicant proposed that nothing be included in the 1997 test year revenue requirement and that this issue be addressed in a later rate case.

In docket 6680-UR-108, WPL's application for authority to increase electric, water and natural gas rates, the Commission found that a sharing of MGP costs between ratepayers and shareholders was reasonable. The sharing would be achieved by means of deferred accounting with recovery of the amortization level by ratepayers, but with no recovery in rates of the carrying costs on the unamortized balance of the deferral account. In addition, in docket 6680-UR-108, the Commission determined that the use of deferred accounting would allow actual costs to be reviewed before inclusion in rates and recovery from ratepayers. MGP costs were treated similarly by Commission staff in this case. Staff included approximately \$225,000 in revenue requirement to begin the initial amortization of allowable MGP costs that had been previously deferred. Staff did not include the unamortized balance of the deferral account in working capital, per the above Commission policy.

The Commission finds that the staff treatment that begins the initial amortization of MGP costs that had been previously deferred to be reasonable. The Commission also finds that the unamortized balance of the deferral account may not be included in working capital.

Contract with the Oneida Nation

In 1996, WPS entered into an agreement with the Oneida Nation to provide emergency backup generation for its Oneida Bingo and Casino Complex (Oneida) as part of a two-year pilot. The diesel generators providing this backup generation employ a new technology that allows them to either be dedicated to Oneida or used as system peaking power. Although the generators are physically located on Oneida land, they are owned, operated, and maintained by WPS. After two years, the Oneida Nation has the option to purchase the generators from WPS.

Commission staff eliminated this investment from net investment rate base because staff considered this investment to be nonutility in nature. Staff determined that the primary purpose of the generators was to provide emergency backup generation for Oneida. As such, the investment would not be properly included in net investment rate base because it would not be dedicated to utility service.

WPS stated that the generator investment should be included in rate base because the provision of backup generation was only incidental and that the primary purpose of the generators was to provide system peaking power which benefits all of WPS's system.

The Commission finds that it is reasonable to include these generators in net investment rate base as utility property. Chairman Parrino dissents.

Area Expansion Program Surcharges

Surcharges related to WPS's Area Expansion Program (AEP) are applied by WPS when natural gas service to an area, either within its existing franchise area or in a new area, requires an additional contribution to meet cost-effectiveness standards. These surcharges, collected from customers living in the AEP areas, are reductions to the cost of construction from the customers served by the AEP extension. Commission staff, during the course of the audit, incorporated correcting entries

Docket 6690-UR-110

to reflect AEP surcharges as reductions to the cost of construction. WPS had been accounting for AEP surcharges as sales revenues.

The Commission finds that AEP surcharges, both past and future, should be properly reflected as reductions to the cost of construction and that staff's correcting entries did not result in retroactive rate-making. The adjustments are necessary to appropriately reflect rate base and are necessary for compliance with the Uniform System of Accounts.

Electric Opportunity Sales

Staff accepted WPS's filed opportunity sales estimates. In determining the reasonableness of WPS's estimates, staff reviewed recent historical sales levels along with considering the effects of the Commission's policy for determining opportunity sales classification, the nature of the types of economic transactions that occur as opportunity sales, and the ability of WPS to participate in these transactions based on its relative cost to generate and the evolving power market. WPS said the accepted opportunity sales estimates were too high. WPS said that staff's review did not consider that some of the sales reflected in WPS's original estimate of opportunity sales were under negotiation at the time of preparing the estimates. Some of these potential sales have since been lost to competitors. Others have been entered into. Staff reclassified those sales as long-term sales which should be fully allocated without a corresponding reduction to the opportunity sales estimate. WPS also stated that the potential unavailability of the KNPP for all or part of the test year would limit its ability to make opportunity sales.

The Commission determined that it is reasonable to reduce the WPS filed estimate of opportunity sales by 125,000 MWh resulting in an approximate \$143,000 increase in net monitored fuel costs. Chairman Parrino dissents.

Decontamination and Decommissioning

The Commission determined that rate recovery of WPS's payment for the Department of Energy's (DOE) Decontamination and Decommissioning (D&D) special assessment is not reasonable in this test year. This results in about a \$591,000 reduction in test year fuel costs. The Commission finds it reasonable that WPS collect customer billing information for the purpose of reimbursing its ratepayers in the event WPS receives a refund or some form of credit from the DOE for the D&D assessments.

The D&D assessments were levied to finance the cleanup of facilities that DOE used before 1992 for enriching uranium compounds. The Energy Policy Act of 1992 (EPACT) authorized the collection of these fees, allocated between utilities based on the relative amount of DOE's separative work units (SWUs) used in building the fuel burned at nuclear reactors prior to 1992. The estimated costs of cleanup were allocated over a 15-year period and are being collected annually before the first of November, based on the federal fiscal year, October to September.

The charge for D&D first appeared in the WPS rate case in docket 6690-UR-107, for the 1993 test year. At that time, the Commission allowed WPS to recover an estimate of the D&D fees for the test year. Through November 1995, WPS has paid to DOE approximately \$5,067,213 for the D&D assessments.

On June 22, 1995, the U.S. Court of Federal Claims ruled in Yankee Atomic Electric Company v. The United States, 33 Cl. Ct. 580 (1995), that the D&D assessments were unlawful. DOE had written fixed charge contracts, which each utility contracting for the enrichment services had signed. According to the Court of Claims, the additional charge authorized in the EPACT for the D&D assessment is contrary to the original contract language.

These contracts use a standard format. WPS's contract is similar or identical to the contract under review with Yankee Atomic. As a result, it is reasonable to assume that WPS's assessments are

Docket 6690-UR-110

also unlawful and WPS ratepayers should not be asked to fund these assessments. Although WPS declared its intent to forward any refunds it may receive to ratepayers, questions of intergenerational equity and the difficulty of refunding these amounts to the same ratepayers who originally paid the assessments arise.

The Commission expects that eventually the DOE will refund the D&D assessments paid by the affected utilities by either establishing a payment schedule or offsetting other DOE billings. Should that happen, WPS should file a plan of refund for the D&D assessments previously collected in its rates, using the database of customer billing information earlier described.

Eliminating the D&D assessment from the test year fuel costs reflects an aggressive tax position. In keeping with its policy of supporting utilities in aggressive tax stances, the Commission considers it appropriate that WPS be reimbursed if the Yankee Atomic decision is overturned, modified or is otherwise held not to apply. Commissioner Eastman dissents.

New Rail Contract

Subsequent to its audit in this case, staff learned that WPS had entered into a new contract with a rail carrier which materially reduced the cost of transporting coal to some WPS power plants. WPS provided information which showed that the resulting fuel costs would be lower than its filed estimates by about \$2.7 million for 1997 and \$5.0 million for 1998. The Commission determined that it is reasonable to normalize the effects of the new rail contract and reduce the test year revenue requirement by approximately \$3,841,000.

Monitoring of Fuel Costs

The Commission finds that the resulting reasonable test year fuel costs is \$131,424,000 reflecting the cost of generation, purchased energy, wheeling, and capacity less the revenue from opportunity sales of energy and capacity. The test year fuel cost divided by the test year estimate of net native energy requirements of 11,381,855 MWh results in an average net fuel cost per kWh of \$0.01155. The test year fuel costs represents a normal level of fuel costs for the biennial period which reflects the average of the estimates for 1997 and 1998 in Appendix D.

For purposes of monitoring WPS's fuel costs pursuant to s. PSC 116.04, Wis. Adm. Code, the Commission finds that the following variance ranges are reasonable for the Applicant's fuel costs: 1) for the annual range, plus or minus 2 percent; 2) for the monthly range, plus or minus 8 percent; and 3) for the cumulative range, plus or minus 8 percent for the first month of the test year, plus or minus 5 percent for the second month of the test year and plus or minus 2 percent for the remaining months of the test year and until the next rate order. It is reasonable that the method of application of those ranges, established in prior Commission decisions for WPS, continue to be utilized. The Commission finds it reasonable to use the data in Appendix D for monitoring these ranges. The monthly fuel cost estimates

Docket 6690-UR-110

for 1997 and 1998 in Appendix D do not include the interim surcharge for the KNPP replacement fuel costs. For those days when the surcharge is in effect, the estimated fuel costs monitored should include an additional \$67,000 per day.

Deferral of Buyout Costs of the NERCO and Soo Line Contracts

In docket 6690-UR-106, the Commission allowed WPS to defer costs associated with the modification of contracts to purchase and transport coal from the NERCO Coal Company. In order for WPS to recover those deferred costs in rates, the Commission required WPS to provide a cost/benefit analysis during each rate case.

Staff has reviewed the Company's calculation of a cost/benefit analysis in the last three rate cases. When the net benefits from 1994 and 1995, verified by staff in this case, are added to the previous years' net benefits, the cumulative net benefit total about \$45,141,634.

Because the amortization of the buyout deferrals lasts through 1996, WPS would be required to prepare a cost/benefit analysis in its next rate case under the Commission's order in docket 6690-UR-106. Recognizing that the net benefits accumulated through 1995 are considerably larger than the costs of the buyouts, the Commission determined that no further analysis of the net benefits of the NERCO related buyouts is necessary.

Summary

Income Statement

In addition to the findings regarding the specific items discussed above, all other Commission staff estimates and adjustments to the Applicant's estimate are reasonable and just. Accordingly, estimates of 1997 Wisconsin retail electric and gas operations that are considered reasonable and just for purposes of determining the revenue requirement in this proceeding are as follows:

1997 Test Year

Wisconsin Jurisdictional Income Statement

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Operating Revenues		
Sales of Electricity	\$439,928	
Sales of Gas & Transportation		\$211,371
Other Operating Revenues	<u>15,228</u>	<u>964</u>
Total Operating Revenues	\$455,156	\$212,335
Operating Expenses		
Power Production Expenses	\$173,262	
Purchased Gas Expense		151,784
Transmission & Distribution Expenses	32,794	14,224
Customer Accounts Expenses	12,530	6,172
Customer Services Expenses	13,047	7,202
Sales Expense		
Administrative & General Expenses	<u>26,023</u>	<u>7,168</u>
Total Operation & Maintenance Expenses	\$257,656	\$186,550
Depreciation Expense	65,679	7,363
Taxes Other Than Income Taxes	20,962	3,873
Income Taxes	36,414	3,900
Investment Tax Credit-Restored	<u>(1,489)</u>	<u>(135)</u>
Total Operating Expenses	\$379,222	\$201,551
Net Operating Income	75,934	10,784
Adjustment to Net Operating Income	<u>5,330</u>	
Adjusted Net Operating Income	<u>\$81,264</u>	<u>\$10,784</u>

Net Investment Rate Base

It is appropriate to utilize the Commission staff-filed average net investment rate base adjusted to include the investment in the generators located on property owned by the Oneida Nation and for the jurisdictional impact of all adjustments subsequent to the preparation of the staff exhibit. For purposes

Docket 6690-UR-110

of determining the revenue requirement in this proceeding, a reasonable and just estimate of WPS's test year average net investment rate base for Applicant's Wisconsin retail electric and gas operations is as follows:

1997 Test Year

Wisconsin Jurisdictional Net Investment Rate Base

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Utility Plant in Service	\$1,365,611	\$239,391
Less: Accumulated Depreciation	<u>924,494</u>	<u>120,476</u>
Net Utility Plant in Service	\$ 441,117	\$118,915
Add: Nuclear Fuel Investment-net	14,387	
Gas Stored Underground		10,957
Materials and Supplies-Fuel	8,618	
Materials and Supplies-Other	15,466	2,488
Decommissioning Trust	89,798	
Soo Line Rail Contracts-net	1,449	
Investment in WVIC-net	426	
Tomahawk Pulp & Paper	656	
Less: Customer Advances-net	11,528	1,407
Amortization Reserve-Federal	<u>890</u>	
Average Net Investment Rate Base	<u>\$ 559,499</u>	<u>\$130,953</u>

Pro Forma Rate of Return

Estimated operating income for test year 1997 Wisconsin retail electric and gas utility operations at present rates would result in the following rates of return on respective test year average net investment rate base:

Electric	Gas
----------	-----

	(000's)	(000's)
Adjusted Operating Income	\$ 81,264	\$ 10,784
Average Net Investment Rate Base	559,499	130,953
Earned Rate of Return	14.52%	8.24%

Inflation Rates

The Commission finds that a reasonable inflation rate estimate for 1997 and 1998 is 3.0 percent per year.

Capital Structure

As in prior rate cases, the Commission has determined that the average amount of the leveraged Employee Stock Ownership Plan (ESOP) (\$16,346,000 for 1997) should be included when determining appropriate debt and equity levels for WPS, but not in setting utility rates.

In this rate case, staff agreed with WPS's criticism that the long-standing Commission policy of requiring 47 to 52 percent common equity, on a financial basis, in the WPS capital structure was now inappropriate due to increased business and financial risk associated with industry restructuring developments, the signing of an independent power contract, and the pending mergers of various midwestern utilities. Staff and WPS were in agreement that the new common equity guideline, on a financial basis, should now be one requiring 47 to 54 percent common equity. Such an equity range is consistent with bond rating agency guidelines to maintain a "AA" rating on WPS's long-term debt. Allowing more common equity in the capital structure does increase the weighted cost of capital; however, the cost increase is a reasonable one for ratepayers to bear given the indicated increases in risk.

When consideration is given to the ESOP in the test year, the utility financial capital structure consists of 53.70 percent common stock equity, 6.32 percent preferred stock, 37.99 percent long-term

Docket 6690-UR-110

debt and debt equivalents, and 1.99 percent short-term debt. The 53.69 percent common equity, on a financial basis, also falls within the newly adopted common equity guideline.

The Commission determined that a reasonable utility capital structure for setting rates consists of 54.80 percent common stock equity, 6.45 percent preferred stock, 36.72 percent long-term debt, and 2.03 percent short-term debt.

The Commission finds the indicated ratemaking and financial capital structures reasonable. The Commission is also aware that a reasonable utility capital structure is not static and may change as the utility's situation and financial conditions change. Consequently, the appropriate utility capital structure will be reviewed periodically.

Cost of Capital

Applicant, in its initial filing, proposed an 11.75 percent return on equity. At hearing in this proceeding, WPS requested that a range spanning 11.75 to 12.25 percent should be considered to reflect both increased business risk as well as its superior utility management.

Staff presented initial testimony which concluded that a 11.10 percent return on common stock equity would be a reasonable return on equity. At the technical hearing, staff indicated that changes in capital costs suggested that a 11.20 percent return on common equity would be more appropriate. Staff, in its testimony, did not support WPS's request to increase its return on equity for superior management because shareholders already receive compensation via higher stock prices associated with superior management. Staff did not support increasing the return to reflect increases in business risk, because staff already supported the Company's request to increase the amount of allowed common equity in the capital structure as a way to compensate for increases in risk.

The Commission, in its determination of a fair return on common stock equity, must strike a

Docket 6690-UR-110

balance between the investor and customer. It would be undesirable to allow a return on equity so high as to be excessive, just as it would be undesirable to allow a return so low as to discourage investors. The authorized return on common stock equity should be commensurate with the earnings of other business enterprises that have similar risks, maintain the financial integrity of the utility, attract and hold capital at reasonable costs, and protect the interests of utility consumers.

In view of these considerations, the Commission considers a 11.80 percent return on common stock equity to be reasonable and just in this proceeding. Chairman Parrino dissents, indicating that a 11.50 percent return on equity would be reasonable. In choosing the return on equity, the Commission considered WPS's managerial performance.

The Commission found that the appropriate cost of short-term debt is 5.40 percent. Commissioner Eastman dissents, indicating that a 6.00 percent short-term debt rate would be reasonable. Because no new long-term debt was planned in the test year, no estimate of a reasonable long-term debt cost for a new issue was necessary.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates in the 1997 test year are as follows:

RATEMAKING CAPITAL STRUCTURE

	Dollar Amount (000's)	Capital- ization Ratios percent	Annual Cost Rate percent	Weighted Cost Rate percent
Utility Common Equity	434,773	54.80%	11.80%	6.47%
Preferred Stock	51,200	6.45	6.08	.39
Long-Term Debt	291,286	36.72	7.47	2.74
Short-Term Debt	<u>16,120</u>	<u>2.03</u>	5.40	<u>.11</u>
Total Utility Capital	<u><u>793,379</u></u>	<u><u>100.00%</u></u>		<u><u>9.71%</u></u>

The weighted cost of capital of 9.71 percent is reasonable for WPS in the 1997 test year. This capital structure and weighted cost of capital produces an economic cost of capital of 14.31 percent and a pre-tax times interest coverage ratio of 5.02 times.

Construction Work in Progress (CWIP)

This issue was not contested. The present policy which is to be continued is that a current return on 50 percent of forecasted average CWIP is appropriate. The 50 percent of average CWIP which does not earn a current return may accrue an allowance for funds used during construction (AFUDC) at the adjusted weighted cost of capital of 10.37 percent.

Dividend Restriction

This issue was not contested, and all prior restrictions remain in force.

Ten-Year Financial Forecast

The Commission finds that Applicant's ten-year financial forecast is useful and should be submitted in future rate cases.

Rate of Return on Rate Base

It is appropriate and necessary that the composite cost of capital rate, 9.71 percent, be translated into a rate of return to be applied to the average net investment rate base for the computation of the overall return requirement in dollars.

The estimate of the Applicant's average net investment rate base plus construction work in progress and conservation investments for the 1997 test year is 93.67 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate adjustments. This is a reasonable and just factor for use in translating the cost of capital into a return requirement applicable to the average net investment rate base.

As discussed earlier, it is reasonable that 50 percent of the average CWIP and the entire average capitalized conservation investment should be allowed a current return. To provide a current return on these items, two adjustments to the return on rate base are necessary. These adjustments are reflected in the following return requirement:

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Cost of Capital	9.71%	9.71%
Average Percent of Utility Net Investment Rate Base Plus Construction Work in Progress and Conservation Investments to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credits	93.67%	93.67%
Percent Return Requirement Applicable to Net Investment Rate Base	10.37%	10.37%
Adjustment to Return Requirement on Net Investment Rate Base to Provide a Current Return on 50 percent of the Average Test Year CWIP	.08%	.07%
Adjustment to Return Requirement on Net Investment Rate Base to Provide a Current Return on Capitalized Conservation Investments	.27%	.40%
Adjusted Percent Return Requirement on Net Investment Rate Base	10.72%	10.84%

Revenue Requirement

On the basis of the findings in this order, a \$35,514,000 decrease in Wisconsin retail electric revenues and a \$5,687,000 increase in Wisconsin natural gas revenues is reasonable and just. The indicated rate revisions are computed as follows:

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Return Earned on Average Net Investment Rate Base at Present Rates	14.52%	8.24%
Required Return on Average Net Investment Rate Base	10.72%	10.84%
Average Net Investment Rate Base (000's)	\$559,499	\$130,953
Amount of Earnings Deficiency (Excess) on Average		

Docket 6690-UR-110

Net Investment Rate Base (000's)	(\$21,261)	\$3,405
Revenue Deficiency (Excess) to Provide for Earnings Deficiency (Excess) Plus Federal and State Income Taxes at a Combined Rate of 40.135% (000's)	(\$35,514)	\$5,687

Natural Gas Sales Promotion

Applicant proposed a natural gas sales promotion budget of \$1,322,637 for the 1997 test year. Commission staff responded by proposing that Applicant submit documentation to justify these costs in rates as required by dockets 05-GI-101 and 05-UI-103. Staff indicated that several changes in current and future regulation of the gas industry merited this level of scrutiny, including an increasing emphasis on effective competition in gas commodity markets and heightened sensitivity to small business concerns.

Applicant submitted no documentation to justify the proposed budget. Instead of trying to justify these costs, Applicant proposed to shift them to the Area Expansion Plan (AEP) surcharge. This surcharge is the product of calculations embedded in the expansion model used by staff to evaluate construction of gas main extension in new service territory. If marketing and promotion costs are not reasonable as part of the capital expenditure for construction of new main, these costs must be recovered directly from new customers benefiting from this extension of service.

The Commission finds that a gas sales promotion budget of zero dollars for the 1997 test year is reasonable and that shifting gas sales promotion budgets to the AEP surcharge does not eliminate the requirement to justify these costs. The Commission finds that no proposed gas sales promotion budgets are reasonable until they are justified as required by dockets 05-GI-101 and 05-UI-103. Zero-based budgeting for gas sales promotion is appropriate in all future rate cases unless compelling justification is provided by Applicant.

Demand-side Management

Electric DSM Goals

The Commission finds Commission staff's proposed total Company electric demand side management (DSM) goal of 94.6 GWh and low-income goal of 1.55 GWh to be reasonable. These goals are appropriate goals for WPS for each of 1997 and 1998. Establishing these goal levels is consistent with the Commission's recent electric industry restructuring directions and with the Advance Plan 7 (05-EP-7) decision on maintaining flat DSM goals in the restructuring transition period. Commissioner Eastman dissents with respect to the total Company DSM goal.

Natural Gas DSM Goals

The Commission finds Commission staff's proposed total Company natural gas DSM goal of 4.483 million therms and low-income goal of 481,000 therms to be reasonable. These goals are appropriate for WPS for each of 1997 and 1998. The Commission also establishes sector therm targets as follows:

<u>Sector</u>	<u>Annual Therms</u>
Residential	1,294,250
Commercial	1,085,000
Industrial	472,000
Rental	450,750
Transportation	700,000

Commissioner Eastman dissents on establishing sector targets.

Residential Electric DSM

It has been the Commission's intent to allow utilities some flexibility in which sectors it finds the DSM savings to meet Commission DSM goals. This is why the Commission recently stopped its

Docket 6690-UR-110

practice of setting electric DSM sector goals for WPS and other utilities. This does not mean, however, that the Commission is no longer concerned about the adequacy of and equity of the DSM services offered to different customer sectors. The Commission finds that the recent performance and trends in performance of WPS in delivering conservation services to the residential electric customer sector is cause for concern. Commission staff asked the Commission to consider several options for action to provide incentive for WPS to improve its performance in this sector. The Commission finds, that of the options considered, it is most appropriate to re-establish annual residential electric energy savings goals for WPS.

A residential electric DSM energy goal of 24.1 annual GWh is reasonable and appropriate for WPS for each of the years 1997 and 1998. This is the level of residential electric goal set by the Commission for WPS for 1994, and the level advocated by Commission staff for 1995. Commissioner Eastman dissented.

Competitive Acquisition of DSM

It is a goal of this Commission to develop a sustainable and competitive DSM infrastructure and marketplace. The Commission expects that eventually all customers will pay for all of the DSM services they receive. Currently, however, the market is not capable of delivering all of the DSM that is appropriate under good public policy. The DSM market is in its infancy and needs help in the transition to a sustainable infrastructure. It is in the public interest for the Commission to ensure that such help is given.

In the past, regulated DSM services were largely ratepayer funded and programs were primarily delivered, designed, and controlled by monopoly utilities. Utilities were expected to achieve DSM savings and were measured against Commission goals. Utility involvement and expenses were accounted for above-the-line as utility services.

The goal of the Commission is to achieve, within a few years, a state where all DSM programs are funded through alternate sources and delivered through competitive processes. Programs may be designed, for a period, under the authority of a Public Benefits Board. Utilities would have no Commission goals and involvement by utilities in DSM services, if any, would be below-the-line.

During the transition, promotion of DSM should continue to be ratepayer funded, competitive acquisition of services should increase, and utility goals will continue. To facilitate this transition, WPS should develop a comprehensive, two-year plan covering the provision of energy efficiency services in 1997 and 1998. The plan should describe how WPS intends to reach a state, by the end of 1998, where all ratepayer-funded energy efficiency efforts towards meeting the Commission's DSM policy goals are provided by third-party providers. The plan should also reflect that, by the beginning of 1999, all customer DSM services that WPS continues to provide be accounted for below-the-line.

The objectives of the plan should include and be consistent with: 1) developing a sustainable

Docket 6690-UR-110

DSM infrastructure; 2) facilitating the transition to the Public Benefits Board; 3) promoting fair competition; and 4) seeing that DSM is delivered by entities with proper incentive to provide it. The plan should also be consistent with current Commission DSM policies. These policies include, in addition to those listed above, the maintenance of historical levels of energy savings in the transition period.

The plan should contain proposals for the extent of bidding by sector and for the various aspects of the DSM programs, including design, delivery, and administration. Any competitive acquisition processes proposed should have an independent evaluator, if WPS intends to be a bidder. WPS should work with Commission DSM staff to develop an outline and framework for the plan, prior to drafting. The framework should establish the goals and scope of the transition plan. The plan should be submitted within 120 days of the date of this order.

Conservation Escrow

WPS proposed to include \$192,000 dollars in the conservation escrow for technology assessment of electric vehicles, photovoltaics, and fuel cells. The Commission finds that, as described, these activities are not conservation, and the expenses, therefore, are not appropriate for conservation escrow coverage. These research and development expenditures are appropriate utility expenses, however, and are reasonable to include in the revenue requirement.

Electric Rates

The present electric rates are unreasonable because they will produce excessive revenues in the test year. Authorized rates and rules, shown in Appendix B, will provide a decrease in annual Wisconsin retail electric revenues of \$35,514,000.

Electric Cost-of-Service Studies

The fully-allocated embedded cost-of-service studies presented in this proceeding allocated those costs which are under the jurisdiction of this Commission to the respective customer classes. WPS presented one embedded cost-of-service study that allocated generation and transmission plant on coincident peak demands net of interruptible loads, and distribution plant on both noncoincident demands and customer counts. WPS disputed the staff's Location cost-of-service study, which allocated 100% of distribution costs based on non-coincident peak demand.

Staff submitted three embedded cost-of-service studies. One staff embedded study was designed to replicate WPS's embedded study, adjusted to reflect staff's proposed adjustments to rate base, expenses, sales, and revenue requirement. This study was performed to demonstrate the effect of the staff adjustments on cost-of-service and to provide a starting point to examine the sensitivity of allocation changes made in staff's other two embedded studies. The staff's Time-of-Day (TOD) cost-of-service study is a refinement of the allocation approach used by WPS. Both studies use the minimum system approach to allocate the customer distribution costs. Unlike WPS's study, the TOD study allocates generation costs on the basis of both demand and energy. Another major difference in the TOD study is that the allocation process reflects energy-related costs based on each class's on-peak and off-peak energy usage. The staff's Location study was performed in a manner similar to the TOD study except that distribution expenses were allocated primarily on the basis of class non-coincident demands rather than upon a minimum system method. The Location study thus provides an appropriate range of distribution cost allocations.

The Wisconsin Industrial Energy Group (WIEG) preferred the staff's Company Adjusted cost-of-service study when allocating revenues.

The Commission recognizes that embedded cost-of-service studies are not precise reflections of

Docket 6690-UR-110

cost causality, but rather are heavily dependent on the accuracy of the data used and on the many judgments of the analysts performing the studies. The Commission does not adopt any single set of assumptions for cost-of-service studies or any particular cost-of-service method. Rather, it is appropriate that all of the cost studies presented in this proceeding be considered in determining class cost responsibility, because no single study is accurate enough to establish the precise cost of providing electric service to any class. All of the studies provide useful information based upon differing points of view. The cost studies that have been presented, as a group, provide a balanced embedded cost range for the Commission to consider in establishing class revenue responsibility in this proceeding.

Electric Class Revenue Allocations

Revenue allocations were proposed by WPS, Commission staff, WIEG and the Wisconsin Paper Council (WPC). Selection of final class revenue targets, using the cost-of-service studies and the existing rate structures as guidelines, and adhering to the general principles of ratemaking, is largely a matter of judgment. Based upon the record in this proceeding, the Commission finds that the revenue allocation proposed by the staff, adjusted for the rate design changes and the final revenue requirement approved in this order, to be reasonable and just.

The total Wisconsin retail electric revenue decrease of 8.1 percent will result in average class revenue decreases as shown in Appendix B. The decreases are reasonable and just.

Electric Rate Design

Both WPS and the Commission staff presented rate design proposals in this proceeding. WIEG also presented rate design proposals for the industrial class.

Class I and II Rate Territories

Commission staff proposed eliminating the difference in rate classification based upon Class I and II territories and to combine the farm rate class with the small commercial and industrial classes. Staff indicated that all other investor-owned utilities within the state had eliminated this rate differential and that the difference in meter reading costs was minimal. WPS proposed maintaining the current Class I and II rate territories and the farm rate classification. WPS supported its proposal on the basis of customer density and meter reading costs. The Commission finds that it is reasonable and just to maintain the current rate territories for all classes except the small commercial and industrial (TOD). The small commercial and industrial (TOD) customers are divided into Cg-1 and Cg-2 rate classes, but for many years the rates for these two customer classes have been the same. Combining the small commercial and industrial (TOD) customers into one class will consolidate these similar customers into one tariff. The Commission finds that it is reasonable and just to combine the small commercial and industrial (TOD) Cg-1 and Cg-2 into one class called small commercial and industrial (TOD), Cg-1. Chairman Parrino dissents on the decision not to combine the farm rate class with the small commercial and industrial classes.

Small Customer Energy Rates

WPS proposed a smaller overall decrease in electric rates than proposed by staff for the small customer energy rates. It proposed an approximate 1.5 percent decrease to time-of-day energy charges and an approximate 4 percent decrease in other energy charges for the small customer energy rates. WPS proposed \$1.50 to \$2.50 increases in customer charges for most of the small customer rate classes. The decrease in energy charges and increases in customer charges limited the overall decrease to these classes to approximately 0.05 percent for residential customers and approximately

Docket 6690-UR-110

2.25 percent for other small customer rate classes.

Commission staff proposed decreases in the energy rates for the residential and farm customers, continuing the equivalent energy charges for these classes. The Commission authorized energy rates in the last rate case, Docket 6690-UR-109, for the small commercial customers (<100 kW) that set them equivalent to the energy charges of the residential and farm customers. Staff proposed decreases in the small commercial (<100 kW) energy charges equivalent to the residential and farm customers proposed rates. Staff proposed customer charges that reflected its proposal to combine the Class I and II rate territories.

The staff revised rate design follows the current classifications for small customer energy rates and has been adjusted to meet the final revenue requirement. The Commission finds the revised rate design for the small customer rate classes to be appropriate and reasonable.

Water Heater Shedding Credit

WPS proposed to lower the monthly credit from \$3.00 per month to \$2.00 per month for shedding water heaters under the Rg-DC and Cg-DC riders. This reduction more closely reflects the value of the avoided capacity needs of the Company. The Commission finds WPS's proposal to lower the monthly credit to \$2.00 per month to be reasonable and just.

Small Commercial & Industrial (>100 kW) Demand and Energy Charges

WPS submitted a proposed rate design for demand-metered small commercial and industrial classes that decreased the energy charges. Demand charges were proposed to be unchanged except for the small commercial and industrial time-of-day demand rate, which was increased by \$0.60. Customer charge increases were also proposed for these small commercial and industrial rate classes.

Docket 6690-UR-110

WPS also proposed to provide, on an optional basis, the opportunity for customers whose demand is between 100 and 200 kW to take service under the Cg-1 or Cg-2 time-of-use rate schedules. These customers do not currently have service available to them under an optional time-of-use rate.

Commission staff submitted a rate design that decreased the energy charges for these rate classes and decreased the demand charges for the urban and rural small commercial and industrial (>100 kW) rate classes. Staff proposed a decrease for the energy charges for the small commercial and industrial time-of-day rate class and an increase in the demand charge of \$0.10. Staff's design was based on staff cost-of-service information and upon comparisons with other major Wisconsin electric utility rate structures. Staff supported WPS's proposal to offer customers with demands between 100 kW and 200 kW the option to be served on the newly combined Cg-1TOU rate schedule.

The staff's rate design was revised to meet the established revenue requirement. The Commission finds staff's revised rate design for the demand-metered small commercial and industrial rate classes to be reasonable and just. The Commission finds it appropriate to open the Cg-1TOU rate schedule to customers with demands between 100 and 200 kW on an optional basis to be reasonable and just.

Large Commercial and Industrial Energy and Demand Charges

WPS, WIEG, WPC and Commission staff all made proposals for the Cp-1 and Cp-2 rate design. WPS's and WIEG's rate design reduced on-peak and off-peak energy charges to the average five-year marginal energy costs. WPS proposed that peak and intermediate demand charges be increased based on its proposed revenue requirement. WIEG proposed decreasing these demand charges by equivalent amounts to reach the final revenue requirement. WPC did not propose specific rates, but supports rates that are cost-based and subsidy-free for all of the utility's customers. Staff

Docket 6690-UR-110

proposed lowering the on-peak energy charge and maintaining the off-peak energy charge at its current level. Staff's proposed energy charges were close to the estimated average five-year marginal cost of energy. Staff proposed to lower all demand charges to meet its proposed revenue requirement for these classes.

The staff's rate design was revised to meet the established revenue requirement. The Commission finds staff's revised rate design, adjusted to the current revenue requirement, to be reasonable and just. The authorized customer class rates and revenues are shown in Appendix B.

Interruptible Credit

WPS proposed to use a "bottom-up" methodology to price interruptible capacity. WPS proposed to lower the fixed interruptible credit from \$5.50 to \$5.40 per kW and maintain the variable interruptible credit at \$4.40 per kW. WIEG supports WPS's bottom-up approach and recommends leaving the interruptible credits unchanged. Staff used WPS's avoided cost calculations using a peaker unit and reviewed the cost of peak capacity purchases in establishing the interruptible credits. Staff proposed lowering the interruptible credits by \$1.00. This reduction would establish the fixed interruptible credit at \$4.50 per kW and the variable interruptible credit at \$3.40 per kW. The Commission finds staff's method appropriate in setting the interruptible credits and finds the \$1.00 reduction in interruptible credits to be reasonable and just.

Interruptible Credit - Optional Load Factor Rate

The interruptible load factor optional rate was approved in docket 6690-UR-107. This program determined the monthly demand credit based on the on-peak interruptible load factor. The higher the load factor, the higher the credit. The program has been optional in the past, but is to

Docket 6690-UR-110

become mandatory in 1998.

WPS proposed to eliminate this option effective January 1, 1998. WPS proposed to keep the program for 1997 because some customers have already chosen the option for 1997 and nominated accordingly. Staff supported WPS's request to eliminate the interruptible load factor option, but further recommended that the program be eliminated for 1997. WPS supported eliminating the program in 1997 if it is allowed to adjust the projected revenues in the final rate design to accommodate the customers' revised interruptible nominations. The Commission finds staff's proposal to eliminate the interruptible load factor option in 1997, one year earlier than WPS's proposal, to be just and reasonable. The Commission further finds that projecting revenues in the final rate design to accommodate the customers' revised interruptible nominations to be just and reasonable.

Interruptible Default Nomination Process

WPS proposed to implement a default nomination process for interruptible loads. WPS currently has two deadlines for revising nominations; May 15 for the next calendar year nominations, and October 31 for years 2-5. WPS proposed that, should customers fail to submit a revised nomination for the next calendar year by May 15, it would use the nomination in place for the next calendar year. This nomination would have been last revised by October 31 of the previous year. WPS further proposed that should customers fail to submit revised nominations for years 2-4 and a new nomination for year five by October 31, it would use the previous year 2-4 nominations and use year four nominations for year five as well. Staff did not oppose applicant's proposal, but proposed the establishment of a customer notification policy to be included in the new process. The Commission finds WPS's interruptible default nomination process, with the inclusion of a customer notification policy, to be reasonable and just. The Commission finds that WPS should submit the customer notification

policy to the staff for review before implementing the new nomination process.

Minimum Demand Level for CP-I2

WPS proposed to lower the minimum demand required to qualify for the large commercial and industrial interruptible CP-I2 rider from the current minimum demand of 500 kW, to 200 kW.

Lowering the limit to 200 kW will allow more customers the opportunity to take service under this rider and provide WPS with additional interruptible load. The Commission finds a minimum demand of 200 kW to qualify for the CP-I2 rider to be reasonable and just.

Economic Buyout

WPS proposed to revise the dollar amount at which it is allowed to declare an economic buyout during times of interruption. The current level is \$80/MWh. WPS proposed to decrease this level to \$60/MWh to better reflect market conditions, including gas prices. WPS proposed that the revision would apply to all tariff riders with the current \$80/MWh limit. The Commission finds the revised \$60/MWh level for economic buyout to be reasonable and just.

Real Time Pricing

WPS proposed to offer customers served on the Cp-1 and Cp-2 rate schedules the option of purchasing energy from the Company at the marginal energy prices as determined on a day-ahead basis.

Staff determined that the WPS proposal did not contain enough information to adequately address the issue. Staff proposed that the Commission direct WPS to work with staff on this optional rate outside the context of a rate case. WPS agreed with staff's recommendation. WIEG proposed that it be a part of the development of any Real Time Pricing tariff. The Commission finds staff's proposal to work with WPS on the development of a Real Time Pricing optional tariff to be reasonable and just. The

Docket 6690-UR-110

Commission further finds that the Real Time Pricing tariff shall be submitted to WIEG for comment before being filed with the Commission.

Standard Buyback Rates

WPS presented an exhibit which showed that the current standard buyback rates should be decreased, and proposed decreasing the on-peak and off-peak energy payments by approximately 31 percent. WPS proposed to decrease the fixed charges for the buyback rate from \$9.00 to \$8.00 per month.

Tomahawk Power & Pulp Company (TPP) proposed that a PG-5 buyback rate be established which recognizes the superior value of power from renewable resources such as hydropower projects like TPP. TPP recommended that the Commission might want to consider including projects such as the TPP dam in a "green power" offering to those customers who appreciate the benefits of non-polluting power. While either the PG-5 rate or the green power proposals are being developed, TPP proposed to have the current on-peak and off-peak buyback rates held constant.

Renewable Energy in Wisconsin, Inc. (RENEW) proposed that the Commission should defer a decision on the new buyback rate. RENEW proposed that a collaborative with representation from RENEW, the hydro generators in WPS's territory, Commission staff, WPS, and customer participants be established. The collaborative would develop a customer-supported renewable energy acquisition program that would mix the planned expansions of hydro capacity with new investments in wind and biomass energy.

Staff agreed with WPS's proposal to decrease the fixed charge to \$8.00. Staff proposed buyback rates with approximately five percent lower on-peak and off-peak energy payments to mitigate the impact of the decreased rates to generators. The Commission finds that the staff's proposal is

Docket 6690-UR-110

reasonable and authorizes the buyback rates as shown in Appendix B.

The Commission did not authorize a PG-5 buyback rate and did not order WPS to establish a green power rate. Commissioner Eastman dissents on these two decisions.

Area Lighting

Staff addressed whether the Commission should consider area lighting a non-monopoly service. Staff presented options of discontinuing service for new or all area lighting customers, defining area lighting for future use, continuing service because ratepayers are not harmed, addressing the issue in restructuring docket 05-BU-101, and opening a generic docket. The Commission finds that rate payers are not harmed by the area lighting tariffed rates and that the utility may continue this service. The Commission further finds that area lighting should be addressed in the restructuring docket 05-BU-101.

Natural Gas Cost of Service Studies

Staff submitted two fully embedded cost-of-service studies. A cost-of-service study is a means of approximating the occurrence of actual costs that are experienced by the utility. An embedded cost study reviews the historical or projected future costs of providing utility service which are trended over time. In this proceeding, the costs are those anticipated for the 1997 test year. Staff's cost-of-service methodology A is a demand-customer oriented study under which the major plant accounts and expense accounts are allocated between demand and customer components on the basis of studies which have been done for various utilities to determine what portion of these accounts varies with the number of customers, regardless of how much gas is distributed, and what portion varies with a customer's demand for gas. Staff's B study uses the same logic while allocating more costs based on

Docket 6690-UR-110

commodity, or throughput.

Applicant submitted one fully embedded cost-of-service study using seven primary cost allocators. Applicant opposed staff's cost-of-service methodologies arguing that consideration of the studies results in unreasonably broad ranges of suggested cost recovery levels leading to a disconnect between rates and true cost-of-service.

The Commission found it reasonable to utilize staff's cost-of-service studies as a guide in setting rates in this proceeding.

Natural Gas Rate Design

Staff's rate design proposal included sweeping changes to Applicant's current rate structure. Staff argued that Applicant's current rate design contains some inherent flaws which can be addressed by implementing a rate design which utilizes annual throughput levels rather than the Applicant's current customer meter size concept. Applicant acknowledged certain weakness in its current rate design but argued these weaknesses are correctable without abandoning the current rate structure. Applicant submitted two rate design proposals. Applicant's preferred rate design proposal utilizes the Company's traditional meter class concept while adjusting class distribution margins consistent with its cost-of-service findings. Applicant also submitted an alternative rate design proposal which takes into consideration the same annual throughput requirements as used by staff.

Residential Rates

Staff's proposed rate design increases the residential monthly charge from \$4.00 to \$4.75 and increases the residential volumetric rate from \$0.1599 to \$0.1682. Applicant proposed to increase the residential customer charge from \$4.00 to \$4.95 and increase the volumetric rate from \$0.1599 to

\$0.1623.

Firm Commercial and Industrial Rates

Staff's rate design proposal takes into consideration annual throughput levels as compared to the Company's current connected load or meter size concept. Staff's rate design distinguishes between three different levels of annual throughput and identifies customer groupings as small, medium, and large. Staff's proposal identifies Applicant's former firm commercial and industrial meter classes 1-2 as small with annual usage less than 20,000 therms, the former meter classes 3-4 have been identified as medium with annual throughput levels of 20,000-200,000 therms, and finally, the former meter classes 5-6 fall into the large customer category with annual throughput greater than 200,000 therms.

Interruptible Commercial and Industrial Rates

Staff's annual throughput rate design concept carries into the interruptible customer classes. The primary difference is that there is no small interruptible class since the small volumes of gas do not warrant interruptible service. Staff's proposal includes a medium interruptible class with annual usage between 20,000-200,000 therms. A large interruptible class with annual throughput greater than 200,000 therms. And finally, a Super Large customer class with annual throughput exceeding 200,000 therms per month or 2,400,000 therms annually.

Transportation Classes

Staff's proposal for transportation service reflects the same annual throughput requirements. Staff also proposed to decrease the monthly transportation administrative charge from \$140.00 to \$100.00 while Applicant proposed to increase the charge from \$140.00 to \$150.00.

The Commission finds that staff's rate design, including the monthly transportation charge of \$100, is reasonable for the purpose of achieving the final revenue requirement in this proceeding. In addition, the Commission finds that Applicant's request to allow for a 10 percent tolerance above and below the class annual thresholds to account for aberrant weather variances is reasonable. The Commission denies Applicant's request to allow for a six month transition period for the implementation of rates, and instead, orders Applicant to implement the new rate design immediately upon issuance of this order. The Commission directs Applicant to treat the former meter class 1-2 customers as small, 3-4 customers as medium, and 5-6 as large. Customers falling outside of their initially assigned class should be moved to the appropriate class in a timely fashion.

Authorized rates and rules, shown in Appendix C, will provide an increase in annual Wisconsin retail natural gas revenues of \$5,687,000.

The Commission directed the Company to keep its customers informed of the new rate structure with added efforts directed towards customers who will realize an increase in their rates.

Reallocation of Natural Gas Capacity Costs

Applicant proposed to allocate a portion of its D1 costs to the D2 rate component to better ensure that interruptible customers pay for its share of the system's capacity costs. Staff supported Applicant's proposal. The Commission finds that Applicant's proposal to shift more capacity costs to system interruptible customers is reasonable.

Exit of Customers From a Marketer's Pool

Staff proposed language requiring a marketer to provide three business days written notice to the Company prior to discharging a customer from their pool. Applicant agreed with staff for the most

Docket 6690-UR-110

part, adding that the Company should reserve the right to deny firm service until adequate firm capacity and supplies can be lined up on the interstate pipelines.

The Commission finds that three business days is a reasonable time period for Applicant to review the situation involving a discharged pool customer. This decision strikes a balance between the interests of the marketer, who does not want to serve a defaulting customer and that of Applicant, who needs a reasonable amount of time to determine whether it has sufficient supplies and capacity to serve the customer, and whether a deposit should be required. The Commission acknowledges that the unregulated marketer is placed in the unenviable position of having to continue to flow gas to a customer who may not pay. However, the Commission will not insulate marketers from ordinary business risk by requiring a local distribution company (LDC) to pick up a marketer's delinquent customers without allowing the LDC adequate time to take appropriate action. This decision is consistent with the Commission's decisions in docket 6650-GR-114 and docket 6630-UR-109.

Gas Supply Acquisition Charge (Gas Margin)

A major step in moving toward the new functional categories approved in Docket 05-GI-108, Phase I, is to remove any gas supply related costs from the distribution margin rate. The distribution margin rate is intended to reflect the cost of distributing natural gas to customers once it arrives at the city gate. It should not include any costs associated with procuring natural gas, unless such gas is necessary to keep the distribution system operating efficiently. Under current rate design practices, some gas supply related costs are included in the distribution margin charge. Because this charge is paid by both sales customers and transportation customers, transportation customers are made to pay for some of the gas supply acquisition costs associated with serving sales customers. The intent of the gas supply acquisition charge is to create a separate rate that is charged only to system sales customers. In

Docket 6690-UR-110

this docket, the gas supply acquisition charge consists of the carrying cost of gas in storage which is approximately \$1,821,000 plus an additional \$1,200,000 which is an estimate of other gas supply related costs unaccounted for in this proceeding such as payroll related to O&M, taxes, and plant items.

The Commission finds that staff's creation of a separate gas acquisition rate is reasonable and should be assessed against all system customers. This decision is consistent with the decision rendered in docket 6630-UR-109.

Itemization of Natural Gas Rate Components of Customer Bills

In addition to the new gas acquisition rate discussed above, staff proposed to include more specific billing information on a customer's bill including: # (1) monthly fixed or facilities charge; # (2) basic distribution charge; # (3) purchased gas adjustment charge and; # (4) gas base rate. While Applicant did not oppose staff's proposal it conditioned its support on a sample bill being offered as part of this order.

The Commission finds that the customers' bills should be itemized into the following categories:

Utility Service:

Monthly Customer or Facilities Charge
Distribution Service Rate

Gas Supply Service:

Gas Supply Acquisition Rate
Gas Base Rate
Gas Adjustment Rate

The Commission feels that the separation of the natural monopoly distribution service from the competitive gas supply service will help to educate customers as to the aspects of the business where

Docket 6690-UR-110

they will potentially have choices, and those that will remain regulated. For the purposes of this rate proceeding, these rate components need only be illustrated where customers have the option of taking transportation service. As the transportation market evolves, the Commission anticipates that all customer bills will reflect these components. These changes to the billing format may take a considerable amount of time to implement. Recognizing the need for lead time in this regard, the Commission finds that it is reasonable that the Company have until January 1, 1998, for implementation of these changes.

Capacity Costs Resulting from Customers Moving to Natural Gas Transportation Sales

Staff testified Applicant's waiver of its tariffed 12-month notification period for customers moving from system sales to transportation in order to obtain additional capacity was both inappropriate and unauthorized. Staff recommended that if the capacity in question is later found to be excessive or unnecessary, the Commission should disallow its recovery. At the time of the hearings, a dollar amount had not yet been determined.

Applicant acknowledged that, while the process used to obtain the needed capacity may not have been proper, the added capacity should not be considered excessive or unwarranted. Applicant argued that there was an error in its natural gas supply plan from the previous year leading to an overstated peak day requirement for the 1996-97 heating season.

The Commission determines that the cost of any excess capacity related to customers moving from system sales to transportation without the required 12-month notification period should not be borne by the core ratepayers. The issue of capacity cost is appropriately addressed in the purchased gas adjustment (PGA) review process.

True Pooling

Under current transportation pooling practices, charges for some aspects of the pool are billed on an account-by-account basis. This reduces some of the benefits of pooling. Staff proposed that the Commission require Applicant to adopt what is known as "true pooling." Under true pooling, more accounting for gas supply related costs is done at the pool level. Thus, more of the benefits of the diversity of pooling can go to the ratepayer and Applicant's administrative costs are reduced. It should be noted that the decision on true pooling affects the monthly cash out procedure. For example, under true pooling, a marketer could allocate across customer classes taking advantage of the new gas acquisition charge resulting in Applicant under-recovering its costs. Consequently, the Commission finds it appropriate to restrict marketer reallocations of volumes or nominations across customer classes during the end-of-month cash out procedure. Therefore, the Commission finds that true pooling is reasonable, but shall be restricted to reallocations within customer classes for purposes of end-of-month cash out.

Standardized Natural Gas Tariff Language for Unauthorized Use Penalties

In the winter of 1995-96, most if not all of the state's natural gas utilities experienced difficulties with customers taking unauthorized natural gas. In some cases, while the tariffs clearly indicate that severe penalties could be incurred by customers taking unauthorized natural gas, some customers chose to ignore the requests of the utilities to interrupt or limit their use of natural gas. As a result, significant penalties were incurred by some noncomplying customers who expressed concerns with the level of the penalties imposed by the LDCs and the apparent inconsistency among various LDCs concerning the circumstances under which the higher penalties had to be assessed.

In order to ensure that utility unauthorized usage penalty tariffs were clear and consistent, staff

Docket 6690-UR-110

proposed standardized unauthorized usage penalty language for all LDCs and circulated its proposal for comments. Both staff's letter and Applicant's response letter were entered in the record in this case. Applicant generally supported staff's proposal on a prospective basis. Staff's proposal requires that, when WPS declares a high flow constraint day, all transportation customers are limited to their confirmed nominations. Usage greater than confirmed nominations is unauthorized usage of natural gas and is subject to a penalty rate of \$2.00 per therm. If ANR pipeline, which provides the transportation to Applicant's city gates, declares a critical alert day, such as the declaration of a cease and desist situation, then the unauthorized use penalty rate for Applicant's transportation customers becomes \$10.00 per therm plus any additional expenses incurred by WPS as a result of the customer's actions.

Under staff's proposed penalty provisions, interruptible customers that take unauthorized gas will be subject to the same \$2.00 per therm penalty rate as transportation customers. As is the case with transportation customers, the unauthorized use penalty rate increases to \$10.00 per therm if the pipeline declares a critical alert situation. All noncomplying customers, whether transportation customers or system interruptible customers, must be assessed these penalties regardless of the incurrence of pipeline penalties by Applicant. This is necessary to protect the integrity of the natural gas system.

The Commission finds staff's unauthorized usage penalty provisions, as stated above, are reasonable and will order WPS to amend its tariff language accordingly. Applicant is directed to work with staff to ensure that its penalty language is, where appropriate, consistent with the unauthorized use language recently approved in other cases before the Commission. In addition, Applicant should ensure that all of its customers are aware of the unauthorized usage penalty tariff provisions.

Compliance With Current Unauthorized Natural Gas Use Penalty Language

Staff testified that WPS did not follow its tariffs in the issuance of unauthorized use penalties during the extreme weather conditions in late January and early February of 1996. Staff testified that Applicant should have issued penalties at the pipeline cease and desist level rather than the much lower \$2.00 level. Staff supported its position by citing relevant order points and findings in the Phase II Order of Generic Docket 05-GI-103. Applicant argued its unauthorized use penalty provision only allows the issuance of the higher pipeline cease and desist penalties when those penalties are imposed by the pipeline. Applicant further testified that its customers were informed that the penalty for unauthorized use would only exceed \$2.00 per therm when a higher pipeline penalty was actually incurred by the Company.

The Commission finds that its Phase II Order in docket 05-GI-103 clearly requires LDCs to impose the higher pipeline penalty rates on noncomplying customers for unauthorized use of natural gas, whether or not the LDC actually incurs a pipeline penalty on that day. The reason for this policy is clear: in order for the unauthorized use penalty to act as a deterrent, the effective pipeline penalty must be assessed regardless of whether the LDC actually receives one. Otherwise, customers who had no entitlement to use the LDC's natural gas on a pipeline constraint day could nevertheless take gas, in effect betting that the LDC would not actually receive a pipeline penalty on that constraint day. If a significant amount of natural gas were used by such customers, the LDC might have to curtail firm customers who were entitled to such gas.

The Commission also finds that WPS's penalty provision for unauthorized use of natural gas which was filed in compliance with 05-GI-103, does not limit the imposition of the higher pipeline penalty rate only to situations in which the utility actually receives a pipeline penalty. The language in question provides as follows:

SURCHARGE FOR UNAUTHORIZED USE OF GAS. The customer shall be

Docket 6690-UR-110

required to pay a surcharge of \$2.00 per therm or pipeline penalty rate per therm, whichever is greater, for all unauthorized use of gas during a period of curtailment or suspension of gas service ordered by the company in addition to any other charges payable under this schedule.

This language is clear that the rate for unauthorized usage of gas is the higher of \$2.00 per therm or the pipeline penalty rate per therm and the tariff is consistent with the Phase II Order in docket 05-GI-103.

Consequently, the Commission finds that Applicant must back bill customers for unauthorized usage of gas at the higher pipeline penalty rate during the cease and desist declaration period in January and February of 1996. Based on the record in this proceeding, ANR's cease and desist penalty rate approached \$10.00 per therm.

Natural Gas Curtailment Plan Revisions

Applicant submitted a revised curtailment plan in response to a letter from the Commission dated June 11, 1996, requesting a plan or priority of interruptions. Staff supported Applicant's revised curtailment plan but conditioned its support based on the Commission's determination of a rate design in this proceeding. The Commission finds that Applicant's revised curtailment plan is reasonable once adjusted for the new customer classes discussed in the rate design section above.

Effective Date of Order

The test year in this case commences January 1, 1997. Pursuant to s. 196.40, Stats., an order or determination of the Commission shall take effect 20 days after the order or determination has been filed and served on the parties to the proceeding unless the Commission specifies a different effective date in the order or determination.

The Commission finds, because the test year has already commenced, it is reasonable that this

Docket 6690-UR-110

order be effective one day after the date of issuance, at which time the utility shall immediately inform the Commission in writing of the date the newly authorized rates and rules have taken effect. The authorized electric and natural gas rates and rules shall be filed with the Commission and placed in all offices and pay stations of the utility by that date in accordance with ss. 196.21 and 196.40, Stats.

Environmental Review

This is a Type III action under s. PSC 4.10(3), Wis. Adm. Code. Furthermore, since no unusual circumstances have come to the attention of the Commission which indicate that significant environmental consequence are likely, neither an environmental impact statement under s. 1.11, Stats., nor an environmental assessment is required.

ULTIMATE FINDINGS OF FACT

THE COMMISSION FINDS:

1. Presently authorized rates for WPS's electric and natural gas utility service will produce Wisconsin retail electric operating revenues of \$455,156,000 for the test year ending December 31, 1997, which exceed the electric revenue requirement by \$35,514,000. Presently authorized rates for WPS's natural gas utility service will produce Wisconsin retail natural gas operating revenues of \$212,335,000 for the test year ending December 31, 1997, which falls short of the natural gas revenue requirement by \$5,687,000. Presently authorized rates would also produce estimated Wisconsin retail electric net operating income of \$81,264,000 and estimated Wisconsin natural gas net operating income of \$10,784,000. Presently authorized rates for electric service are unreasonable and unjust because they produce excessive electric revenues. Presently authorized rates for natural gas utility service are unreasonable and unjust because they produce inadequate natural gas revenues.

2. For the electric utility, the estimated rate of return on average net investment rate base at current rates subject to the Commission's jurisdiction for the test year is 14.52 percent, which is excessive.

3. For the gas utility, the estimated rate of return of average net investment rate base at current rates subject to the Commission's jurisdiction for the test year is 8.24 percent, which is inadequate.

4. A reasonable and just decrease in operating revenue requirement for the test year to produce an 10.72 percent return on WPS's average net investment rate base for Wisconsin retail electric operations, is \$35,514,000.

5. A reasonable and just increase in operating revenue requirement for the test year to produce an 10.84 percent return on WPS's average net investment rate base for Wisconsin natural gas operations is \$5,687,000.

6. It is reasonable to determine revenue requirement for the biennial period by using 1997 financial projections adjusted for "known and significant" items forecasted to occur in 1998.

7. It is not reasonable to order WPS to file annual rate cases.

8. It is reasonable for rates in this proceeding to be effective for 1997 and 1998.

9. It is not reasonable to include WPS's sales forecast for Large Commercial and Industrial customers that was provided to Commission staff after the audit was completed.

10. It is reasonable to fully allocate the costs associated with the original contract with Oconto REC to the wholesale jurisdiction.

11. It is reasonable to treat the loss in 1998 of WPPI as a firm, wholesale customer as a "known and significant" item and normalize its impact over both years of the biennial period.

12. It is reasonable to provide rate recovery for the normalized levels of fuel and non-fuel

Docket 6690-UR-110

O&M costs associated with both the 1997 mid-cycle shutdown of Kewaunee and the 1998 refueling outage. It is reasonable that these amounts be made subject to refund in the event that one or both of these outages does not occur, as described in the Findings of Fact.

13. It is reasonable to include the annuity amounts for Kewaunee decommissioning and the depreciation rates for Kewaunee authorized by the Commission in docket 05-DE-100 in electric revenue requirement. It is also reasonable for WPS to begin recording the new depreciation and decommissioning amounts at the same time as the effective date of the order in this proceeding.

14. Due to the uncertainties associated with the repair of the KNPP steam generators, it is reasonable to consider that the KNPP is out of service indefinitely. It is also reasonable that \$67,000 per day should be used as an estimate of the incremental fuel costs to be incurred by WPS to replace its share of the output from the KNPP.

15. It is reasonable to increase the existing rates to recover the incremental fuel costs associated with replacing KNPP during the test year by giving a temporary \$0.00228 per kWh surcharge for all applicable rate schedules in Appendix D.

16. It is also reasonable that the temporary surcharge in Ultimate Finding Number 15 be applied for service rendered on and after the effective date of this order until such time that the KNPP is put back into service from the current extended 1996 refueling outage. It is reasonable that WPS shall designate the surcharge as a separate item on customer bills for consumer information.

17. It is reasonable to include pre-engineering costs associated with the steam generator replacement project for KNPP in CWIP for the electric utility.

18. It is reasonable to exclude amounts projected by WPS for a waterwall replacement project and a turbine overhaul at its Pulliam 3 generating unit.

19. It is not reasonable to include the new budget estimates for WPS's share of O&M costs

for Columbia and Edgewater that were provided to Commission staff after the audit was completed.

20. It is reasonable to exclude costs associated with activities not directly related to the provision of gas and electricity, or that could be performed by nonutility businesses in a competitive environment, as identified by Commission staff.

21. It is reasonable to exclude costs associated with WPS's plans to physically relocate its transmission staff to an off-site office.

22. Services provided to UPPCO are considered to be a utility function in the wholesale jurisdiction. It is reasonable to assign the revenues and fully-allocated costs associated with these services to the wholesale jurisdiction.

23. It is reasonable that Applicant's gas servicing activities, as described in the Findings of Fact, be accounted for as a nonutility activity on a fully-allocated basis, including all direct and indirect costs.

24. WPS's conservation, safety, informational, and instructional advertising programs included in rates provide direct and substantial benefits to its ratepayers.

25. A demand-side management budget of \$9,547,000 is reasonable for financial planning and in determining the test year revenue requirement. It is also reasonable that all of these expenditures be escrowed.

26. It is reasonable for WPS to discontinue the practice of deferring certain demand-side investments, described in the Findings of Fact, beginning in 1997.

27. It is reasonable for WPS to amortize the remaining deferred conservation expenditures over a five-year period. It is reasonable that the amortization amount for the test year should be \$5,500,000 for electric operations and \$2,000,000 for gas operations to provide for revenue levelization.

28. It is reasonable for WPS to earn a current return on the remaining unamortized balance of deferred conservation expenditures.

29. It is reasonable for WPS to amortize the estimated underspent escrow balances at the end of 1996 over the biennial period at a rate of \$2 million per year for electric operations and \$1.5 million per year for natural gas operations.

30. It is reasonable to include WPS's estimate of post-retirement medical expense in revenue requirement for electric and natural gas operations.

31. The Commission staff rate treatment that begins the initial amortization of MGP clean-up costs that had been previously deferred is reasonable. Because sharing of the MGP clean-up costs between ratepayers and shareholders should be achieved, the Commission also finds it reasonable that the unamortized balance of the deferral account should not be included in working capital.

32. It is reasonable to include the investment in diesel generators located on property owned by the Oneida Nation in net investment rate base as utility property.

33. It is reasonable to reflect AEP surcharges, both past and future, as reductions to the cost of construction. It is also reasonable to conclude that Commission staff's correcting entries do not result in retroactive ratemaking.

34. Rate recovery of WPS's payments to the Department of Energy for the Decontamination and Decommissioning special assessment is not reasonable. This finding assumes an aggressive tax position that relies on the Yankee Atomic decision described in the Findings of Fact.

35. The collection of customer billing information for the purpose of reimbursing its ratepayers in the event WPS receives a refund or some form of credit from the DOE for the D&D assessments is reasonable.

36. A reasonable estimated fuel cost for the test year, reflecting cost of generation,

Docket 6690-UR-110

purchased energy, wheeling, and capacity less the revenue from opportunity sales of energy and capacity, is \$131,424,000 for 11,381,855 MWh, or \$0.01155 per kWh.

37. The following variance ranges are reasonable for monitoring Applicant's fuel costs pursuant to Ch. PSC 116, Wis. Adm. Code: 1) for the annual range, plus or minus 2 percent; 2) for the monthly range, plus or minus 8 percent; and 3) for the cumulative range, plus or minus 8 percent for the first month of the test year, plus or minus 5 percent for the second month of the test year and plus or minus 2 percent for the remaining months of the test year and until the next rate order.

38. A reasonable estimate of fuel costs for each month of the biennial period is attached as Appendix D which will be used for required monthly monitoring of the fuel cost pursuant to Ch. PSC 116, Wis. Adm. Code. The monthly fuel cost estimates in Appendix D underlie rates excluding the interim surcharge for the KNPP replacement fuel costs. For those days that the surcharge is in effect, the estimated fuel costs monitored should include an additional \$67,000 per day.

39. The reasonable utility ratemaking capital structure consists of 54.80 percent common stock equity, 6.45 percent preferred stock, 36.72 percent long-term debt, and 2.03 percent short-term debt.

40. The reasonable utility financial capital structure, which includes effects of the leveraged ESOP, consists of 53.70 percent common stock equity, 6.32 percent preferred stock, 37.99 percent long-term debt and debt equivalents, and 1.99 percent short-term debt.

41. A reasonable utility financial capital structure, which includes effects of the leveraged ESOP, consists of 47 to 54 percent common stock equity. The 54 percent threshold represents an increase over the Commission's prior 52 percent common equity guideline. The test year's 53.70 percent common stock equity is within the new Commission guideline. The utility capital structure will continue to be reviewed periodically.

42. A return on utility common stock equity of 11.80 percent is reasonable for WPS in this proceeding.

43. A short-term debt rate of 5.40 percent is reasonable for WPS in this proceeding.

44. A weighted average composite cost of capital of 9.71 percent is reasonable for WPS in this case.

45. For the test year, 50 percent of average CWIP should earn a current return and the remaining CWIP should earn an AFUDC return of 10.37 percent.

46. All prior dividend restrictions remain in force.

47. It is reasonable for WPS to submit a ten-year financial forecast in all future rate cases before this Commission as discussed in the Findings of Fact.

48. The appropriate test year rates of return on net investment rate base, including a current return on 50 percent of average CWIP and on all of the average capitalized conservation investments, is 10.72 percent and 10.84 percent for electric and gas operations, respectively.

49. In order to provide operating revenues to cover the total cost of service for the biennial period ending December 31, 1998, a decrease in rates applicable to Wisconsin retail electric service in the amount of \$35,514,000 annually is required. This decrease in rates and revenues is reasonable.

50. In order to provide operating revenues to cover the total cost of service for the biennial period ending December 31, 1998, an increase in rates applicable to Wisconsin retail natural gas service in the amount of \$5,687,000 annually is required. This increase in rates and revenues is reasonable.

51. A gas sales promotion budget of zero dollars for the 1997 test year is reasonable.

52. Any future gas sales promotion budget must be justified as required by dockets 05-GI-101 and 05-UI-103 and as described in the Findings of Fact.

53. Including the cost of any gas sales promotion in the AEP surcharge must be justified as described in the Findings of Fact.

54. Total Company electric demand-side management (DSM) goals of 94.6 GWh, with a low-income goal of 1.55 GWh, for 1997 and 1998, are reasonable and appropriate.

55. It is reasonable and appropriate to establish total Company natural gas DSM goals, for each of 1997 and 1998, of 4.483 million therms -- with sector therm targets for Residential of 1,294,250 therms; Commercial of 1,085,000 therms; Industrial of 472,000 therms; Rental of 450,750 therms; and Transportation of 700,000 therms. A Low-income goal of 481,000 therms for 1997 and 1998 is reasonable and appropriate.

56. It is reasonable and appropriate to re-establish a residential electric DSM goal of 24.1 GWh for WPS for each of 1997 and 1998.

57. It is reasonable and appropriate to direct WPS to develop a plan, as described in the Findings of Fact, within 120 days of the date of this order, for the transition to complete competitive acquisition of ratepayer-funded DSM services by the end of 1998. Prior to drafting the plan, WPS should work with Commission DSM staff to develop a framework for the plan, as described in the Findings of Fact.

58. The expenditures requested in this proceeding for technology assessment of electric vehicles, photovoltaics, and fuel cells are not conservation and not appropriate for conservation escrow coverage. These research and development expenditures, however, are reasonable and appropriate to include in the revenue requirement.

59. It is reasonable and just to maintain the current rate territories for all electric rate classes except the small commercial and industrial (TOD) classes. It is reasonable to combine the small commercial and industrial (TOD) Cg-1 and Cg-2 classes into one class called small commercial and

Docket 6690-UR-110

industrial (TOD), Cg-1.

60. It is reasonable and just to lower the monthly credit for shedding electric water heaters under the Rg-DC and Cg-DC riders to \$2.00.

61. It is reasonable and just to lower the electric interruptible credits by \$1.00, as shown in Appendix B.

62. It is reasonable and just to eliminate the electric interruptible load factor option in 1997 and reflect customers' revised interruptible nominations in the rate design authorized in this order.

63. It is reasonable and just to revise the interruptible default nomination process so that customers that fail to submit a revised nomination for the next calendar year by May 15, would use the nomination in place for the next calendar year. Customers that fail to submit revised nominations for years 2-4 and a new nomination for year five by October 31, would use the previous year 2-4 nominations and use year four nominations for year five as well. It is reasonable and just for WPS to submit a customer notification policy for this revised process to the Commission staff for review before implementing the new nomination process.

64. It is reasonable and just to require a minimum demand of 200 kW to qualify for the industrial interruptible CP-I2 rider.

65. It is reasonable and just to revise the dollar amount at which it is allowed to declare an economic buyout to \$60/MWh.

66. It is reasonable and just for WPS and staff to develop a Real Time Pricing optional tariff and submit it to WIEG for comment before being filed with the Commission.

67. It is reasonable and just to lower WPS's buyback rates as shown in Appendix B.

68. It is reasonable and just to address issues relating to the non-monopoly aspect of area lighting in docket 05-BU-101 and that area lighting tariffs remain unchanged until the decision is made in

that docket.

69. The rate and rules changes set forth in Appendices B and C for retail electric and natural gas utility service will permit Applicant to earn the necessary operating revenue requirement, are consistent with the previous Findings of Fact relating to electric and gas revenue allocation, rate design, and cost of service information, and are reasonable and just.

70. Staff's natural gas cost-of-service studies form a reasonable basis for establishing just and reasonable rates in this proceeding.

71. Staff's rate design proposal which abolishes Applicant's current connected load or meter class concept in favor of an annual throughput concept is reasonable. The annual throughput concept will be applicable to all Commercial and Industrial customers for both system and transportation service.

72. Applicant's proposal to reallocate a portion of their peak demand charges (D1) to the annual demand (D2) rate component is reasonable and will help to ensure that interruptible customers pay for their share of system capacity costs.

73. It is reasonable for Applicant to require a marketer to provide at least three business days to the Company before abandoning service to a customer.

74. The creation of a separate gas acquisition charge to be assessed against system customers only is reasonable.

75. Applicant's natural gas customers' bills should be itemized, consistent with the Findings of Fact, into the following categories: Utility Services; Customer/Facilities Charge and Distribution Service Rate; Gas Supply Service; Gas Supply Acquisition Charge, Gas Base Rate and Gas Adjustment Rate. The Commission finds that it is reasonable that the Company have until January 1, 1998, to implement these billing format changes.

76. Applicant's waiver of the 12 month notification period for customers moving from

system sales to off-system sales was inappropriate and unauthorized. The Commission finds that any costs related to the added capacity, if determined to be excessive, will not be recoverable through the purchased gas adjustment mechanism.

77. The use of true pooling for transportation pools, as described in the Findings of Fact, is just and reasonable. In implementing true pooling, Applicant should prohibit reallocations of volumes or nominations across customer classes for the monthly cash out procedure.

78. The stated rate for unauthorized use of \$10.00 per therm is a reasonable penalty for unauthorized consumption of natural gas on critical days when the pipeline has a declaration of cease and desist, or its equivalent, in place. A lower penalty of \$2.00 per therm is reasonable for unauthorized use on days other than the critical days described above. In addition to these per therm penalties, it is reasonable to include in the penalty any additional costs incurred by WPS as a result of the customer's actions. These penalties shall be assessed against a non-complying customer whether or not a pipeline has assessed a penalty to the Company.

79. It is reasonable for Applicant to back bill customers for unauthorized usage which took place during the late January and early February 1996 cold spell. Applicant shall back bill these customers at the ANR cease and desist penalty level for the duration of the pipelines cease and desist period. The level of penalty should approximate \$10.00 per therm.

80. Applicant's curtailment plan is reasonable once adjusted for the new customer classes discussed in the rate design section above.

81. It is reasonable that this order be effective one day after the date of issuance, on which day Applicant shall inform the Commission in writing that the newly authorized rates and rules have taken effect. The authorized electric and natural gas rates and rules shall be filed with the Commission and placed in all offices and pay stations of the utility by that date, in accordance with ss. 196.21 and

Docket 6690-UR-110

196.40, Stats.

82. This is a Type III action under s. PSC 4.10(3), Wis. Adm. Code. Furthermore, since no unusual circumstances have come to the attention of the Commission which indicate that significant environmental consequences are likely, neither an environmental impact statement under s. 1.11, Stats., nor an environmental assessment is required.

CONCLUSION OF LAW

THE COMMISSION CONCLUDES:

It has jurisdiction under ss. 1.11, 1.12, 196.02, 196.03, 196.19, 196.20, 196.21, 196.37, 196.395, and 196.40, Stats., and ch. PSC 116, Wis. Adm. Code, to enter an order authorizing Wisconsin Public Service Corporation to place in effect the rates and rules for electric and gas utility service set forth in Appendices B and C, and the fuel treatment set forth in Appendix D, subject to the conditions specified in this order.

ORDER

THE COMMISSION THEREFORE ORDERS:

1. WPS is authorized to substitute for its existing rates and rules for retail electric and natural gas service, the rate and rule changes contained in Appendices B and C attached and made a part of this order.
2. WPS is authorized to apply the rates in Appendices B and C, attached, to bills rendered for electric and natural gas service under the jurisdiction of the Commission.
3. This order shall be effective one day after the date of issuance. The utility shall inform the Commission in writing when the newly authorized rates and rules have taken effect.
4. WPS shall prepare bill inserts which properly identify the rates authorized in this order. Copies of such inserts shall be sent to the Commission. WPS shall distribute these inserts to customers with the first billing containing these rates.
5. WPS may apply a temporary surcharge of \$0.00228 per kWh to all applicable rate schedules as shown in Appendix D for service rendered on or after the effective date of this order. WPS shall discontinue the surcharge, effective the date that the KNPP is put back into service from the current extended 1996 refueling outage. WPS shall notify its customers with an explanation of this temporary surcharge and shall designate the surcharge as a separate item on customer bills.
6. The normalized level of fuel and non-fuel O&M costs associated with both the 1997 midcycle shut down of KNPP and the 1998 refueling outage of KNPP is subject to refund, as described in the Findings of Fact.
7. WPS shall maintain appropriate records to enable the Commission to determine the necessity of refunds associated with KNPP outages in 1997 and 1998 and to enable refunds to customers, if required and ordered by the Commission.

8. WPS shall account for gas servicing activities as a non-utility activity, as described in the Findings of Fact, on a fully-allocated basis, including all direct and indirect costs, as of the effective date of this order.

9. WPS shall use a demand-side budget of \$9,547,000 for financial planning and in determining test year revenue requirement and shall escrow all of these expenditures.

10. WPS shall discontinue the practice of deferring certain demand-side investments, described in the Findings of Fact, beginning in 1997.

11. WPS shall amortize the remaining deferred conservation expenditures over five years. The annual amortization amounts, for each year of the biennial period, shall be \$5,500,000 for electric operations and \$2,000,000 for natural gas operations.

12. WPS shall amortize the estimated underspent escrow balances as of December 31, 1996, over the biennial period at a rate of \$2 million per year for electric operations and \$1.5 million per year for natural gas operations.

13. WPS shall report monthly to the Commission its actual total system cost of generation, purchased energy, capacity, and wheeling costs less the revenues from opportunity sales of energy and capacity. WPS shall otherwise comply with the fuel cost determination and monitoring system as set forth in the Findings of Fact.

14. WPS shall start collecting customer billing information for the purpose of reimbursing its ratepayers for any refunds that are received from the Department of Energy for the Decontamination and Decommissioning special assessments.

15. WPS shall submit a ten-year financial forecast in all future rate cases before the Commission, as discussed in the Findings of Fact.

16. WPS shall abide by previously established dividend restrictions.

17. WPS shall properly reflect all AEP surcharges, beginning with the inception of the program, as reductions to the cost of construction.

18. WPS shall adopt the total Company electric DSM goals, electric low-income goals, and electric residential goals, as described in the Findings of Fact. WPS shall also adopt the total Company natural gas DSM goals, gas low-income goals, and gas sector minimum targets, as described in the Findings of Fact.

19. WPS shall develop a plan, as described in the Findings of Fact, within 120 days of the order, for the transition to complete competitive acquisition of ratepayer-funded DSM services by the end of 1998. WPS shall work with Commission DSM staff to develop a framework for the plan, prior to drafting the plan, as described in the Findings of Fact.

20. WPS shall maintain the current rate territories for all electric rate classes except the small commercial and industrial (TOD) classes. WPS shall combine the small commercial and industrial (TOD) Cg-1 and Cg-2 electric rate classes into one class called small commercial and industrial (TOD), Cg-1.

21. WPS shall lower the monthly credit for shedding water heaters under the Rg-DC and Cg-DC riders to \$2.00.

22. WPS shall decrease the interruptible credit by \$1.00 per kW for the credit levels as shown in Appendix B.

23. WPS shall eliminate the interruptible load factor option in 1997 and reflect customers' revised interruptible nominations in the rate design authorized in this order.

24. WPS shall revise the interruptible default nomination process so that customers that fail to submit a revised nomination for the next calendar year by May 15 will use the nomination in place for the next calendar year. Customers that fail to submit revised nominations for years 2-4 and a new

Docket 6690-UR-110

nomination for year five by October 31 will use the previous year's 2-4 nominations and use year four nominations for year five as well. WPS shall submit a customer notification policy for this revised process to the Commission staff for review before implementing the new nomination process.

25. WPS shall require a minimum demand of 200 kW to qualify for the electric industrial interruptible CP-I2 rider.

26. WPS shall revise the dollar amount at which it is allowed to declare an economic buyout to \$60/MWh.

27. WPS shall work with staff to develop a Real Time Pricing optional tariff outside this order and submit it to WIEG for comment before being filed with the Commission.

28. WPS shall lower its buyback rates as shown in Appendix B.

29. WPS may address issues relating to the non-monopoly aspect of area lighting in docket 05-BU-101, and shall leave area lighting tariffs unchanged until the decision is made in that docket.

30. WPS shall reallocate a portion of peak demand charges (D1) to the annual demand component to better reflect the cost responsibilities associated with interruptible service.

31. WPS shall draft tariff language which requires marketers to provide at least three business days notice to WPS before abandoning service to a customer.

32. WPS shall itemize the following rate components on customers' bills consistent with the Findings of Fact. For utility service; Distribution Service Rate and Customer/Facilities Charge. For gas supply service; Gas Supply Acquisition Rate, Gas Base Rate and a Purchased Gas Adjustment Rate.

33. WPS shall implement true pooling as discussed in the Findings of Fact and prohibit marketer reallocations of volumes or nominations across customer classes for the monthly cash out procedure.

Docket 6690-UR-110

34. WPS shall implement a stated penalty rate for unauthorized natural gas use at \$10.00 per therm for critical days and \$2.00 per therm for unauthorized use on other days; plus any additional costs incurred by WPS as a result of the customer's actions. The penalty rate will be assessed regardless as to whether the LDC receives any penalty from the pipeline.

35. WPS shall back bill customers for unauthorized usage of natural gas at the pipeline's cease and desist penalty rate for unauthorized usage during the late January and early February 1996 cold spell.

36. WPS shall file a curtailment plan which reflects the rate design attached as Appendix C.

37. Jurisdiction is retained.

Dated at Madison, Wisconsin, February 20, 1997

By the Commission.

/s/ Lynda L. Dorr
Lynda L. Dorr
Secretary to the Commission

LLD:CAS:mad:h:\6690UR.110\WPSUR110.ORD
See attached Notice of Appeal Rights

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in s. 227.53, Stats. The petition must be filed within 30 days after the date of mailing of this decision. That date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in s. 227.01(3), Stats., a person aggrieved by the order has the further right to file one petition for rehearing as provided in s. 227.49, Stats. The petition must be filed within 20 days of the date of mailing of this decision.

If this decision is an order after rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not an option.

This general notice is for the purpose of ensuring compliance with s. 227.48(2), Stats., and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

Revised 4/22/91